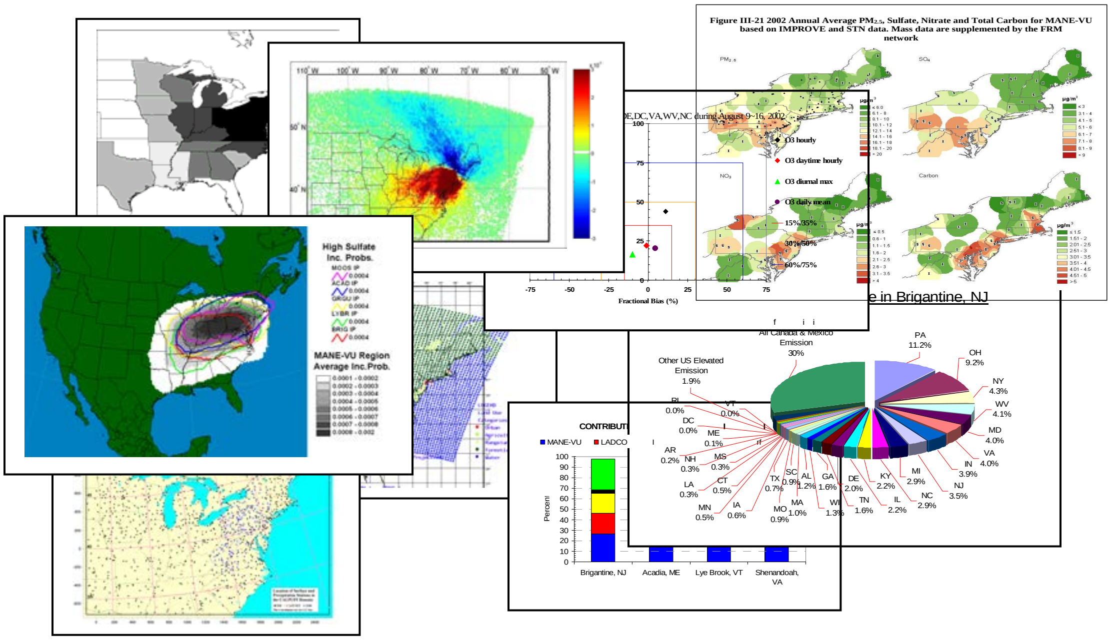
Contributions to Regional Haze in the Northeast and Mid-Atlantic United States

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

Prepared by NESCAUM
For the Mid-Atlantic/Northeast Visibility Union (MANE-VU)



August 2006

Members of NESCAUM Board

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Units, Symbols, Acronyms

Acronyms

AGL – Above Ground Level
ATAD – Atmospheric Transport and Diffusion Model
ARL – Air Resources Laboratory (NOAA)
BART – Best Available Retrofit Technology
BEIS – Biogenic Emission Inventory System
BRAVO - Big Bend Regional Aerosol and Visibility Observational study
CAIR – Clean Air Interstate Rule
CALMET – Meteorological model for developing input data for CALPUFF
CALPUFF – Lagrangian dispersion model developed by EarthTech, Inc.
CAMNET – Northeast Visibility Camera Network
CASTNet – Clean Air States and Trends Network
CEMS – Continuous Emissions Monitoring System
CENRAP – Central Regional Air Planning Association
CFR – Code of Federal Regulations
CMAQ – Community Multi-scale Air Quality Model
CMB – Chemical Mass Balance
CMU – Carnegie Mellon University
CTM – Chemical Transport Model
CWP – Clustered Weighted Probability
EDAS – Eta Data Assimilation System
EFIG – USEPA Emission Factor and Inventory Group
EGU – Electricity Generating Unit
EMAD – Emissions, Monitoring and Analysis Division
ERM – Environmental Resources Management, Inc.
FASTNET – Fast Aerosol Sensing and Tools for Natural aErosol Tracking
FNL – FiNaL run of the Global Data Assimilation System
FRM – Federal Reference Method
GIS – Geographic Information System
IMPROVE – Interagency Monitoring of Protected Visual Environments
IP – Incremental Probability
HAPS – Hazardous Air Pollutants
HYSPLIT – Hybrid Single-Particle Langrangian Integrated Trajectory model
MANE-VU – Mid-Atlantic/Northeast Visibility Union
MARAMA – Mid Atlantic Region Air Management Association
MDE – Maryland Department of the Environment
MDNR – Maryland Department of Natural Resources
MM5 – Fifth Generation Mesoscale Model
MOBILE – Mobile Source Emission Factor Model (USEPA)
MWRPO – Midwest Regional Planning Organization
NAAQS – National Ambient Air Quality Standards
NARSTO – North American Research Strategy for Tropospheric Ozone
NCAR – National Center for Atmospheric Research
NEI – National Emissions Inventory
NESCAUM – Northeast States for Coordinated Air Use Management
NET – National Emissions Trends (EPA)
NOAA – National Oceanic and Atmospheric Administration
NRC – National Research Council
NTI – National Toxics Inventory
NWS – National Weather Service
OAQPS – USEPA Office of Air Quality Planning and Standards

OAR – USEPA Office of Air and Radiation
OTC – Ozone Transport Commission
PCA – Principle Component Analysis
PM – Particulate Matter
PMF – Positive Matrix Factorization
PSCF – Potential Source Contribution Function
RAIN – Real Time Aerosol Intensive Network
REMSAD – Regulatory Modeling System for Aerosols and Deposition
RH – Relative Humidity
RPO – Regional Planning Organization
RTA – Residence Time Analysis
SIP – State Implementation Plan
SMOKE – Sparse Matrix Operator Kernel Emissions model
STN – Speciation Trends Network
TLD – Transport Layer Depth
TSC – Technical Support Committee
UMD – University of Maryland
UNMIX – Mathematical receptor model used for source attribution studies
USEPA – United States Environmental Protection Agency
USFS – United States Forest Service
USFWS – United States Fish and Wildlife Service
USNPS – United States National Park Service
VISTAS - Visibility Improvement State and Tribal Association of the Southeast
VT DEC – Vermont Department of Environmental Conservation
WRAP-Western Regional Air Partnership

Chemical Species

BC – Black Carbon
CM – coarse mass
CO – carbon monoxide
EC – elemental carbon
HC – hydrocarbons
H_2SO_4 – sulfuric acid
HNO_3 – nitric acid
NO_X – oxides of nitrogen (NO_2 and NO)
NO – nitric oxide
NO_2 – nitrogen dioxide
NO_3^- – nitrate
NH_3 – ammonia
NH_4 – ammonium
NH_4HSO_4 – ammonium bisulfate
$(NH_4)_2SO_4$ – ammonium sulfate
(NH_4NO_3) – ammonium nitrate
O_3 – ozone
OC – organic carbon
OMC – organic mass from carbon
$PM_{2.5}$ – particle matter up to 2.5 µm in size
PM_{10} – particle matter up to 10 µm in size
Se – selenium
SOA – secondary organic aerosol
SO_2 – sulfur dioxide
SO_4^{2-} – sulfate
VOC – volatile organic compounds

Symbols

b_{ext} – light extinction coefficient (Mm^{-1})
C_i – constant for wind sector i
d – distance
E x UP – emissions times upwind probability
f(RH) – relative humidity adjustment factor
I – impact
Q – annual emissions
R^2 – correlation coefficient

Units

Length
m – meter
µm – micrometer (0.000001m; 10^{-6}m)
km – kilometer (1,000 x m; 10^3 m)
Mm – Megameter (1,000,000 x m; 10^6 m)

Area
m^2 – square meter
km^2 – square kilometer

Volume
L – liter
m^3 – cubic meter

Concentration
µg/m^3 – micrograms per cubic meter
ng/m^3 – nanograms per cubic meter
ppb – parts per billion
ppm – parts per million

Scattering Efficiency
m^2/g – square meters per gram

Visibility
dv – deciview

Executive Summary

Regional haze State Implementation Plans (SIPs) due in December 2007 must include a contribution assessment and pollution apportionment analysis as part of the long-term emissions management strategy for meeting visibility improvement objectives in Class I areas subject to USEPA's 1999 Regional Haze Rule. The Mid-Atlantic/Northeast Visibility Union (MANE-VU) Technical Support Committee (TSC) has adopted a weight-of-evidence approach as a first step toward meeting these obligations and in an effort to better understand the causes of visibility impairment at Class I areas within the MANE-VU region. The weight-of-evidence approach relies on several independent methods for assessing the contribution of different emissions sources and geographic source regions to regional haze in the northeastern and mid-Atlantic portions of the United States.

The preliminary findings described in this report draw from the considerable body of work that has already been developed concerning the nature and extent of visibility impairment in the MANE-VU region. This work has produced a conceptual model of regional haze in which sulfate emerges as the most important single constituent of haze-forming fine particle pollution and the principle cause of visibility impairment across the region. Sulfate alone accounts for anywhere from one-half to two-thirds of total fine particle mass on the 20 percent haziest days at MANE-VU Class I sites. Even on the 20 percent clearest days, sulfate generally accounts for the largest fraction (40 percent or more) of total fine particle mass in the region. Sulfate has an even larger effect when one considers the differential visibility impacts of different particle constituents. It typically accounts for 70–82 percent of estimated particle-induced light extinction at northeastern and mid-Atlantic Class I sites.

While substantial visibility impairment is common across the region, it is most severe in the southern and western portions of MANE-VU that are closest to large power plant sources of sulfur dioxide (SO_2) emissions located in the Ohio River and Tennessee Valleys. Summertime visibility is driven almost exclusively by the presence or absence of regional sulfate, whereas wintertime visibility depends on a combination of regional *and* local influences coupled with local meteorological conditions (inversions) that can lead to the concentrated build-up of emissions from local sources.

These findings suggest that an effective emissions management approach would rely heavily on broad-based regional SO_2 control efforts in the eastern United States aimed at reducing summertime fine particulate matter ($PM_{2.5}$) concentrations. MANE-VU is investigating additional measures to reduce in-region emissions of SO_2 and organic carbon (OC), which is typically the next most important contributor to overall fine particle mass throughout the region. Nearby SO_2 reductions can help reduce wintertime PM concentrations, while OC reductions can help reduce total PM concentrations year-round. For areas with high wintertime PM levels, strategies aimed at reducing ambient levels of nitrogen oxides (NO_X) may also be effective.

Available monitoring data 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.

Given the dominant role of sulfate in the formation of regional haze in the Northeast and Mid-Atlantic region — and the likelihood that SO_2 reductions will therefore need to play a central role in achieving near-term visibility improvements — this report focuses on early efforts to assess the regional sulfate contribution to ambient fine particle levels experienced at the (primarily rural) MANE-VU Class I areas. The primary objective of this report is to identify and describe the suite of analytical tools and techniques that are presently available for: (1) understanding the causes of sulfate-driven visibility impairment at Class I areas in MANE-VU and nearby regions, as well as the relative contribution of various emissions sources and geographic source regions; and (2) describe how these tools and techniques will be applied in future MANE-VU SIP work.

The analytical and assessment tools discussed in this report include Eulerian (grid-based) source models, Lagrangian (air parcel-based) source dispersion models, as well as a variety of data analysis techniques that include source apportionment models, back trajectory calculations, and the use of monitoring and inventory data. A range of methodological approaches characterize these tools, which Table ES-1 summarizes. The tools rely on different data sources and entail varying degrees of sophistication and uncertainty. Thus, it is important to emphasize that these methods have been extensively reviewed, updated, and refined over the past year to ensure that the highest quality results are now available for the SIP development process. The overall coherence and consistency of results that emerges from application of these tools and techniques suggest that what is known about the causes of sulfate pollution in the MANE-VU region is sufficiently robust to provide a useful and appropriate basis for design of future control programs and for consultations between different regional organizations charged with planning for compliance with the Regional Haze Rule.

Figure ES-1 provides one illustration of the high degree of correspondence in the results. The figure shows rankings of state contributions to sulfate mass at Brigantine Wilderness Area in New Jersey derived from several of the techniques listed in Table ES-1.[1] There is substantial consistency across a variety of analysis methods using techniques based on disparate chemical, meteorological and physical principles. Taken together, these findings create a strong weight-of-evidence case for the preliminary identification of the most significant contributors to visibility impairment in the MANE-VU Class I areas.

Similar results for other sites demonstrate that highly simplified, empirical approaches for identifying source contributions are consistent with more sophisticated approaches. Therefore, a firm basis exists for addressing contributions to regional transport of sulfate, and the range of variability between these techniques suggests the precision of these estimates.

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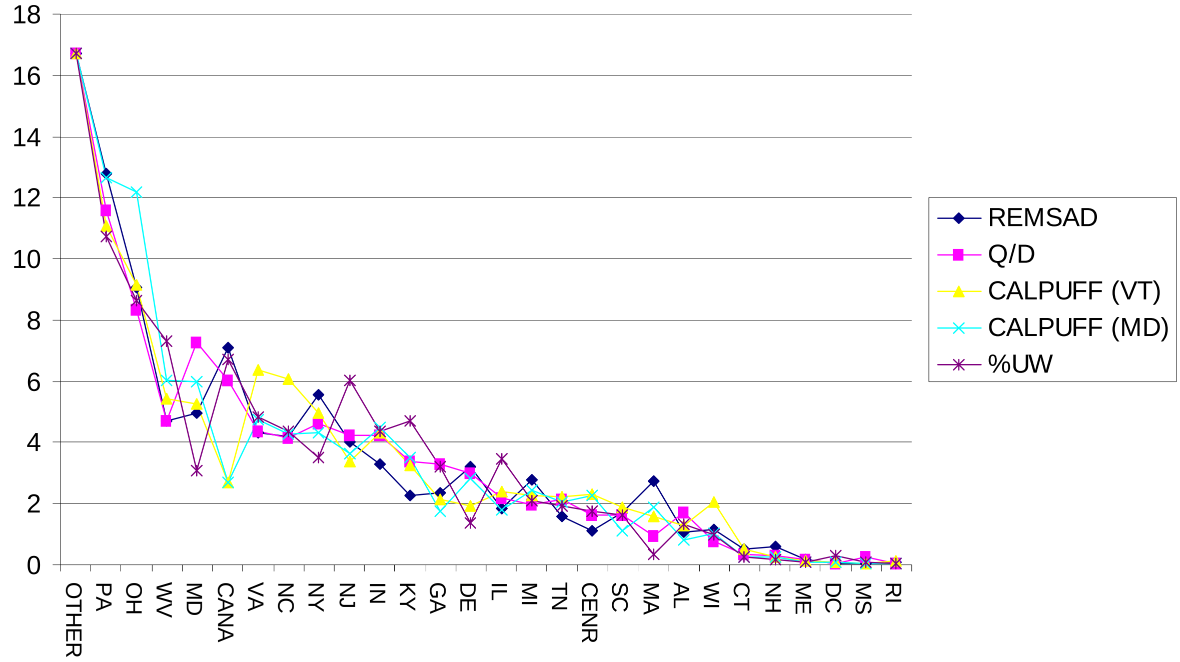
[1] As described in Chapter 8, REMSAD is the only analysis platform used to quantify “out of domain” contributions to sulfate. Thus, the REMSAD calculated contribution for the “out of domain” sources (17% at Brigantine, NJ) was used to calculate the percent contribution shown in Figure ES-1 for all other methods.

We have further aggregated these results by regional planning organization (RPO) using state-by-state sulfate mass contributions (in μg/m^3) derived by the REMSAD, CALPUFF, emissions/distance, and emissions times (×) upwind probability methods.[2] Figure ES-2 shows these results in terms of their absolute contribution (displayed within the bars shown in the graphic) and in terms of their proportional contribution relative to other RPOs.[1]

Table ES-1. Summary of technical approaches for attributing state contributions to observed sulfate in MANE-VU Class I areas.

Analytical technique	Approach
Emissions/distance	Empirical
Incremental probability	Lagrangian trajectory technique
Cluster-weighted probability	Lagrangian trajectory technique
Emissions × upwind probability	Empirical/trajectory hybrid
Source apportionment approaches	Receptor model/trajectory hybrid
REMSAD tagged species	Eulerian source model
CALPUFF with MM5-based meteorology	Lagrangian source dispersion model
CALPUFF with observation-based meteorology	Lagrangian source dispersion model

Figure ES-1. Comparison results using different techniques for ranking state contributions (in units of percent of in-domain contribution) to sulfate levels at Brigantine Wilderness Area, New Jersey.



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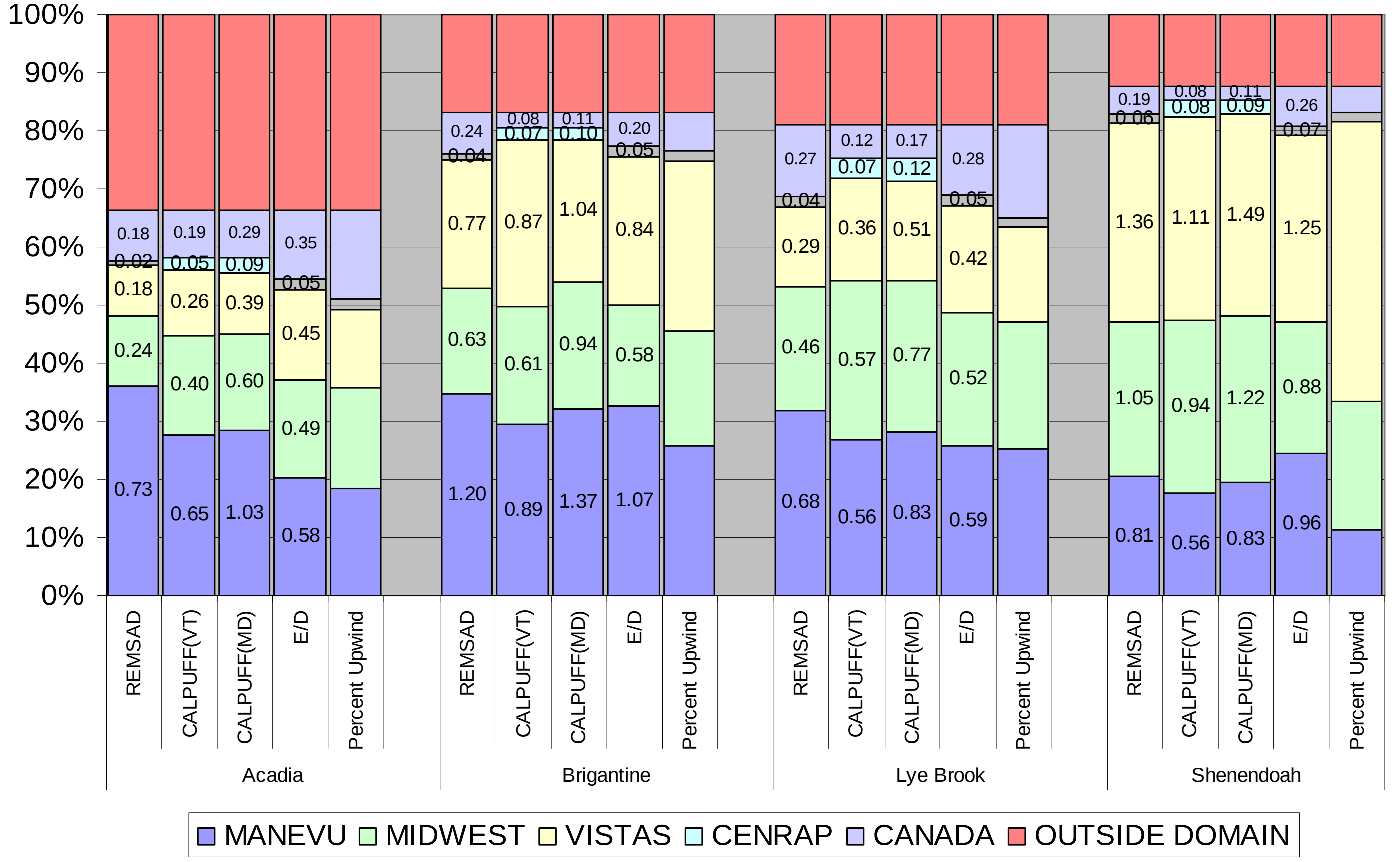
[2] See Chapter 4 for an explanation of how the emissions divided by distance technique is expressed as a sulfate mass concentration and the associated assumptions for the emissions × upwind probability method.

Notwithstanding small differences in precisely which states were included within each assessment technique, estimates obtained from averaging over the five quantitative assessment techniques indicate that MANE-VU states account for about 25-30 percent of the sulfate in the Acadia, Brigantine, and Lye Brook Class I areas. The Midwest RPO (MWRPO) and Visibility Improvement State and Tribal Association of the Southeast (VISTAS) states each account for about 15 percent of the total sulfate contribution at Acadia and about 25 percent each at Brigantine and Lye Brook. The Central states Regional Air Partnership (CENRAP) states, Canada, and an "out of domain" contribution add the remainder.[3] Although variation exists across estimates of contributions for different sites and using different techniques, the overall pattern is generally consistent.

Figure ES-2. Estimated RPO contributions to sulfate concentrations at Class I areas using different assessment techniques



Shenandoah National Park, Virginia, which is a VISTAS Class I area, has a somewhat reversed order of relative contributions. There, VISTAS and MWRPO states account for roughly 30 percent of overall sulfate each, with MANE-VU states contributing roughly 15-20 percent and CENRAP states, Canada and "out of domain" accounting for the remainder.

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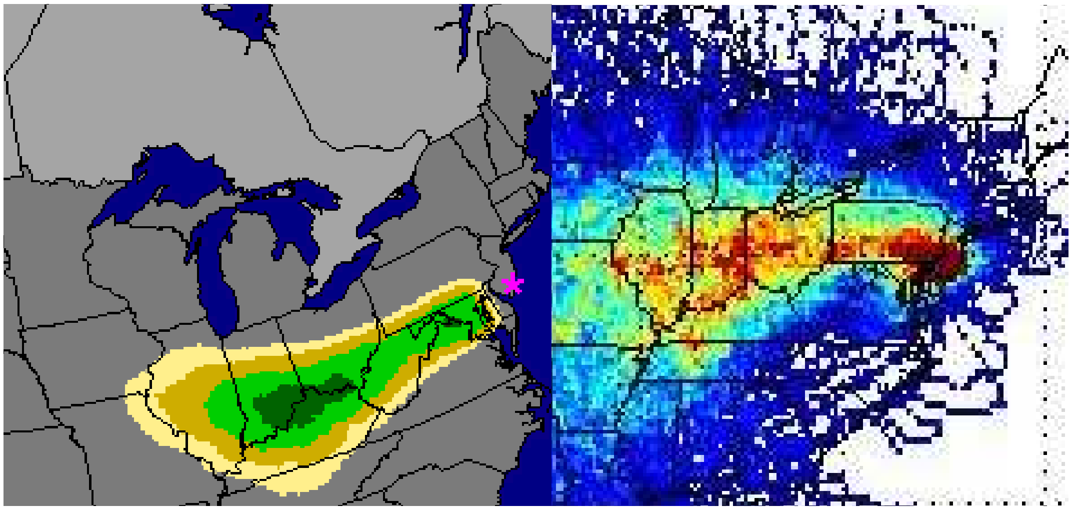
[3] Note here that the contribution representing out of domain sources was – in all cases – derived solely by the REMSAD platform and that this value has been applied to the other analysis techniques to provide a consistent estimate of the total contributions to sulfate pollution at each site.

Other qualitative analysis methods have been developed that reinforce the findings shown above. These include trajectory methods and source apportionment techniques. These receptor-based methods provide compelling support for the more quantitative attribution methods discussed previously. Figure ES-3 (left panel) shows the source region associated with a “coal combustion/secondary sulfate” source profile observed at Brigantine Wilderness in New Jersey and (right panel) the predominant meteorological pathways associated with the highest sulfate observations at Brigantine. The meteorological transport regime most common during high sulfate observations (shown on the right) directly connects the most likely source region with the receptor site (shown on the left), which reinforces the large quantitative contributions of source states determined for the Brigantine receptor in Chapter 8.

Finally, we note that while sulfate is the most important particle constituent for designing near-term control strategies, reductions in other local and distant pollutant emissions are important. Additional measures will be necessary in the long term to address public health impacts of ambient fine particle concentrations and to achieve long-term regional haze goals to restore pristine visibility conditions year-round in the nation’s Class I wilderness areas. This is especially true during winter months, when planners need to give particular consideration to reducing urban and mobile sources of NO_X and OC as well as sources of SO_2.

Figure ES-3. Geographic regions associated with “coal combustion/secondary sulfate” sources (left) and sulfate transport (right) for Brigantine Wilderness Area, NJ.



Note: This figure is the consistency of interpretation between the “coal-combustion/secondary sulfate” source region and receptor site shown in the left hand panel being directly connected by the predominant meteorological transport pathway on high observed sulfate days at Brigantine, shown in the right hand panel.

1. INTRODUCTION

The 1999 Regional Haze Rule (hereafter, the Haze Rule) requires States and Tribes to submit State Implementation Plans (SIPs) to the U.S. Environmental Protection Agency (USEPA) for approval by January 2008 at the latest. The haze SIPs must include a "contribution assessment" to identify those states or regions that may be influencing specially protected federal lands known as Federal Class I areas.[4] These states or regions would then be subject to the consultation provisions of the Haze Rule. The Haze Rule also requires a "pollution apportionment" analysis as part of the long-term emissions management strategy for each site.

In 2004, Congress harmonized the timeline for SIP submissions, including SIPs for meeting federal fine particulate matter ($PM_{2.5}$) and regional haze requirements.[5] One effect of this change is that the "regional planning SIP" or "committal SIP" — originally due one year after PM designations — will now be due along with all other SIP products in late 2007 or early 2008.

The Haze Rule originally would have applied a very low threshold test to determine whether a state would be part of a regional planning process, As a result of the congressional harmonization, however, the requirement for a contribution assessment is now, in effect, part of the "pollution apportionment" analysis used to determine which sources must be included in a long-term emissions management strategy. This is subject to a somewhat higher threshold of evidence since it forms the basis for judging whether long-term strategies are adequately addressing the causes of haze in protected areas.

To adequately determine the degree to which specific geographic regions or areas are contributing to visibility impairment at MANE-VU Class I areas, the MANE-VU Technical Support Committee (TSC) has adopted a weight-of-evidence approach that relies on several independent methods of attribution. These include Eulerian (grid-based) source models, Lagrangian (air pollution-based) source dispersion models, and a variety of data analysis techniques that include source apportionment models, back trajectory calculations, and the use of monitoring and inventory data.

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[4] 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.

[5] In the Omnibus Appropriations Act of 2004 [Consolidated Appropriations Act for Fiscal Year 2004, Pub. L. 108–199, January 23, 2004], Congress harmonized both designations and regional haze SIP deadlines. EPA promulgated $PM_{2.5}$ designations for all areas of each state on December 17, 2004. The Omnibus Appropriations Act provides that regional haze SIPs for each state as a whole are then due not later than three years after promulgation of the $PM_{2.5}$ designations. Thus, all components of the regional haze SIPs are now due no later than December 17, 2007 (three years after the USEPA issued the official designations). The USEPA has suggested informally that they will accept Regional Haze SIPs in April 2008 when $PM_{2.5}$ SIPs are due.

While we already know much about visibility impairment and its causes in the MANE-VU region (see NESCAUM, 2001; NESCAUM, 2002), significant gaps in understanding remain with respect to the organic component of fine particulate pollution. While we expect continuing research activities to substantially benefit future SIP efforts, the MANE-VU members have determined that sufficient information exists to design effective emission control strategies to meet visibility goals through 2018.

Reducing sulfur emissions offers particular leverage for achieving near-term visibility goals. It is the sulfate fraction of airborne fine particle matter that dominates light extinction on the 20 percent worst visibility days in the Northeast and Mid-Atlantic region. This is important because improving visibility on the 20 percent worst days is a near-term regulatory objective under the Regional Haze rule. In addition, many tools are available for assessing sulfate contributions. Therefore, this document focuses to a large extent on assessing sources and source regions for the sulfate fraction of haze-causing particles.

To lay a foundation for the analyses described in later chapters of this report, Chapter 2 provides a conceptual model of visibility impairment in the eastern United States. Chapter 3 presents a summary of available monitoring data and observations that we use to support the conceptual model and to validate models and data analyses. In fact, measured data — far from being used merely to support modeling analyses — serve as the primary basis for several of the receptor techniques presented in later chapters. There is thus no substitute for a robust monitoring network to understand the causes of fine particle pollution and visibility impairment.

Later chapters reinforce the notions introduced in Chapters 2 and 3 in using emission inventories (Chapter 4), receptor-based approaches including the use of back trajectories, trajectory clustering techniques and source apportionment models (Chapter 5), Eulerian chemical transport models (Chapter 6), and Lagrangian dispersion models (Chapter 7). We synthesize and interpret these various techniques in Chapter 8 and present conclusions in Chapter 9. We discuss technical aspects of the analyses in several of these later chapters in greater detail in a series of appendices.

As a general matter throughout this report, the focus is on assessing the contribution of all sources within broad geographical areas (i.e., whole states) whose combined emissions are likely to contribute to regional haze. As cited in Watson (2002), the National Research Council (NRC) has concluded that:

> (1) "…a program that focuses solely on determining the contribution of individual emission sources to visibility impairment is doomed to failure. Instead, strategies should be adopted that consider many sources simultaneously on a regional basis, although assessment of the effect of individual sources will remain important in some situations;" (2) "…there are (and will probably continue to be) considerable uncertainties in ascertaining a precise relationship between individual sources and the spatial pattern of regional haze;" and (3) "…the best approach for evaluating emission sources is a nested progression from simpler and more direct models to more complex and detailed methods" (Watson, 2002).

Watson (2002) goes on to point out that, “Part of the modeling conundrum is the focus of modeling efforts on demonstrating attainment rather than gaining a better understanding of the situation. Although USEPA emphasizes the construction of a conceptual model and evaluation of the weight of evidence in its introduction, the modeling details contained in the guidance are business as usual: seeking a quantitative comparison of present and future design values with a numerical goal.”

Consistent with the NRC’s admonition and USEPA’s stated desire to incorporate weight-of-evidence approaches to improve conceptual models, MANE-VU has attempted wherever possible to incorporate qualitative analyses in sensible ways so as to increase confidence in its quantitative estimates of the contribution of various emissions sources and source regions to regional haze.

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2. CONCEPTUAL MODEL OF REGIONAL HAZE IN THE MANE-VU REGION

Developing a conceptual model of 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 model based on the existing scientific literature concerning fine particles and their effect on visibility. This includes numerous review articles and reports on the subject. 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 focus.

Because the uncertainties involved in any particular method of analysis are usually large or ill-defined, it is preferable to develop visibility and fine particle management strategies with inputs from multiple analyses using multiple approaches. The MANE-VU TSC has adopted this approach, which leads to the diversity of data analyses and model results that follow. Later chapters of this report use original contributions and analyses developed by MANE-VU researchers to bolster and support the concepts presented in these introductory chapters. MANE-VU has combined the outputs and integrated them into a final conceptual model that explains the formation and transport mechanisms for fine particulate matter in the eastern United States.

2.1. Visibility Effects of Particulate Matter (PM)

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 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.

Visibility-impairing particle-light interactions are sensitive to the chemical composition of the particles involved, and also depend strongly on ambient relative humidity. Secondary particles, which form in the atmosphere through chemical reactions, tend to fall within a size range that is most effective at scattering visible light (NARSTO, 2003). These particles are generally smaller than one micrometer (μm) or one one-millionth of a meter. The particles that contribute most to visibility impairment also are a concern under the health-based National Ambient Air Quality Standard (NAAQS) for fine particulate matter, defined as including all particles with an aerodynamic diameter less than 2.5 μm ($PM_{2.5}$).

2.2. Chemical Composition of Particulate Matter in MANE-VU

Sulfate alone accounts for anywhere from one-half to two-thirds of total fine particle mass on the 20 percent haziest days at all MANE-VU Class I sites. Even on the 20 percent clearest days, sulfate generally accounts for the largest fraction (40 percent or more) of total fine particle mass in the region (NESCAUM, 2001). 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 haziest days. The fact that the contribution from organic carbon can be as high as 40 percent at the more rural sites on the 20 percent clearest days is likely indicative of the role played by organic emissions from vegetation (so-called "biogenic hydrocarbons" (HC)). 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. Nitrate plays a noticeably more important role at urban sites compared to northeastern and mid-Atlantic Class I locations, perhaps reflecting a greater contribution from vehicles and other urban pollution sources (NESCAUM, 2001).

Almost all particle sulfate originates from sulfur dioxide (SO_2) oxidation and typically associates with ammonium (NH_4) in the form of ammonium sulfate ($(NH_4)_2SO_4$), 95 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 on the clearest and haziest days at northeastern and mid-Atlantic Class I sites. 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). We discuss this further in the next section of this chapter.

Some of the dominant components of total fine particle mass have an even larger effect when considering the differential visibility impacts of different particle species. Sulfate typically accounts for over 70 percent of estimated particle-induced light extinction at northeastern and mid-Atlantic Class I sites. Organic carbon continues to be the second most important contributor to particle-induced light extinction at rural sites on the most impaired days, but slips to third behind nitrate in Washington, DC (NESCAUM, 2001).

2.3. Geographic Considerations and Attribution of PM/Haze Contributors

In the East, 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 Northeast and Mid-Atlantic region (NESCAUM, 2001).

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 the Haze Rule in the Northeast and Mid-Atlantic region (NESCAUM, 2001).

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 (Chapter 10, NARSTO, 2003) using two different mathematical models, UNMIX and Positive Matrix Factorization (PMF). (We describe these models in greater detail in Chapter 5 and Appendix B.) This analysis provides additional insight concerning sources of fine particle pollution in urban areas of the densely populated coastal corridor between Washington D.C. 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 near-by 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).

While these statistics provide some preliminary context for attributing responsibility for the region’s particulate matter and visibility problems, they say nothing about the relative efficiency of a state’s or region’s emissions in causing or contributing to the problem. It is clear that distance from the emissions source matters. Local, near-by sources are exceedingly important and sources within about 200 kilometers (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 and Tennessee River Valleys. These areas feature large coal-burning power stations, steel mills, and other large emissions sources. Average 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. Studies also frequently associated other types of industrial pollutants with known source areas. 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 National Park Service analysis determined that Ohio, Virginia, West Virginia, Pennsylvania, and Kentucky comprise the top five of thirteen 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 summary, the National Park Service found that emission sources located within a 200 kilometer (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 from the north-northeast to the east.[6] 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).

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

We note that several MANE-VU states may themselves be contributing to fine particle mass concentrations observed at Shenandoah. According to the Park Service analysis, sources in Pennsylvania contribute on the order of 10 percent of observed ambient sulfate mass at the park, while sources in Maryland, New York and Delaware contribute 3.5, 1.7 and 0.5 percent respectively (USNPS, 2003).

2.4. 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 the MANE-VU domain extends inland as far as the Pennsylvania and Ohio border, the majority of Class I areas in MANE-VU cluster along the East Coast and thus typically show strong seasonal influences. Maximum $PM_{2.5}$ concentrations occur during the summer over most of the Northeast, with observed summer values for rural areas in the region, on average, twice those of winter. Winter nitrate concentrations, however, 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 models that explain elevated regional $PM_{2.5}$ peak concentrations in the summer differ significantly from models 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 and the accumulation of airborne sulfate (via atmospheric oxidation of SO_2) through 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 the OTR is somewhat less with ranges from 25 to 40% and that the long range transport component of PM 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, sulfate, 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 usually the single largest source of selenium (Se) and other heavy metal trace elements (USEPA, 2003).

Visually, hazy summer days in the Northeast can appear quite different from hazy winter days. The milky, uniform visibility impairment shown in Figure 2-1 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 2-2. 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 overall light extinction during the winter months (NESCAUM, 2001).

Figure 2-1. Summer time at Mt Washington

Clean Day **Typical Haze Event**

Figure 2-2. Wintertime in Boston

Clean Day **Typical Haze Event**

2.5. Implications for control strategies

A 2003 assessment of fine particulate matter by NARSTO[7] notes that, “[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

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[7] 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/.

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, the fact that 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, 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 northeastern and southeastern 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 concentrations, while OC reductions can help reduce overall PM concentrations year-round. For areas with high wintertime PM 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) that concluded 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 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. At that point, further sulfate reductions would once again be 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).

2.6. Summary

The presence of fine particulate matter in ambient air significantly 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.

The presence or absence of regional sulfate almost exclusively drives summer visibility impairment, 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, as well as NO_X and OC (NARSTO, 2003).

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3. OVERVIEW OF MONITORING RESULTS

SIP developers use monitoring data in three important ways to support regional haze SIP activities. Section 3.1 presents measurements from the IMPROVE network needed in establishing SIP requirements. Following USEPA guidance (USEPA, 2003a; USEPA, 2003b), we use these data to preview the uniform progress goals that SIP developers must consider for each Class I area.

Section 3.2 reviews a recent NESCAUM report (NESCAUM, 2004b) to demonstrate how available monitoring data support and validate the conceptual model presented in Chapter 2.

Section 3.3 presents early results from the MANE-VU Real-Time Aerosol Intensive Network (RAIN). These suggest some of the ways MANE-VU is preparing to extend and improve understanding of visibility issues across the region. We anticipate this aspect of the MANE-VU monitoring strategy to be critical for future status reports and SIP updates.

3.1. Baseline Conditions

The 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 3-1 presents the five-year average[8] of the 20 percent worst day mass concentrations 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.[9] Table 3-2 gives the corresponding worst 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, USEPA released two documents in the fall of 2003 outlining recommended procedures (USEPA 2003a; USEPA 2003b). These proposed methods were used, along with the data in Table 3-1 and Table 3-2 to create Table 3-3, which provides detail on the 20 percent worst conditions for the six Class 1 areas.

The first column of data in the Table 3-3 gives the default natural background levels for the worst visibility days at these six sites. Although debate continues with regard to some assumptions underlying the USEPA default approach for estimating natural background visibility conditions, MANE-VU has decided to use this approach, at least initially, for 2008 SIP planning purposes (NESCAUM, 2004a). 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-

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

[9] 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.

2004). Using these baseline and natural background estimates, we derive the uniform rate of progress shown in the third column.[10] The final column displays the interim 2018 progress goal based on 14 years of improvement at the uniform rate.

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

20% Worst-day fine mass (μg/m^3) / % contribution to fine mass					
Site	SO_4	NO_3	OC	EC	Soil
Acadia	6.3 / 60%	0.8 / 8%	2.5 / 23%	0.4 / 4%	0.5 / 5%
Brigantine	11.5 / 59%	1.8 / 9%	4.5 / 23%	0.7 / 4%	1.0 / 5%
Great Gulf	7.3 / 63%	0.3 / 3%	2.9 / 25%	0.4 / 3%	0.6 / 5%
Lye Brook	8.5 / 62%	1.1 / 8%	3.0 / 22%	0.5 / 3%	0.6 / 5%
Moosehorn	5.7 / 58%	0.7 / 7%	2.6 / 27%	0.4 / 4%	0.4 / 4%
Shenandoah	13.2 / 72%	0.7 / 4%	3.3 / 18%	0.6 / 3%	0.7 / 4%

Table 3-2. Particle extinction and percent contribution for 20% worst days

20% Worst-day particle extinction (Mm^{-1}) / % contribution to extinction						
Site	SO_4	NO_3	OC	EC	Soil	CM
Acadia	66.0 / 73%	8.1 / 9%	10.1 / 11%	4.4 / 5%	0.5 / 1%	1.8 / 2%
Brigantine	106.2 / 69%	16.1 / 10%	18.3 / 12%	7.1 / 5%	1.0 / 1%	5.2 / 4%
Great Gulf	66.5 / 76%	3.0 / 3%	10.6 / 13%	3.8 / 4%	0.5 / 1%	2.9 / 3%
Lye Brook	76.7 / 73%	9.3 / 9%	12.1 / 11%	4.7 / 5%	0.7 / 1%	1.8 / 2%
Moosehorn	56.1 / 70%	6.3 / 8%	10.5/ 13%	4.4 / 5%	0.4 / 0%	2.1 / 3%
Shenandoah	132.5 / 82%	5.8 / 4%	13.2 / 8%	5.7 / 4%	0.8 / 0%	2.6 / 2%

Table 3-3. Natural background and baseline calculations for select Class I areas

Site	Natural Background (dv)	Baseline 2000-04 (dv)	Uniform Rate (dv/year)	Interim Progress Goal 2018 (dv)
Acadia	11.45	22.34	0.18	19.80
Brigantine	11.28	27.60	0.27	23.97
Great Gulf	11.30	22.25	0.18	19.69
Lye Brook	11.25	23.70	0.21	20.80
Moosehorn	11.36	21.18	0.16	18.89
Shenandoah	11.27	27.88	0.28	24.00

The regional haze rule calls for steady improvement of visibility on the 20 percent worst visibility days. States are to consider this uniform rate of progress, and if reasonable measures can be identified to meet or exceed this rate while ensuring no degradation of visibility on the best days, then it should be adopted as a Federal Class I

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[10] 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.

area's *reasonable* progress goal. A number of instructive analyses are presented below using each area's uniform progress goal as an example, but these should not be interpreted as constituting MANE-VU recommendations on reasonable progress goals.

As a practical means of analyzing uniform progress goals, we have examined the components of observed fine particle pollution that substantially contribute to visibility degradation. This analysis shows that certain species dominate the extinction budget while others play virtually no role on the worst haze days.

As demonstrated in Table 3-2, 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 about eight to one 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.

One approach to designing control strategies for achieving reasonable progress goals is to reduce all components of $PM_{2.5}$ in equal proportion. Achieving the 2018 uniform progress goals (expressed in Mm^{-1} in the second column of Table 3-4) requires between a 29 and 36 percent reduction in each component of the six haze components of fine particle extinction if their relative percent contributions to the current worst baseline conditions are kept constant (see the third column of Table 3-4). Given the dominant role of sulfate and nitrate, however, and the difficulty in obtaining 29 to 36 percent reductions in some of the other categories such as soil or course mass, sulfate- and nitrate-based control programs are likely to offer more reasonable emission reduction opportunities.

Table 3-4. Percent particle B_{ext} reduction needed to meet uniform progress[11]

Site	Particle Extinction Decrease (Mm^{-1})	Uniform Reduction (%)	Sulfate/Nitrate Reduction (%)	OC/EC Reduction (%)
Acadia	27.7	31	38	194
Brigantine	55.3	36	46	218
Great Gulf	30.6	33	42	195
Lye Brook	35.4	34	41	210
Moosehorn	23.4	29	38	158
Shenandoah	57.1	36	42	303

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[11] We derive the information in this table from the results of Table 3-3. First, we converted the baseline and interim goal levels from dv to Mm^{-1} units, thus avoiding the logarithmic nature embedded into the deciview calculations. The first column of the table gives the difference between baseline and interim goal. The ratio of this difference to the baseline yields the uniform rate of reduction tabulated in the second column. We generate the paired species reduction percentages by using the wet and dry aerosol extinction coefficients. We determine f(RH) values by dividing the five-year B_{ext} average by the dry extinction coefficient, giving a weighted average value of the f(RH) during the worst 20% of days. Similarly, in Table 3-5, we calculate mass values using the relative contributions of the species to be reduced and their wet and dry efficiencies.

The fourth column of Table 3-4 displays the results if a sulfate and nitrate focused control approach were taken to meet uniform progress goals. For these two inorganic species, a greater reduction would be necessary on the 20 percent worst days if the other four components showed no change relative to baseline levels. The last column shows that the contribution of the carbonaceous species is too small to meet the entire required 2018 progress goal on its own (i.e. the percent reduction is greater than 100) if a carbon-only control approach were attempted.

Since it is easier to understand the implications of requisite mass reductions, rather than extinction, Table 3-5 tabulates the corresponding mass changes required for meeting uniform progress goals on the 20 percent worst days. On an absolute mass basis, the changes across sites are more varied than they are when viewed from a percentage change perspective. That in part is a function of the relative pollution levels at each site, in addition to the logarithmic nature of the deciview (dv). This table (along with Table 3-6) can aid planners to gauge the potential impact that meeting uniform progress goals under the Regional Haze program will have on regional fine particle mass levels.

Table 3-5. Mass reductions required on 20% worst days based on extinction estimates in Table 3-4

	20% Worst Day Mass Reduction (μg/m^3)							
	Uniform Percent Change All Species				Only Inorganic		Only Carbonaceous	
Site	SO_4	NO_3	OC	EC	SO_4	NO_3	OC	EC
Acadia	1.95	0.25	0.76	0.13	2.38	0.31	4.80	0.85
Brigantine	4.14	0.65	1.64	0.26	5.22	0.82	9.92	1.56
Great Gulf	2.42	0.11	0.97	0.13	3.06	0.14	5.74	0.76
Lye Brook	2.85	0.36	1.02	0.16	3.49	0.44	6.36	1.00
Moosehorn	1.68	0.20	0.77	0.13	2.14	0.26	4.12	0.69
Shenandoah	4.78	0.24	1.19	0.21	5.57	0.28	9.94	1.74

Table 3-6 provides an estimate of mass decreases that might be expected on an average day. It assumes using either a uniform rate of change in *all* species, or a uniform rate of change in the *sulfate and nitrate* component of fine particulate, to achieve the progress toward the 2018 goals, respectively. These values are likely a lower bound to the annual average change at Class I areas anticipated from current conditions to 2018 as they are based on the assumption that on the best days, no change occurs and the percent reduction on the middle days is half of what is predicted on the worst.[12]

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[12] We derived the values tabulated in Figure 3-6 as follows: We multiplied half of the percentage change expected on the worst 20% of days by the average mass concentration of each species for the middle 20% of days. Note that if we apply a 25% reduction on the cleaner remaining quintile and 75% reduction on the dirtier remaining quintile, the annual average reduction would presumably be greater than that on the middle days given the skew in the distribution of all days. For example, in the inorganic-only case at Acadia, the average of the worst 20% change and best 20% is (2.69 + 0)/2 or 1.35 μg/m^3, which is nearly four times greater than the middle day. Further, given the large reduction on the worst days, it is reasonable to expect some small improvement on the best days.

Table 3-6. Estimated Mass Reduction on an Average Day

	Estimated Average Day Mass Reduction ($\mu g/m^3$)					
	Uniform Percent Change All Species				Only Inorganic	
Site	SO_4	NO_3	OC	EC	SO_4	NO_3
Acadia	0.25	0.05	0.16	0.02	0.31	0.06
Brigantine	0.80	0.19	0.38	0.08	1.01	0.25
Great Gulf	0.28	0.04	0.19	0.03	0.36	0.05
Lye Brook	0.29	0.07	0.17	0.03	0.36	0.09
Moosehorn	0.25	0.05	0.19	0.03	0.32	0.06
Shenandoah	0.79	0.24	0.28	0.05	0.92	0.28

3.1.1. Preview of revised IMPROVE Algorithm for aerosol extinction

Recently, the IMPROVE Steering Committee accepted an alternative approach for calculating visibility metrics based on measured aerosol concentrations. The new algorithm improves the correspondence between the reconstructed extinction and directly measured light scattering at the extremes of the visibility range. These extremes form the basis for determining the uniform progress “glide path.”

The new equation revises or adds to the original version. The most significant changes include:

- revision of the dry aerosol extinction coefficients for sulfate, nitrate and organic carbon,
- splitting sulfate, nitrate and organic mass into small and large size fractions based on total species mass,
- revised f(RH) curves for inorganic species,
- inclusion of sea salt mass and associated f(RH) growth factor,
- use of a *site-specific* Rayleigh scattering term, and
- revision of the organic mass multiplier.

The VIEWS website provides the revised dataset for all IMPROVE data, allowing the calculation of the baseline period with the new algorithm. Natural background calculation methods that mirror many of the changes adopted as an alternative for baseline calculations have been suggested; however, none have been formally adopted by the IMPROVE Steering Committee at this time.

As a first step toward assessing the implications of the algorithm revisions, we compare the baseline visibility levels from the old and new approaches. The new calculation approach results in between one and two deciview increase in the 20 percent worst visibility conditions during the baseline period for the six sites considered. Extinction changes are observed for all components, with increases ranging from 6 to 42 percent depending on species. The greatest overall percentage change occurs for organic carbon and the least for fine soil. Changes in the baseline 20 percent best days were much less with the absolute contribution of a component to visibility degradation increasing in some cases and decreasing in others. On average, the values decrease by 0.1 deciview. Table 3-7 and Table 3-8 summarize the species-specific changes for worst and best days' aerosol extinction.

Table 3-7. Aerosol extinction by specie for 20% worst days

20% worst-day particle extinction (Mm^{-1}) New Algorithm / Old Algorithm							
Site	SO_4	NO_3	OC	EC	Soil	Coarse	Salt
Acadia	76.4 / 66	8.6 / 8.1	12.5 / 10.1	4.8 / 4.4	0.6 / 0.5	2.1 / 1.8	1.4 / 0
Brigantine	134.2 / 106.2	18.1 / 16.1	25.9 / 18.3	7.9 / 7.1	1.0 / 1.0	6.5 / 5.2	0.7 / 0
Great Gulf	79.6 / 66.5	3.4 / 3.0	14.8 / 10.6	4.3 / 3.8	0.6 / 0.5	3.1 / 2.9	0.1 / 0
Lye Brook	94.4 / 76.7	10 / 9.3	17.1 / 12.1	5.3 / 4.7	0.7 / 0.7	2.1 / 1.8	0.1 / 0
Moosehorn	64 / 56.1	7 / 6.3	13.4 / 10.5	5.1 / 4.4	0.4 / 0.4	2.5 / 2.1	1.1 / 0
Shenandoah	169.6 / 132.5	7.9 / 5.8	18.2 / 13.2	6.5 / 5.7	0.8 / 0.8	3.0 / 2.6	0.1 / 0

Table 3-8. Aerosol extinction by specie for 20% best days

20% best-day particle extinction (Mm^{-1}) New Algorithm / Old Algorithm							
Site	SO_4	NO_3	OC	EC	Soil	Coarse	Salt
Acadia	6.8 / 7.4	1.1 / 1.2	2.3 / 2.4	0.9 / 0.9	0.1 / 0.1	0.7 / 0.7	0.4 / 0
Brigantine	5.7 / 6.2	1.0 / 1.1	2.0 / 2.1	0.9 / 0.9	0.1 / 0.1	0.9 / 0.7	0.2 / 0
Great Gulf	5.7 / 6.2	1.0 / 1.1	2.0 / 2.1	0.9 / 0.9	0.1 / 0.1	0.9 / 0.7	0.2 / 0
Lye Brook	4.5 / 5.0	1.2 / 1.2	1.3 / 1.4	0.6 / 0.6	0.1 / 0.1	0.5 / 0.5	0.0 / 0
Moosehorn	6.8 / 7.3	1.0 / 1.2	3.1 / 3.1	1.0 / 1.0	0.1 / 0.1	1.1 / 1.1	0.3 / 0
Shenandoah	11.4 / 12.8	4.2 / 4.4	2.9 / 3.0	1.6 / 1.6	0.2 / 0.2	1.1 / 1.1	0.1 / 0

Figure 3-1and Figure 3-2 graphically compare the old and new algorithm for six sites. The left-hand side of the figures presents the old contribution of aerosol extinction while the right-hand side shows the new calculations. Relatively small differences are apparent, with slight relative decreases in sulfate contribution offset by small increases in nitrate, organic carbon and the addition of sea salt.

The potential impact of these changes on the uniform rate of progress slope cannot be determined at this time, since revisions in natural background calculations remain incomplete. A preliminary assessment, however, suggests that natural background estimates for MANE-VU may increase by about 10 percent. This translates to a change of just over one deciview. This estimate combined with the average increase of 1.5 deciview in baseline conditions would not likely change the slope of the uniform progress curve in any significant way. Nonetheless, the actual mass reductions required could change given the logarithmic nature of the haze index, where marginal mass changes are larger at higher deciview levels. It is not a straightforward exercise to estimate the potential effect of such changes given the increased complexity of the new algorithm relative to the old equation.

Figure 3-1. Comparison of Old and New Algorithms for Baseline Worst Days

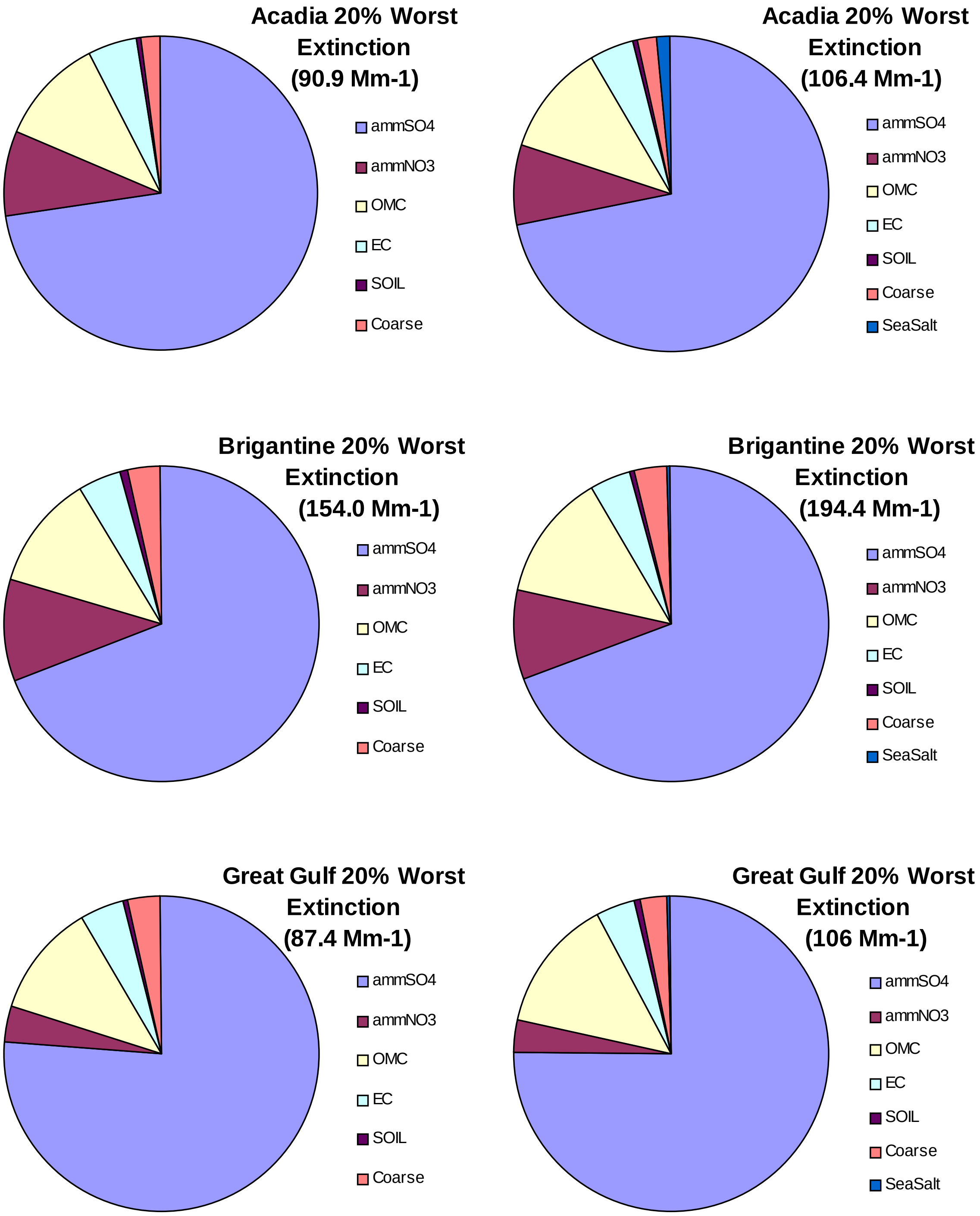
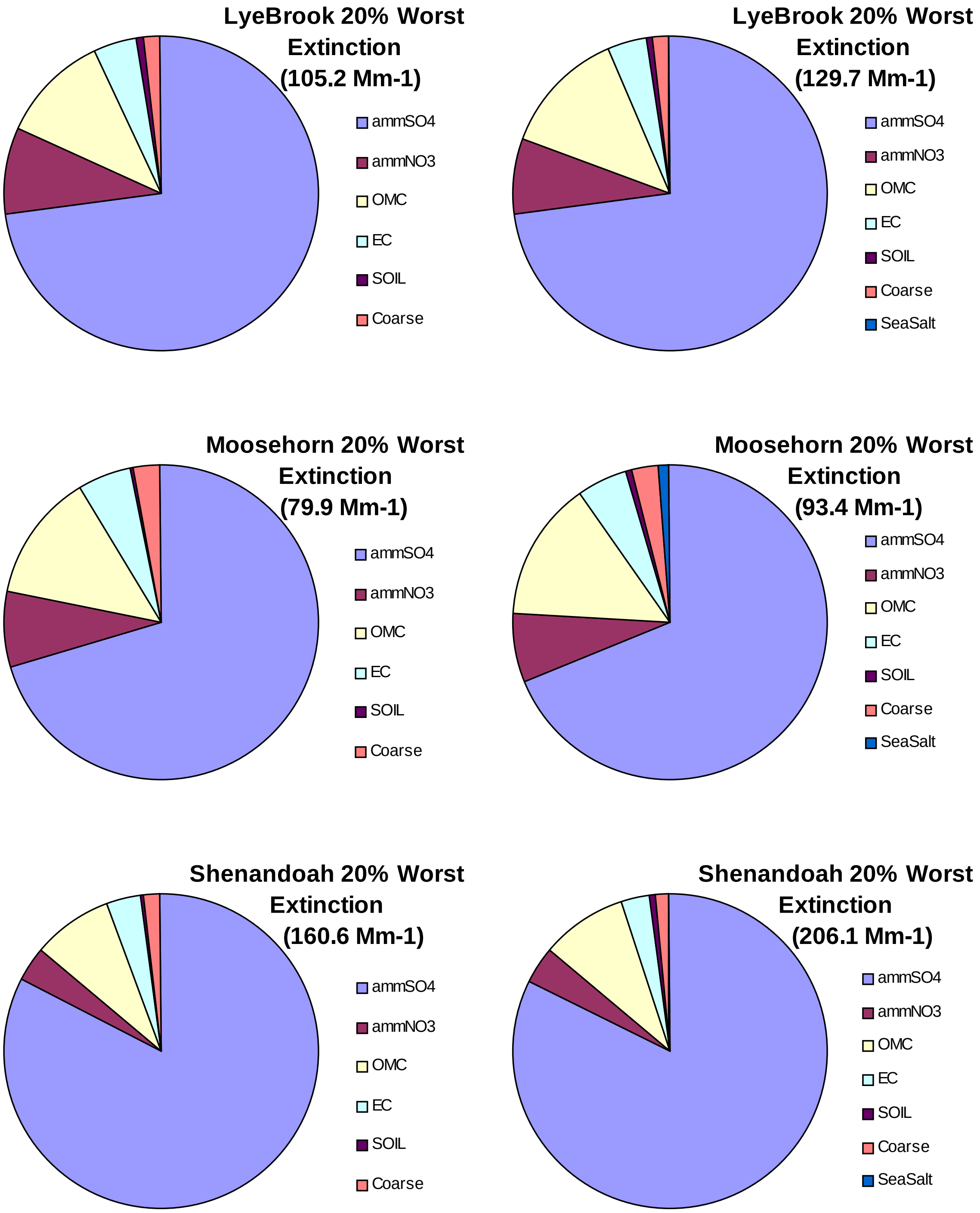


Figure 3-2. Comparison of Old and New Algorithms for Baseline Worst Days



LyeBrook 20% Worst Extinction (105.2 Mm-1)

LyeBrook 20% Worst Extinction (129.7 Mm-1)

Moosehorn 20% Worst Extinction (79.9 Mm-1)

Moosehorn 20% Worst Extinction (93.4 Mm-1)

Shenandoah 20% Worst Extinction (160.6 Mm-1)

Shenandoah 20% Worst Extinction (206.1 Mm-1)

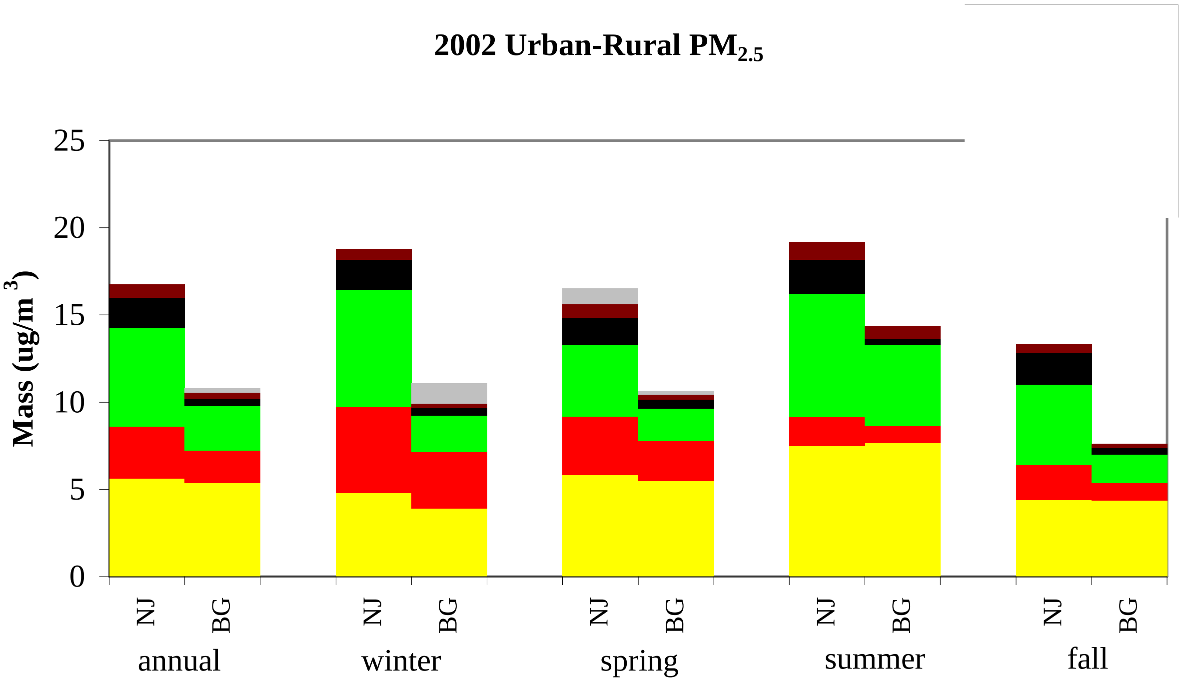
3.2. 2002 Monitoring Data

The recent MANE-VU report "2002 Year in Review" (NESCAUM, 2004b) provides a comprehensive review of monitoring data available to support SIP development in the MANE-VU region, including data on fine particle composition, as well as temporal and spatial distributions. The data in this study support the conceptual model in several important ways. They show that: (1) the single largest component of fine particle mass is sulfate; (2) the largest sulfate-generating emissions sources that affect the MANE-VU region lie to the south and west of the region; (3) fine particle concentrations are bi-modal with peaks in the summer and winter; and (4) summer and winter peak concentrations are generally caused by different chemical and physical processes in the atmosphere (i.e., summer peaks are strongly related to regional sulfate transport whereas winter peaks result from the sum of regionally-generated sulfate and locally generated sulfate, as well as organics and nitrate that build up during local stagnation events).

3.2.1. Sulfate

Data from several monitoring programs indicate that sulfate (on an annual basis) is the single largest component of fine particle mass in the MANE-VU region. Figure 3-3 displays sample data from two Speciation Trends Network (STN) sites in New Jersey. This shows that sulfate accounts for roughly half of fine particle mass on an annual average basis at background sites and about a third at the urban site. During summer, sulfate comprises over half the fine particle mass at rural background sites and two-fifths of fine particle mass at the urban site. When considering the different light-extinguishing properties of various fine particle constituents, sulfate is responsible for an even greater fraction of visibility impairment. It accounts for between three-quarters and four-fifths of overall light extinction on the 20 percent worst- visibility days (Table 3-2).

Figure 3-3. New Jersey Urban Area Compared to an Upwind Background Site



3.2.2. Southwest-Northeast Gradient

Figure 3-4 shows that $PM_{2.5}$ mass declines fairly steadily along a southwest to northeast transect of MANE-VU. This decline is consistent with the existence of large fine particle emissions sources (both primary and secondary) to the south and west of the MANE-VU region.

This trend in $PM_{2.5}$ mass is primarily due to a marked southwest-to-northeast gradient in ambient sulfate concentrations during three seasons of the year as illustrated in Figure 3-5. Wintertime concentrations, by contrast, are far more uniform across the entire region. Figure 3-6 shows that on an annual basis, both total PM and sulfate mass are highest in the southwestern portions of MANE-VU (note the different scales for each pollutant). High concentrations of nitrate and organic particle constituents, which play a role in localized wintertime PM episodes, tend to be clustered along the northeastern urban corridor and in other large urban centers.

Sulfate is a secondary pollutant, meaning that it forms in the atmosphere from precursor emissions. The formation of sulfate from SO_2 emissions requires time in an oxidizing environment. Therefore, it is likely that a substantial portion of the sulfate observed in the MANE-VU region is from sulfur emitted from south and west of the region. Modeled meteorological (trajectory) data presented in Chapter 5 support this conclusion by showing that the dominant wind direction over the MANE-VU region during periods of high sulfate concentrations is from the southwest.

Figure 3-4. MANE-VU FRM $PM_{2.5}$ statistics along a southwest to northeast axis

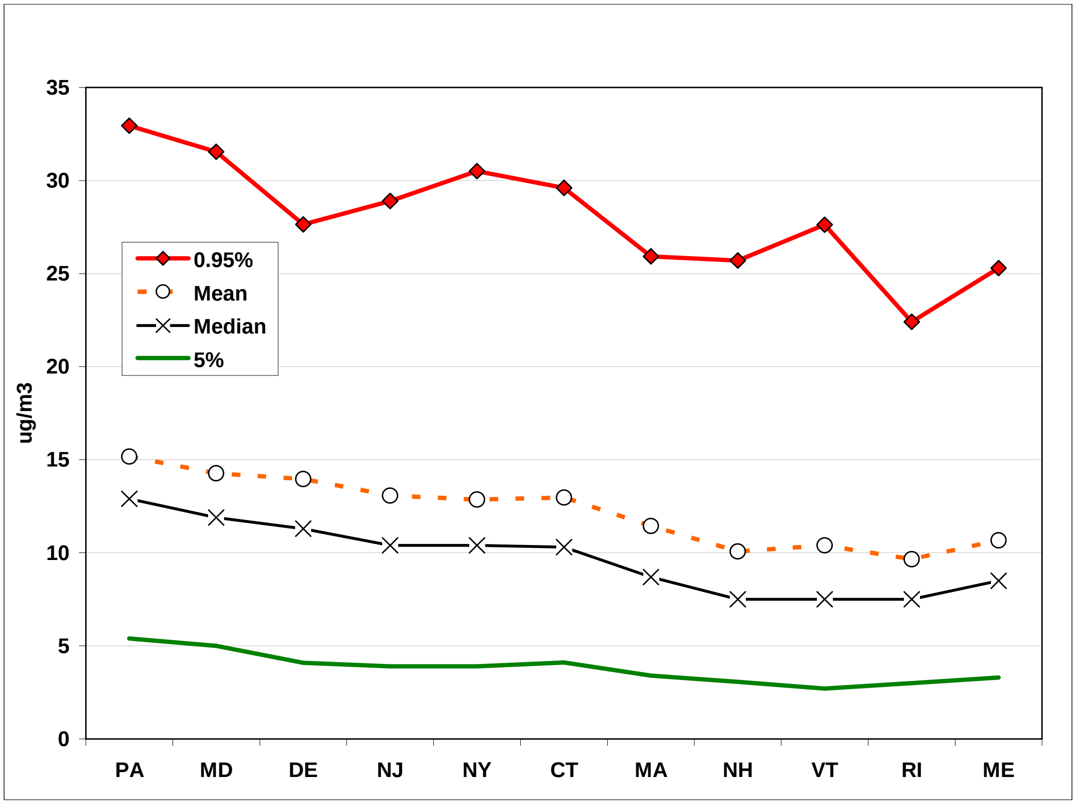


Figure 3-5. 2002 Seasonal average SO4 based on IMPROVE and STN data

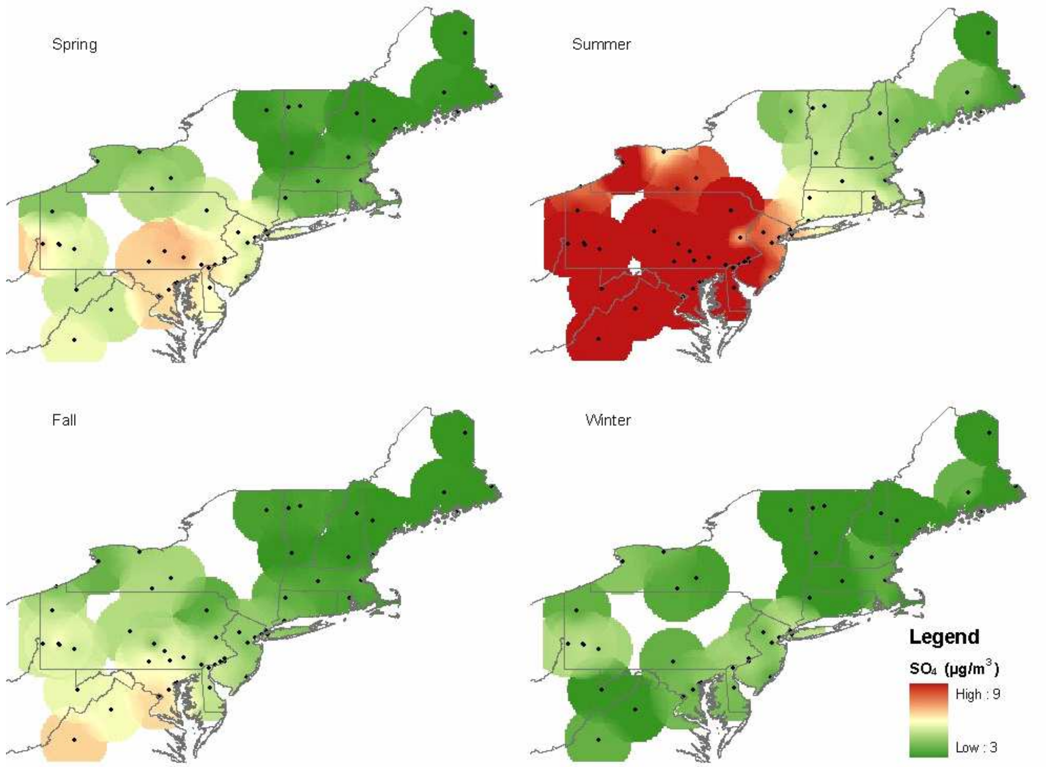
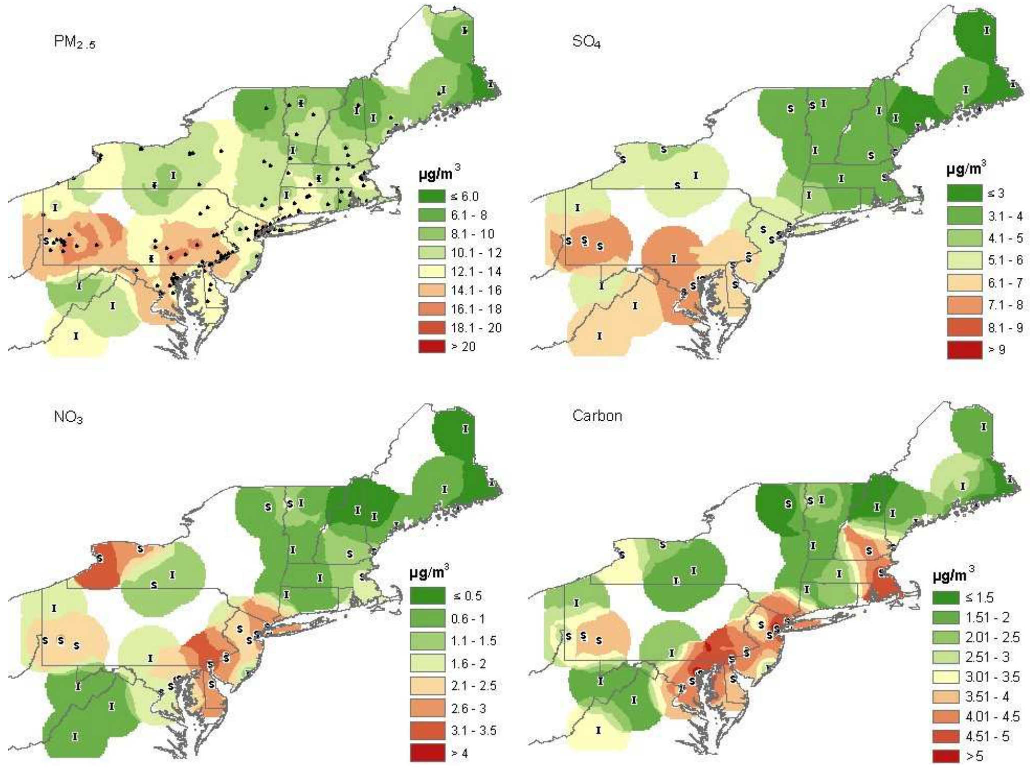


Figure 3-6. 2002 Annual average $PM_{2.5}$, sulfate, nitrate and total carbon for MANE-VU based on IMPROVE and STN data. Mass data are supplemented by the FRM network.



3.2.3. Seasonality

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. This bimodal seasonal distribution of peak values is readily apparent in Figure 3-7. 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 3-7. Moving 60-day average of fine aerosol mass concentrations based on long-term data from two northeastern cities

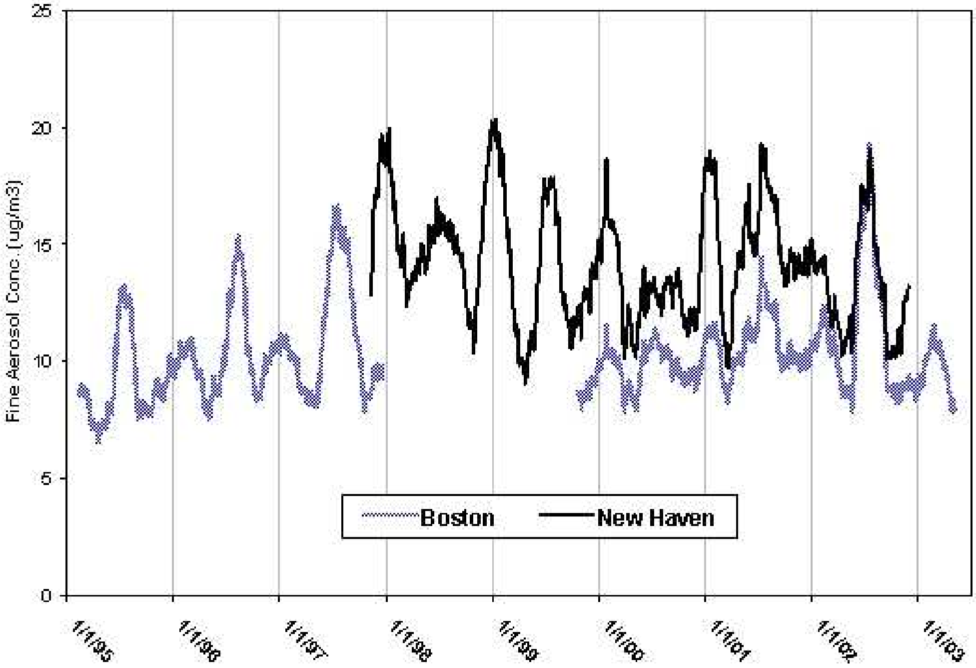
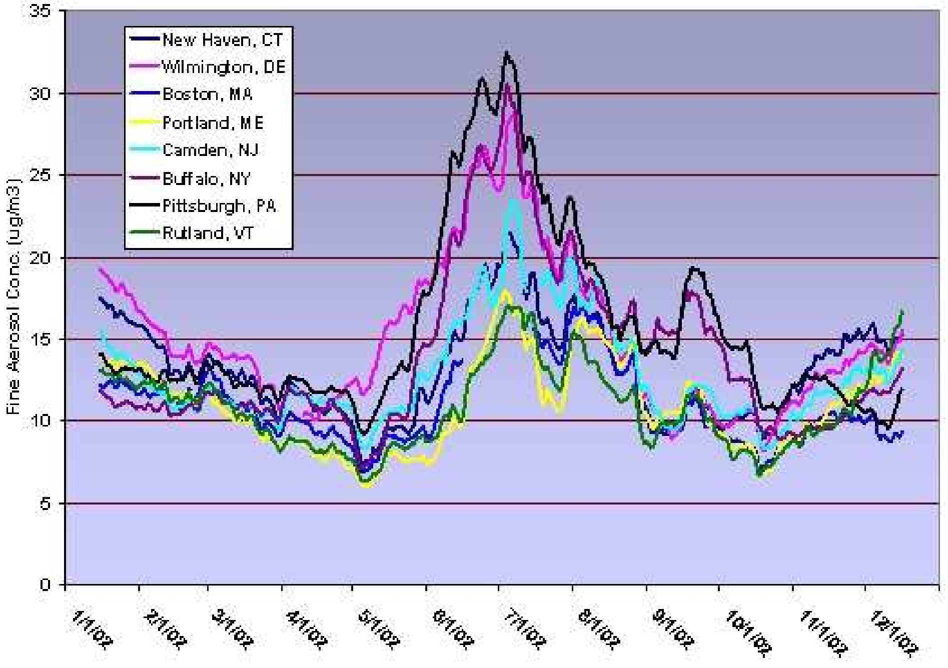


Figure 3-8. 30-day average fine aerosol mass concentrations from eight northeastern cities



Although the patterns exhibited by these monitoring data include occasional anomalies (as in the summer of 2000), summer peak concentrations in both cities of Figure 3-7 are generally much higher than the surrounding winter peaks. Figure 3-8 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.

3.2.4. Seasonal Mechanisms

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 the MANE-VU region record high (i.e., >15 $\mu g/m^3$) 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 allow pollution levels to build in an air mass as it is slowly transported 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 $\mu g/m^3$ 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[13] mornings (primarily 7 to 11 a.m.), fine particle concentrations at ground-level can actually increase (see Hartford, CT or Camden, NJ in Figure 3-9).

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-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 3-10). 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.

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

Figure 3-9. Mean hourly fine aerosol concentrations during the summer season

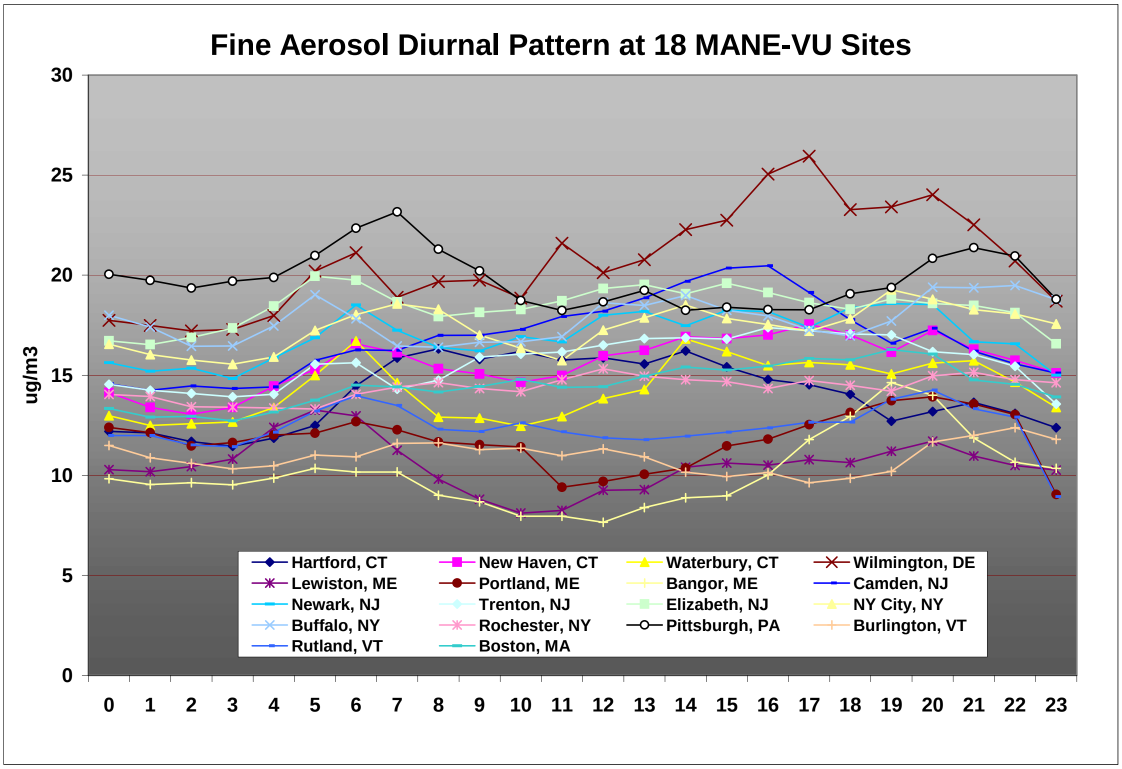
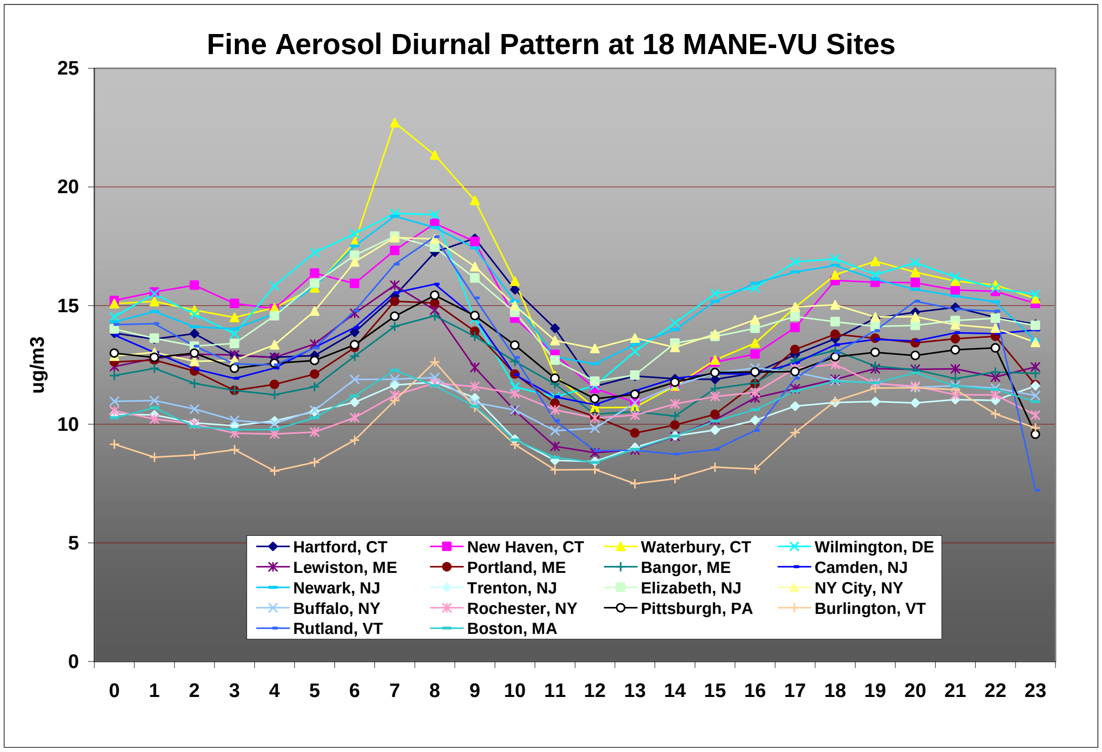


Figure 3-10. Mean hourly fine aerosol concentrations during the winter season



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 rural versus urban difference in PM concentrations.

3.3. RAIN data

Routine monitoring networks operated by USEPA, the National Park Service or state monitoring agencies collected much of the monitoring data shown so far. We anticipate that these data will continue to provide crucial information on the nature and extent of visibility impairment across the region. In addition, MANE-VU is also developing a network of enhanced monitoring sites capable of providing continuous data on the concentration, composition, and visibility impacts of fine particles. These data will be critical for understanding the more complex issues associated with organic carbon as well as any tradeoffs between sulfate and nitrate control. This Rural Aerosol Intensive Network (RAIN), which was first deployed in 2004, is therefore likely to play a prominent role in future visibility control programs and in the development of regional haze SIPs due in 2018.

NESCAUM coordinates the RAIN effort as a cooperative effort of the MANE-VU member state air agencies. The network covers the region from western Maryland (near large sulfur sources in the Ohio River Valley) through northwestern Connecticut to Acadia National Park in Maine. The initial network consists of these three rural, moderate elevation (700 to 2,500 feet) sites in a southwest to northeast line, all with detailed PM and visibility related measurements. The network design includes highly time resolved (1-2 hour) aerosol mass, composition, and optical property measurements. These provide enhanced insight into regional aerosol generation and source characterization, which are factors that drive short term visibility, and aerosol model performance and evaluation. In addition to these three sites, as of 2006 the NY-DEC/SUNY-Albany intensive measurement site at Pinnacle State Park (Addison, NY, seven miles southwest of Corning, NY, and seven miles north of the Pennsylvania border) has most of the RAIN parameters and methods other than visibility; efforts are underway to bring that site into the RAIN program (to ensure consistent method operation) and to add visibility measurements.

The RAIN sites use the Sunset Laboratory Model 3 field carbon analyzer and the new Thermo Environmental Model 5020 sulfate analyzer. This is the first use of these methods in routine, ongoing state-run networks. Combined with other more routine measurements such as IMPROVE aerosol, NGN-2 (wet) nephelometers, continuous $PM_{2.5}$, trace SO_2, ozone, meteorology, and automated digital visibility cameras (CAMNET), these methods make up the core RAIN monitoring lineup. Some of the RAIN sites will have additional related measurements, including “true” trace CO, NO_X, dry scattering (NGN-3a nephelometer), and other measurements. An Air and Waste

Management Association conference proceedings paper provides more information on the design of the network and examples of data from the summer of 2004.[14]

A longer term goal of RAIN is to enhance the network with other measurements and sites in future years. A National Weather Service ASOS visibility sensor at a RAIN site would allow the large network of existing ASOS data to be "tethered" to visibility measurements we understand well. Strong aerosol acidity, nitric acid, and ammonia are measurements that would be desirable on either an integrated or real-time basis. There are no continuous nitrate measurements in RAIN at this time because available methods suitable for routine deployment in state networks are not yet sufficiently robust.[15] Lack of continuous nitrate data is not a significant issue for this analysis since nitrate is not (yet) a major visibility factor at these rural sites. We expect that most of the continuous method data from RAIN to be available in real-time to web data resources like VIEWS, FASTNET and AIRNowTech by the end of 2006.

Measurements similar to those in RAIN done towards the west and south borders of the MANE-VU domain (Ohio and Virginia for example) would greatly enhance our understanding of the impact of the large sulfur source region in and around the Ohio River Valley on regional visibility. We encourage agencies and RPOs in those areas to develop intensive sites to complement the RAIN data.

As an initial test of the RAIN network, we examined visibility and related particle information for the third quarter of 2004 to determine how well the data from one (or both) of two recently installed semi-continuous monitors could reproduce the visibility data reported by existing NGN-2a nephelometers. The relevant data came from two monitors of interest: the Thermo Model 5020 (for sulfate) and the Sunset Labs (Model 3) semi-continuous analyzer for elemental and organic carbon. In addition, a Rotronic sensor (Model MP-101A, with active aspiration) measured relative humidity (RH) data on-site in order to supply a correction factor - f(RH) - for estimating the light scattering associated with various fine particle constituents.

Because ammonium sulfate is the major component of haze-producing particulate pollution in the northeastern United States, we examined sulfate data first. The Thermo Model 5020 reports sulfate and the IMPROVE algorithm for calculating visibility parameters assumes that all sulfate is in the form of ammonium sulfate. During high sulfate events in the rural Northeast this is not always the case, although it is still a reasonable first assumption.

The Thermo sulfate method has been shown to consistently under-report sulfate relative to IMPROVE sulfate measurements at the RAIN sites, but not at some other sites. Since the correlation with IMPROVE sulfate is high at all RAIN sites, the hourly RAIN sulfate data can be corrected to be "IMPROVE"-like with reasonable confidence. A RAIN technical memorandum describes this issue in more detail.[16] For the Acadia sulfate data used here, the daily correlation coefficient (R^2) between IMPROVE and

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[14] http://www.nescaum.org/documents/allen-awma_haze-rain-paper-oct-2004_proceedings.pdf/

[15] See the EPA method evaluation report at http://www.epa.gov/ttn/amtic/semicontin.html for more information.

[16] "Rural Aerosol Intensive Network (RAIN) Preliminary Data Analysis," available at: http://www.nescaum.org/documents/2006-05-memo8-rain.pdf/

Thermo sulfate is 0.95 (based on third and fourth quarter 2004 data). A correction factor of 1.30 is applied to the Thermo sulfate data based on the linear regression of IMPROVE and Thermo sulfate 24-hour samples for the third and fourth quarters of 2004 data; this correction makes the Thermo sulfate data consistent with the IMPROVE sulfate data.

We need three types of data to relate direct measures of atmospheric light scattering to a re-constructed or calculated estimate of light scattering based on observed sulfate levels: (1) direct measurements of light scattering (via nephelometer); (2) sulfate measurements; and (3) relative humidity measurements. The three RAIN sites in the northeastern United States measure each of these variables. Of these sites, however, only the McFarland Hill site at Acadia National Park in Maine is within a Class I area. Therefore, we selected data from the McFarland Hill site for the preliminary analysis we describe below.

Given the highly non-linear relationship between relative humidity and ammonium sulfate particle size and the limitations of relative humidity (RH) sensor accuracy at very high values of RH, we excluded from this analysis data collected when relative humidity was equal to or greater than 95 percent. Of the 2,208 hourly observations recorded from June 1 through September 30, this relative humidity ‘exclusion’ removed 525 hours. Data for an additional 92 hours were not available due to missing measurements from either the sulfate monitor or the nephelometer. We excluded a further 35 hours due to flagged nephelometer performance (such flags could be triggered by excess noise or rate-of-change in the signal). This left 1,556 hourly observation pairs for the third quarter, equivalent to a data capture rate of 70 percent - still a substantial sample given the nature of the emerging technology employed at the RAIN sites.

We multiplied sulfate concentrations from the Thermo 5020 by 1.37 to convert them to a mass equivalent for ammonium sulfate (this is the same factor IMPROVE uses). This new variable (SULFATE) is the strongest driver of light extinction in the Northeast because of the extreme size-dependent nature of ammonium sulfate light scattering, which in turn is highly (and very non-linearly) dependent on atmospheric relative humidity. Next, we converted the hourly RH values to a relative humidity function “f(RH)” by using a conversion table adopted by IMPROVE.[17] Then we applied a “dry specific scattering” coefficient of “3”[18] to the hourly SULFATE values. The final equation is shown below:

Reconstructed Sulfate Scattering = 3 * f(RH) * (SULFATE)

When we compared this reconstructed estimate of hourly light scattering to the IMPROVE NGN-2a nephelometer data (via a least-squares linear regression), we obtained an R^2 of 0.888. When two apparent outlier hours are removed (both of which occurred during periods when relative humidity was over 87 percent and changing rapidly) the regression slope is 0.846, the intercept is -5, and R^2 increases to 0.942. This

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[17] See: http://vista.cira.colostate.edu/improve/Tools/humidity_correction.htm; this is the original f(RH) table, not the new one.

[18] Described at http://vista.cira.colostate.edu/improve/Tools/ReconBext/reconBext.htm

implies that sulfate alone is responsible for approximately 85 percent of the light scattering (and visibility degradation) for this period of measurement.

Because elemental carbon absorbs light much more strongly than it scatters light, we added only the "light-scattering carbon" (OC) detected by the Sunset Model 3 to this reconstruction. The IMPROVE program uses the following equation to describe the impact of light-scattering carbon:

$$\textit{Reconstructed Carbon Scattering} = 4 * f_{org}(RH) * [OMC]$$

where the dry scattering coefficient of this carbon fraction is set at "4," the relative humidity factor is set at unity (due to the weak hygroscopicity of organic carbon), and OMC represents "organic mass by carbon." The IMPROVE Steering Committee has recently adopted 1.8 as an alternative organic mass multiplier (rather than 1.4) for calculating OMC values for use in reconstructed extinction as described in section 3.1. We have also used 1.8 for the analysis presented below.

Because the RAIN sites collect carbon data over two-hour periods, we averaged the McFarland Hill sulfate (Thermo-5020), scattering (NGN-2) and RH (Rotronic) hourly data into two-hour, whole number blocks in order to bring the data from Sunset Labs into the reconstruction equation. In addition, we subtracted a "filter blank" value for the Sunset OC data of 0.5 $\mu g/m^3$ (empirically derived from user experience of the Model 3) from the OC data prior to their use in the reconstruction calculation (OMC = (Sunset OC – 0.5) x 1.8). See Figure 3-11 for results of these reconstructed estimates of visibility using both sulfate and carbon measurements.

As indicated by Figure 3-11, adding the organic carbon data to the sulfate data significantly improves the agreement between reconstructed estimates of aerosol scattering and direct visibility measurements at the McFarland Hill site. Specifically, it appears that these two components of the ambient aerosol generally explain about 94 percent of the observed scattering at Acadia during the summer, with a very high correlation coefficient even at 2-hour intervals. This is excellent agreement considering that scattering from nitrate and crustal aerosol components is not included in this reconstruction.

These data demonstrate that the highly time-resolved nature of RAIN data is invaluable in examining short-term variations (i.e., on the order of days to weeks) in haze production and transport. The sulfate, carbon and other monitoring capabilities emerging from the RAIN project will provide another valuable tool to state and tribal authorities in seeking to understand the sources of regional haze and to craft effective control strategies. A more detailed analysis of RAIN data is available in a recently released MANE-VU technical memorandum.[19]

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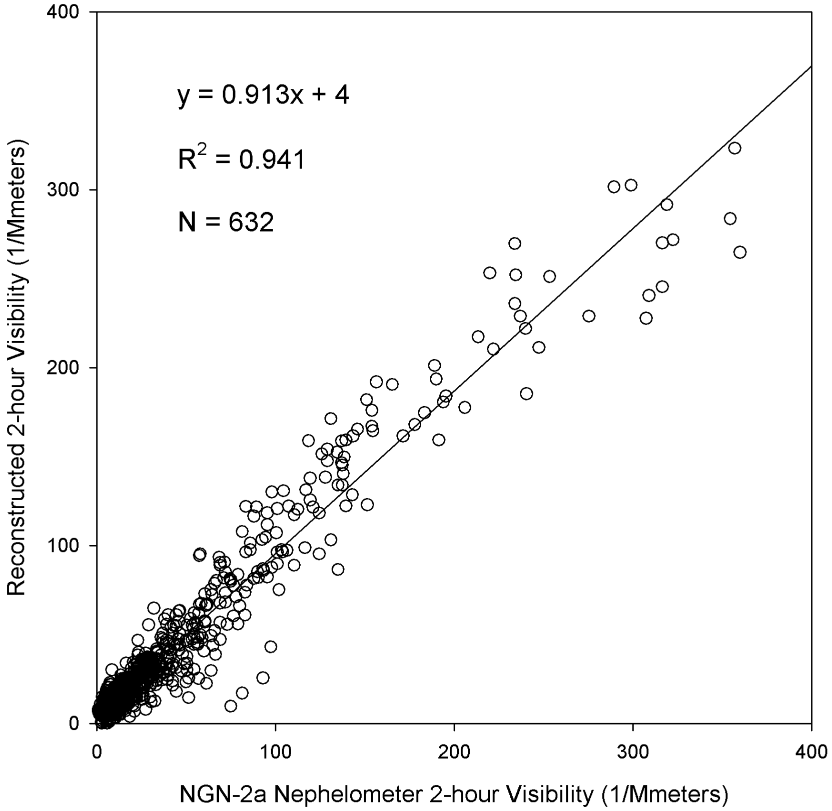
[19] "Rural Aerosol Intensive Network (RAIN) Preliminary Data Analysis," available at: http://www.nescaum.org/documents/2006-05-memo8-rain.pdf/

Figure 3-11. 2-Hour Reconstructed scattering at Acadia, Maine using semi-continuous SO_4 and OC data for the third quarter of 2004



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NESCAUM, “2002: A Year in Review,” Northeast States for Coordinated Air Use Management, Boston, MA, December, 2004b.

USEPA, “Guidance for Tracking Progress under the Regional Haze Rule,” EPA-454/B-03-004 September 2003a.

USEPA, “Guidance for Estimating Natural Visibility Conditions under the Regional Haze Program,” EPA-454/B-03-005 September 2003b.

4. HAZE-ASSOCIATED POLLUTANT EMISSIONS

This chapter explores the origin and quantity of haze-forming pollutants emitted in the eastern and the mid-Atlantic United States. It also describes the procedures used to prepare emissions inventory data for use in chemical transport models (Chapter 6 describes in greater detail the models themselves).

The pollutants that affect fine particle formation, and thus contribute to regional haze, are sulfur oxides (SO_X), nitrogen oxides (NO_X), volatile organic compounds (VOC), 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 below is the 2002 MANE-VU Version 2 regional haze emissions inventory. The emission inventories include carbon monoxide (CO), but we do not consider that pollutant here as it does not contribute to regional haze. The MANE-VU regional haze emissions inventory version 3.0, released in April 2006, has superseded version 2 for modeling purposes. This inventory update was developed through the Mid-Atlantic Regional Air Management Association (MARAMA) for the MANE-VU RPO. The comparative observations among recent emission inventories presented here (the 1996 USEPA NET and 1999 NEI) would hold true were version 3.0 substituted for version 2.0. [20]

The first section of this chapter describes emission characteristics by pollutant and source type (e.g., point, area, and mobile). The second section describes on-going efforts to process emissions inventory data in support of air quality modeling. The final section provides source apportionment estimates for several MANE-VU Class 1 areas based on 2002 SO_2 inventory data.

4.1. Emissions Inventory Characteristics

4.1.1. Sulfur Dioxide (SO_2)

SO_2 is the primary precursor pollutant for sulfate particles. Sulfate particles commonly account for more than 50 percent of particle-related light extinction at northeastern Class I areas on the clearest days and for as much as or more than 80 percent

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[20] EPA's Emission Factor and Inventory Group (EFIG) (USEPA/OAR (Office of Air and Radiation)/OAQPS (Office of Air Quality Planning and Standards)/EMAD (Emissions, Monitoring and Analysis Division) prepares a national database of air emissions information with input from numerous state and local air agencies, from tribes, and from industry. This database contains information on stationary and mobile sources that emit criteria air pollutants and their precursors, as well as hazardous air pollutants (HAPs). The database includes estimates of annual emissions, by source, of air pollutants in each area of the country on an annual basis. The NEI includes emission estimates for all 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands. Emission estimates for individual point or major sources (facilities), as well as county level estimates for area, mobile and other sources, are available currently for years 1985 through 1999 for criteria pollutants, and for years 1996 and 1999 for HAPs. Data from the NEI help support air dispersion modeling, regional strategy development, setting regulation, air toxics risk assessment, and tracking trends in emissions over time. For emission inventories prior to 1999, the National Emission Trends (NET) database maintained criteria pollutant emission estimates and the National Toxics Inventory (NTI) database maintained HAP emission estimates. Beginning with 1999, the NEI began preparing criteria and HAP emissions data in a more integrated fashion to take the place of the NET and the NTI.

on the haziest days. Hence, SO_2 emissions are an obvious target of opportunity for reducing regional haze in the eastern United States. Combustion of coal and, to a 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, 2001a).

Figure 4-1 shows SO_2 emissions trends in the MANE-VU states extracted from the NEI for the years 1996, 1999, and the 2002 MANE-VU inventory (USEPA, 2005; MARAMA, 2004). 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 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 4-2 shows the percent contribution from different source categories to overall, annual 2002 SO_2 emissions in the 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) are another important source category in the 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, 2001a).

4.1.2. Volatile Organic Compounds (VOC)

Existing emission inventories generally refer to “volatile organic compounds” (VOCs) for hydrocarbons whose volatility in the atmosphere makes them particularly important from the standpoint of ozone formation. From a regional haze perspective, we are concerned less with the volatile organic gases emitted directly to the atmosphere and more with the secondary organic aerosol (SOA) that the VOCs form after condensation and oxidation processes. Thus the VOC inventory category is of interest primarily from the organic carbon perspective of $PM_{2.5}$. After sulfate, organic carbon generally accounts for the next largest share of fine particle mass and particle-related light extinction at northeastern Class I sites. The term organic carbon encompasses a large number and variety of chemical compounds that may come directly from emission sources as a part of primary PM or may form in the atmosphere as secondary pollutants. The organic carbon present at Class I sites almost certainly includes a mix of species, including pollutants originating from anthropogenic (i.e., manmade) sources as well as biogenic hydrocarbons emitted by vegetation. Recent efforts to reduce manmade organic carbon emissions have been undertaken primarily to address summertime ozone formation in urban centers. Future efforts to further reduce organic carbon emissions may be driven by programs that address fine particles and visibility.

Figure 4-1. State Level Sulfur Dioxide Emissions

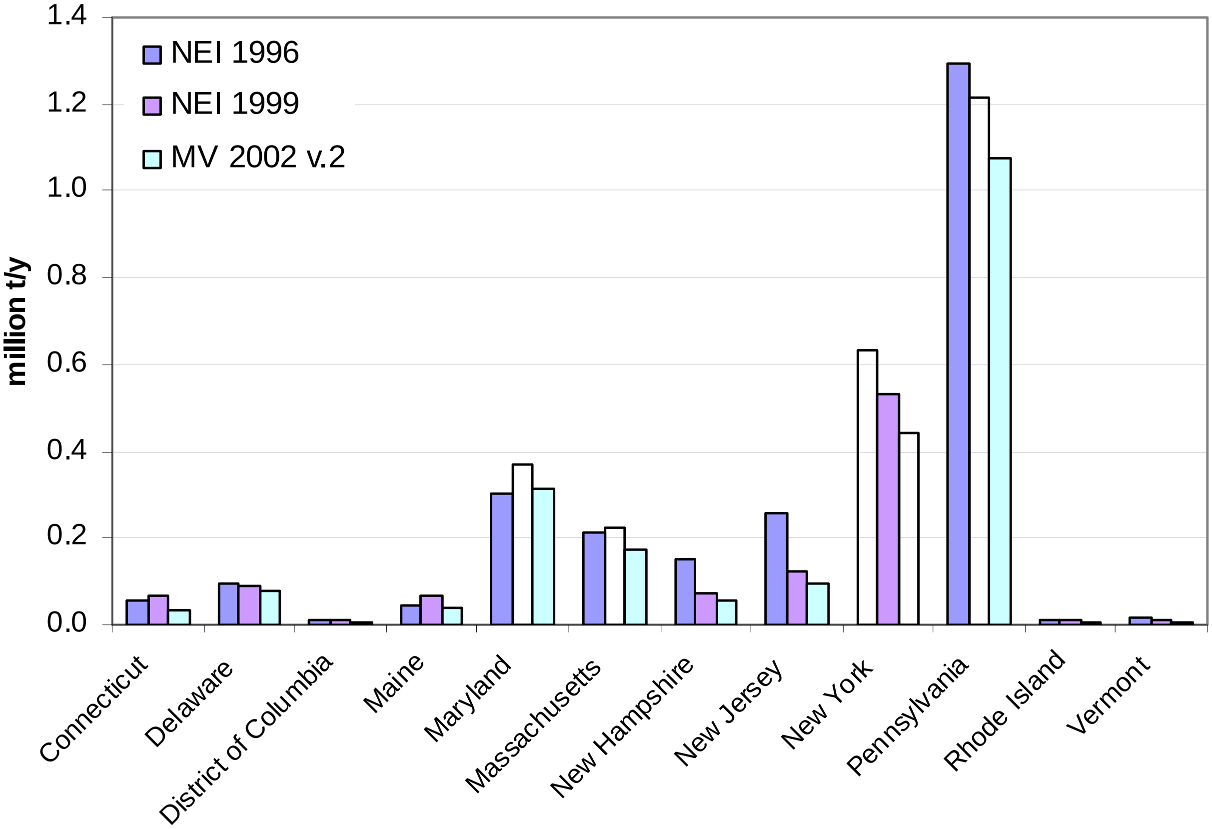
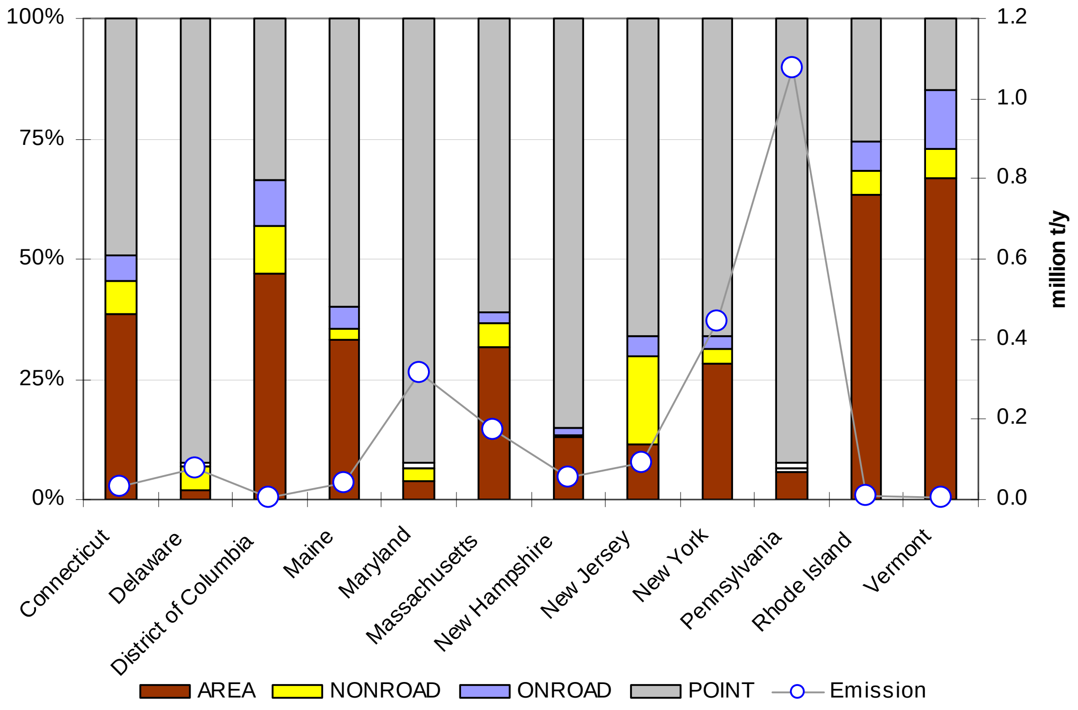


Figure 4-2. SO$_2$ (Bar graph: Percentage fraction of four source categories, Circle: Annual emissions amount in 10^6 tons per year)

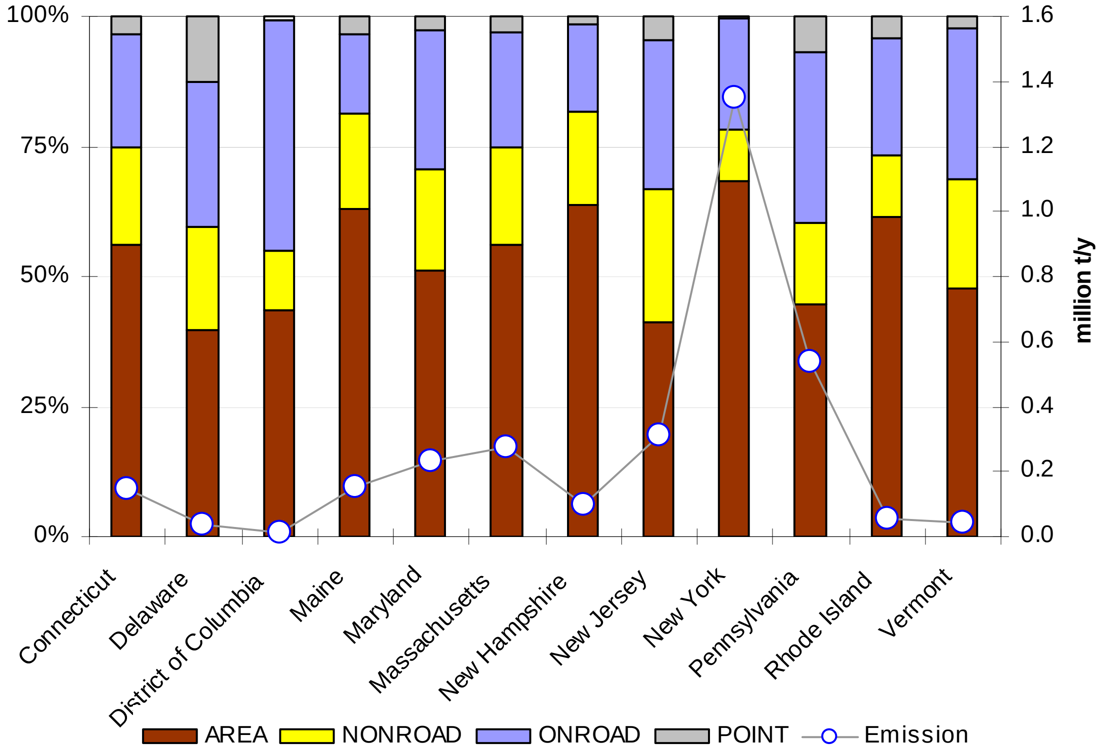


Understanding the transport dynamics and source regions for organic carbon in northeastern Class I areas is likely to be more complex than for sulfate. This is partly because of the large number and variety of OC species, the fact that their transport characteristics vary widely, and the fact that a given species may undergo numerous complex chemical reactions in the atmosphere. Thus, the organic carbon contribution to visibility impairment at most Class I sites 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.

As shown in Figure 4-3, the VOC inventory is dominated by mobile and area sources. 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).

Biogenic VOCs may play an important role within the rural settings typical of Class I sites. The oxidation of hydrocarbon molecules containing seven or more carbon atoms is generally the most significant pathway for the formation of light-scattering organic aerosol particles (Odum et al., 1997). Smaller reactive hydrocarbons that may contribute significantly to urban smog (ozone) are less likely to play a role in organic aerosol formation, though we note that high ozone levels can have an indirect effect on visibility by promoting the oxidation of other available hydrocarbons, including biogenic

Figure 4-3. VOC (Bar graph: Percentage fraction of four source categories, Circle: Annual emissions amount in 10^6 tons per year)



emissions (NESCAUM, January 2001). In short, we need further work to characterize the organic carbon contribution to regional haze in the Northeast and Mid-Atlantic states and to develop emissions inventories that will be of greater value for visibility planning purposes.

4.1.3. Oxides of Nitrogen (NO_X)

NO_X emissions contribute directly to visibility impairment in the eastern U.S. by forming light-scattering nitrate particles. Nitrate generally accounts for a substantially smaller fraction of fine particle mass and related light extinction than sulfate and organic carbon at northeastern Class I sites. 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 2001a).

Figure 4-4 shows NO_X emissions in the MANE-VU region 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 the MANE-VU region 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.

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 4-5. 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. While there are fewer uncertainties associated with available NO_X estimates than in the case of other key haze-related pollutants — including primary fine particle and ammonia emissions — further efforts could improve current inventories in a number of areas (NESCAUM, 2001a).

In particular, better information on the contribution of area and non-highway mobile sources may be of most interest in the context of regional haze planning. First, available emission estimation methodologies are weaker for these types of sources than for the large stationary combustion sources. Moreover, because SO_2 and NO_X emissions must mix with ammonia to participate in secondary particle formation, emissions that occur over large areas at the surface may be more efficient in secondary fine particulate formation than concentrated emissions from isolated tall stacks (Duyzer, 1994).

Figure 4-4. State Level Nitrogen Oxides Emissions

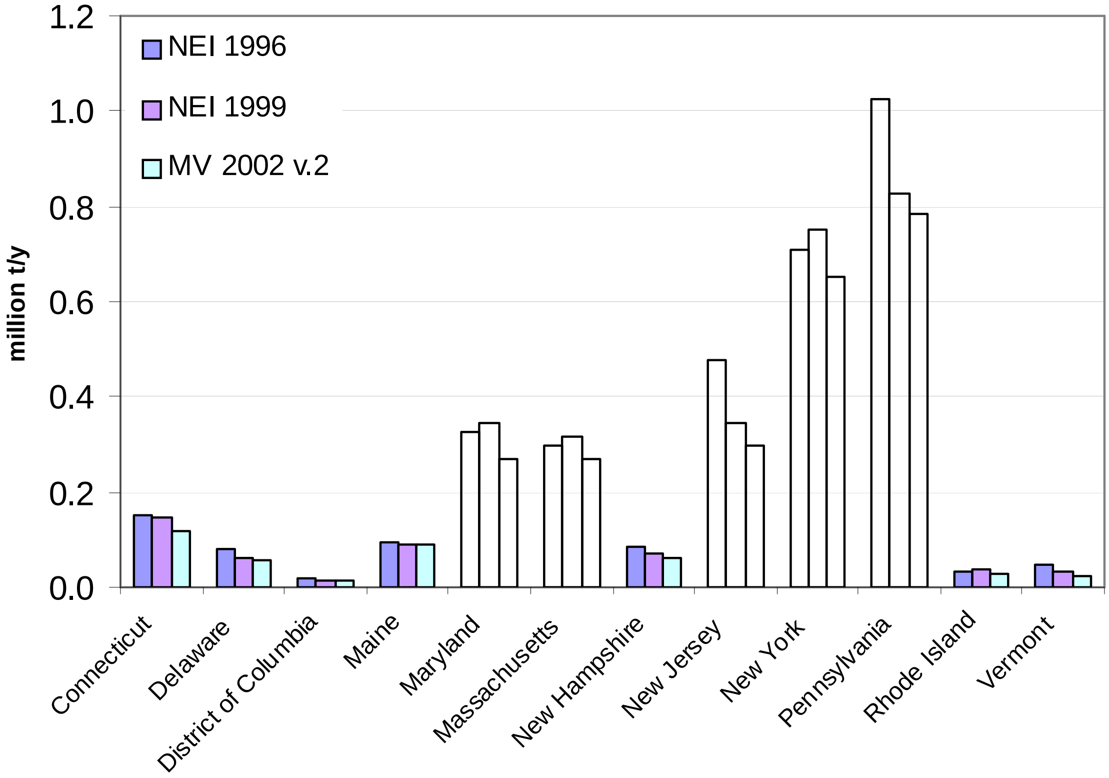
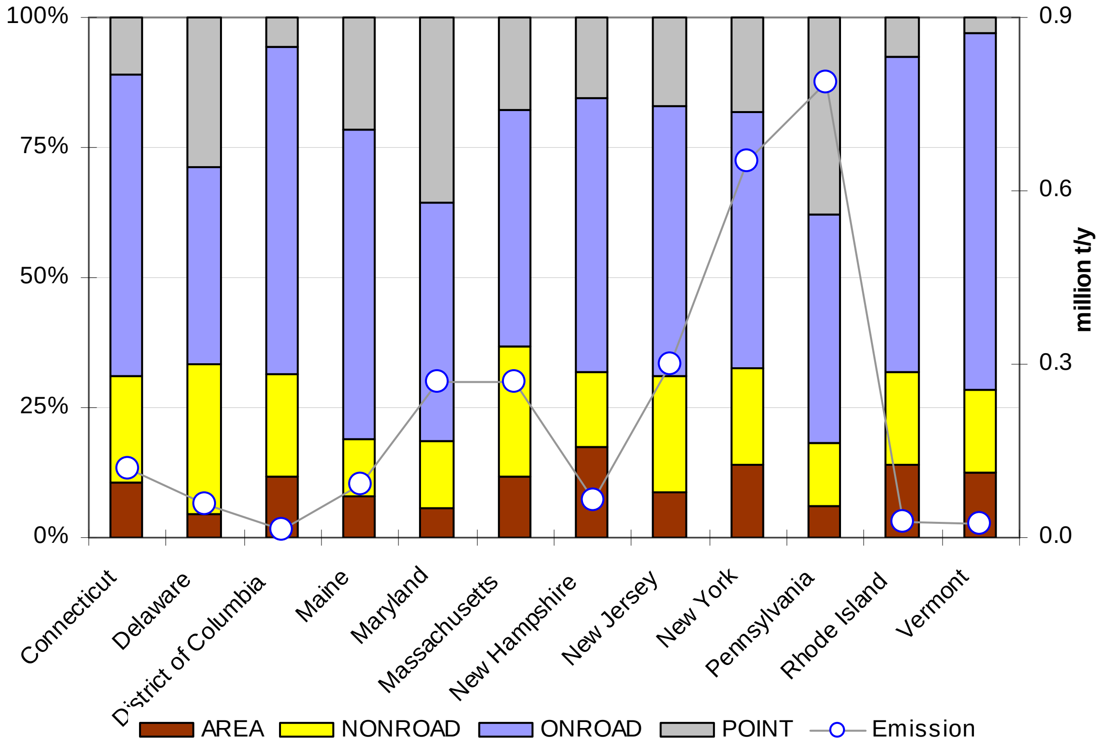


Figure 4-5. NO_X (Bar graph: Percentage fraction of four source categories, Circle: Annual emissions amount in 10^6 tons per year)



4.1.4. 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) can also contribute to regional haze. 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 4-6 and Figure 4-7 show PM_{10} and $PM_{2.5}$ emissions for the MANE-VU states for the years 1996, 1999, and 2002. Note that for PM_{10} the inventory values 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 six to eleven 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 two to three percent. Moreover, the crustal fraction includes material of natural origin (such as soil or sea salt) that is not targeted under the 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 to the extent that 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 non-attainment status with respect to the NAAQS for PM_{10}.

Figure 4-6. State Level Primary PM_{10} Emissions

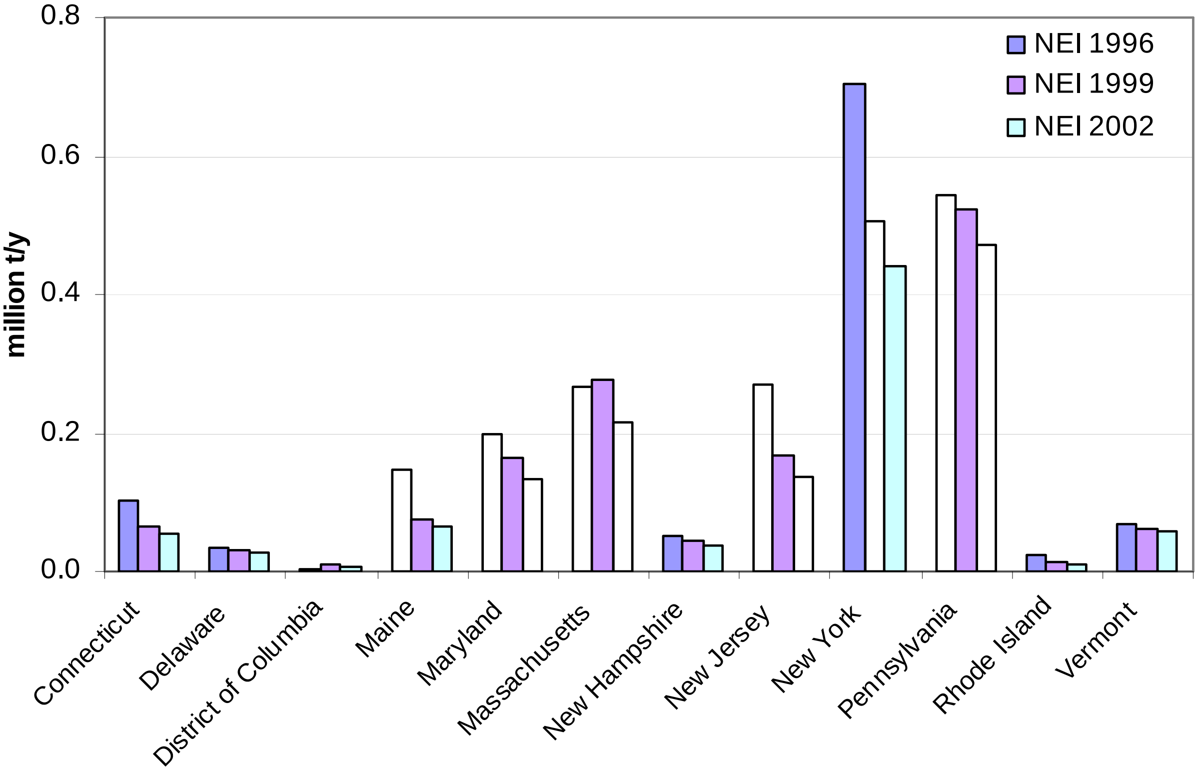
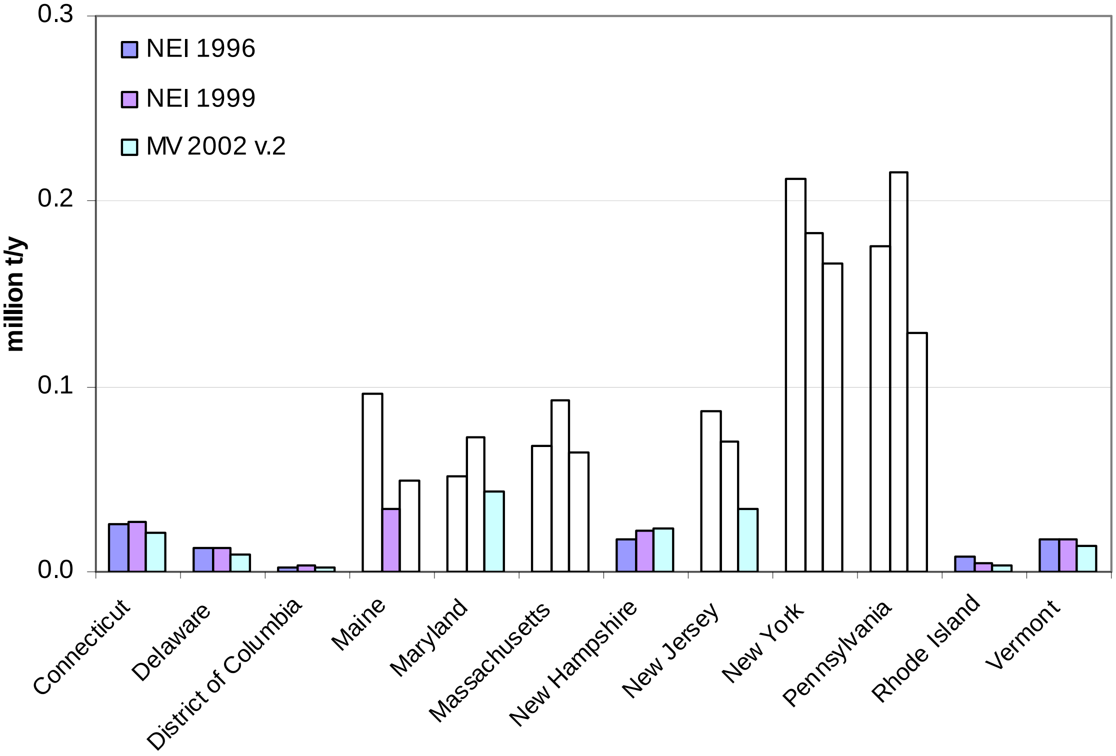


Figure 4-7. State Level Primary $PM_{2.5}$ Emissions



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 4-8 and Figure 4-9 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.

4.1.5. 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 agriculture and fertilizer use accounted for approximately 86 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.[21]

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[21] 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.

Figure 4-8. Primary PM$_{10}$ (Bar graph: Percentage fraction of four source categories, Circle: Annual emissions amount in 10^6 tons per year)

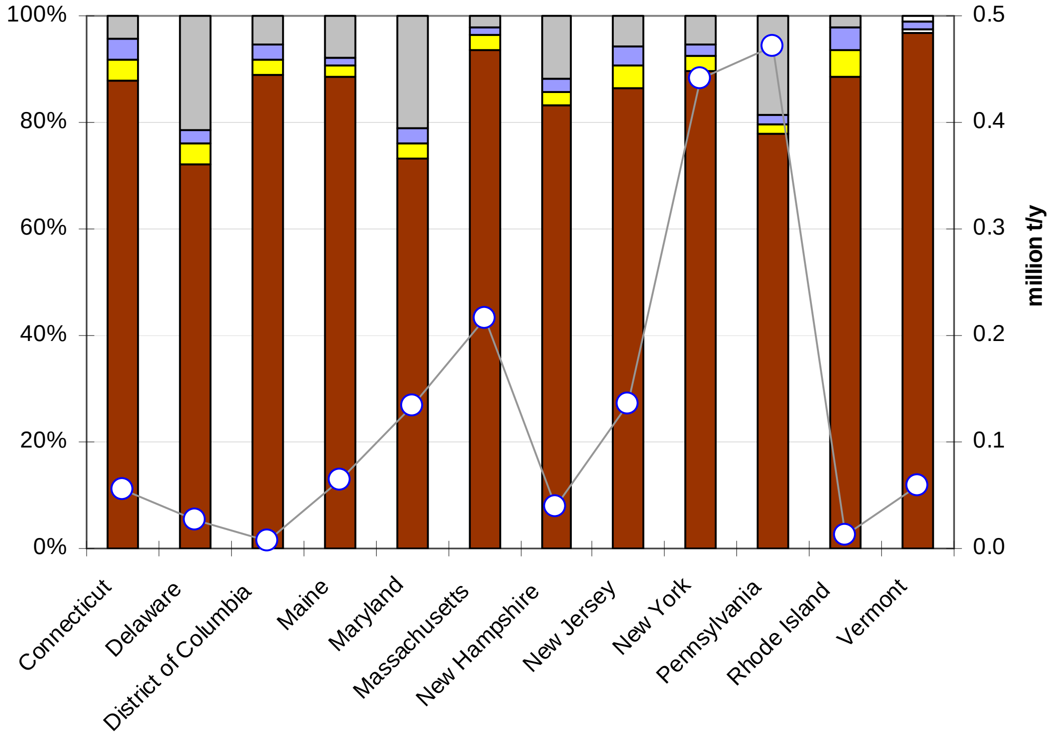
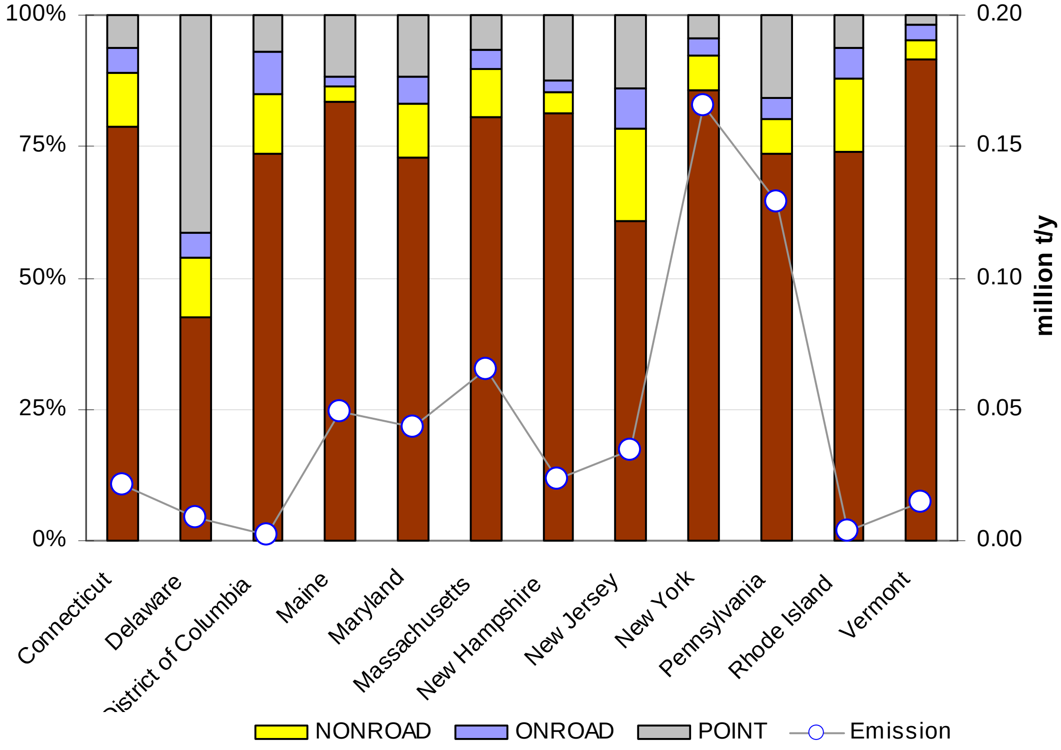


Figure 4-9. Primary PM$_{2.5}$ (Bar graph: Percentage fraction of four source categories, Circle: Annual emissions amount in 106 tons per year)

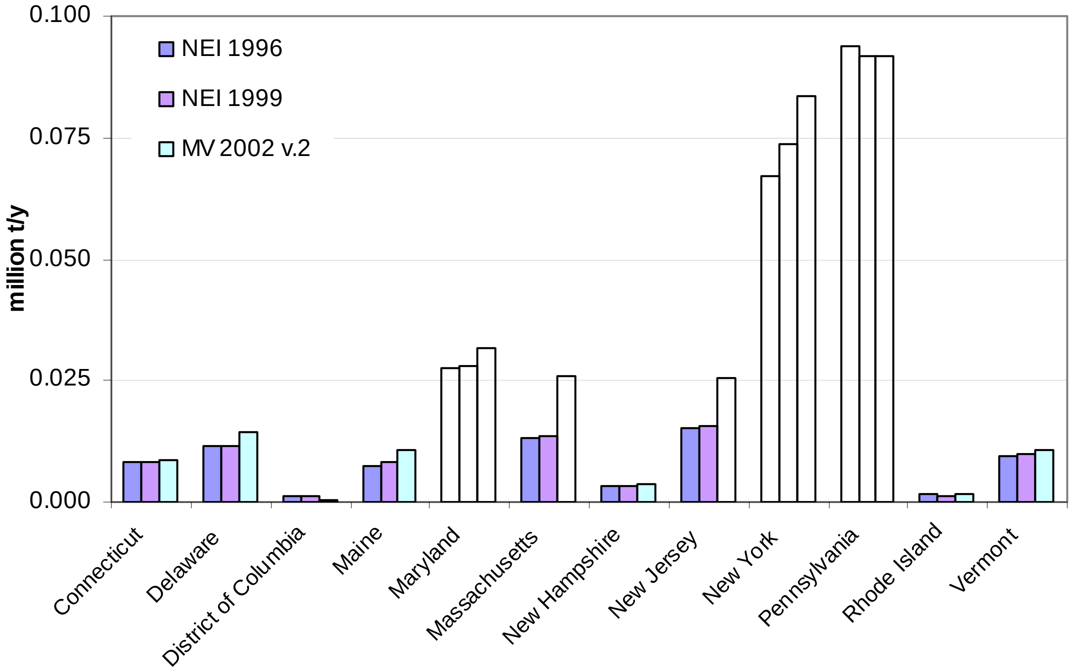


To address the need for improved ammonia inventories, MARAMA, NESCAUM and USEPA funded researchers at Carnegie Mellon University (CMU) in Pittsburgh to develop a regional ammonia inventory (Davidson et al., 1999). This study focused on three issues with respect to current emissions estimates: (1) a wide 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.

The CMU project established an inventory framework with source categories, emissions factors, and activity data that are readily accessible to the user. With this framework, users can obtain data in a variety of formats[22] and can make updates easily, allowing additional ammonia sources to be added or emissions factors to be replaced as better information becomes available (Strader et al., 2000; NESCAUM, 2001b).

Figure 4-10 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 4-11. Specifically, emissions from agricultural sources and livestock production account for the largest share of estimated ammonia emissions in the MANE-VU region, except in the District of Columbia. The two remaining sources with a significant emissions contribution are wastewater treatment systems and gasoline exhaust from highway vehicles.

Figure 4-10. State Level Ammonia Emissions



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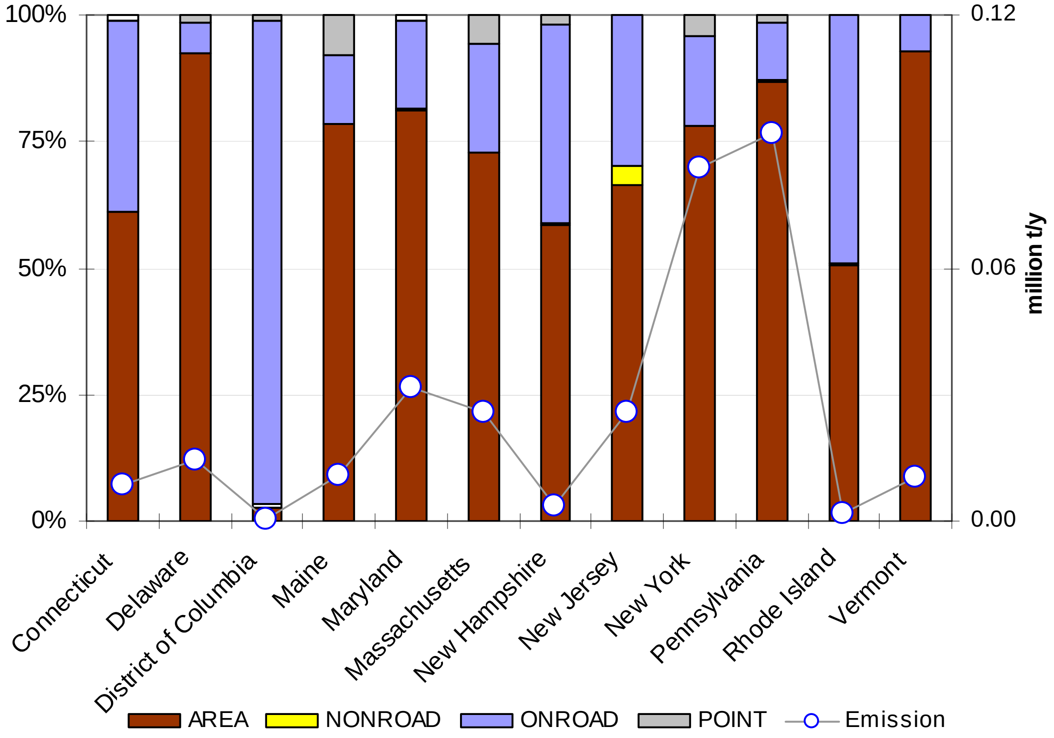
[22] For example, the user will have the flexibility to choose the temporal resolution of the output emissions data or to spatially attribute emissions based on land-use data.

Figure 4-11. NH_3 (Bar graph: Percentage fraction of four source categories, Circle: Annual emissions amount in 10^6 tons per year)



4.2. Contribution Assessments Based on Emissions Inventories

Two data analysis methods have been developed that directly combine emission inventory data with meteorological data in order to provide first-order contributions to observed sulfate from individual states. The first approach, known as "Q/d," evaluates the state contribution as a proportion of the ratio of the total SO_2 emissions from that state and the distance from the state to the receptor. States and sources are assigned wind sectors to account for prevailing wind patterns in establishing contributions. The second approach, known as "Emissions times Upwind Probability," evaluates the state contribution through the use of ensemble back trajectories (See Appendix A for a more detailed description of trajectory methods). The back trajectory-derived residence times of air parcels have been mapped onto a grid to create a "residence time probability field," which is then multiplied by an SO_2 emissions field to obtain estimated source contributions. The results of the two approaches are compared for receptor sites in and around the MANE-VU region.

4.2.1. Sulfur Dioxide Emissions Divided by Distance

Aggregated over long periods of time and large geographic areas, the total atmospheric sulfate contribution from a specific source, state, or region should be approximately proportionate to its SO_2 emissions. For specific receptor locations, like a Class 1 visibility area, relative impacts decrease with increasing distance from the source. Impacts diminish over distance as pollutants are dispersed in the atmosphere and removed through deposition. For non-reactive primary pollutant emissions, the relationship between atmospheric concentrations and distance (d) can be approximated as a function of $1/d^2$. For secondary pollutants like sulfate, reductions in ambient concentrations that occur as a result of dispersion and deposition mechanisms are partially offset by the formation of secondary aerosol such that an increasing fraction of the remaining downwind sulfur is converted to aerosol sulfate. In these cases, the effects of distance are better characterized by the function 1/d. During regional sulfate episodes when sulfur conversion rates are enhanced by the presence of gas and aqueous-phase oxidants, pollutant concentrations decline even less rapidly with distance as accelerated aerosol formation rates work to both generate more sulfate and reduce the remaining sulfur available for deposition (deposition rates are roughly an order of magnitude slower for sulfate than for SO_2).

One simple technique for deducing the relative impact of emissions from specific point sources on a specific receptor site involves calculating the ratio of annual emissions (Q) to source-receptor distance (d).[23] This empirical relationship is reasonable based on simple dispersion assumptions. Results from SO_2 modeling using the CALPUFF (California Puff) model (EarthTech, 2004) further bolster its validity by showing a strong relationship between emissions and distance. In fact, this extremely simple method of estimating impact can be significantly improved to account for some aspects of meteorology by scaling results according to the extremely linear relationships between CALPUFF and Q/d values within specific wind sectors.

The geographic domain of the sources included in the Q/d study consisted of U.S. states in the CENRAP, MANE-VU, VISTAS, and MIDWEST RPO regions. Canadian provinces in the lower eastern region were also included. The categories of SO_2 emission sources included in this analysis were area sources (e.g., residential boilers and heaters), non-road mobile sources (e.g., tractors and construction vehicles), and point sources (e.g., industrial smokestacks and power generation facilities).[24] Results were calculated for seven receptors including: Acadia National Park, Brigantine Wilderness in the Forsythe Wildlife Preserve, Dolly Sods Wilderness, Lye Brook Wilderness, Moosehorn Wilderness, Presidential Range-Dry River Wilderness, and Shenandoah National Park.

The empirical formula that relates emission source strength and estimated impact can be expressed through the equation $I=C_i*Q/d$. In this equation, the strength of an emission source, Q, is linearly related to the impact, I, that it will have on a receptor located a distance, d, away. The effect of meteorological prevailing winds can be factored into this approach by establishing the constant, C_i, as a function of the sectors relative to the receptor site. This relationship can be established by comparing Q/d values to modeled impacts, which are also dependent on prevailing wind patterns at the site of impact. By establishing a different constant for each sector, based on prior modeling results – in this case, CALPUFF results – we are in effect "scaling" Q/d results

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[23] We calculated distances using the Haversine formula, which uses spherical geometry to calculate the distance between two points on the surface of a sphere. Because the Earth is not an exact sphere, use of this formula introduces a small amount of error — on the order of 0.5% — in the distance calculations for any two locations on the Earth's surface (see http://mathforum.org/library/drmath for further details).

[24] On-road mobile sources contribute about 2% of the SO_2 inventory nationally (See Figure 4-2 for regional breakdown) and were not considered significant enough to include in this analysis, which does not provide results to that level of precision.

by CALPUFF-calculated source impacts. The absolute impacts produced are then dependent on the CALPUFF results, however the relative contributions of each source within a wind sector is established completely independent of the CALPUFF calculation, yielding a quasi-independent method of apportionment to add to our weight-of-evidence approach.

To determine the appropriate constant for each wind sector relative to a given receptor, a linear regression analysis was performed on 778 sources in the eastern U.S. with emissions data available from the continuous emissions monitoring system (CEMS) for 2002. The Q/d values were calculated for these sources and compared with their modeled source impacts from the CALPUFF model (see Phase I modeling discussed in Appendix D). The sites were grouped by angle into “wind sectors” such that each wind sector had a best-fit line with as high a correlation coefficient (R^2) value as possible. Most sectors had an R^2 above or near 0.90. The slopes of the resulting best-fit lines were used as the constants in the above equation.[25]

To calculate the impact that each state had on a given receptor, the area and non-road SO_2 emission sources were summed across the entire state, and the distance to the receptor site for those emission sources was calculated based on that state’s geographic center, adjusted for population density.[26] In this way, the area and non-road emissions were treated as a single point source located at the population-weighted center of each state. These impacts were then added to the impact of the point sources that were calculated individually. The sum of area, non-road, and point source impacts for each state was used to compare the contributions relative to other states in the eastern U.S. and parts of Canada.

The principal contributors to the MANE-VU receptors, according to this method, include the midwestern states of Indiana and Ohio, as well as Pennsylvania and New York. This is due not only to the large emissions from these states, but also to the predominantly westerly winds that carry Midwest pollution eastward (the Midwest was located in the wind sector with the highest C_i-value, five times that of the lowest Ci-value). Table 4-1 shows the relative contribution of eastern states and Canadian provinces on several receptor sites in the region. Figure 4-12 and Figure 4-13 show the corresponding Q/d rankings across a set of northern and southern Class I areas in or near MANE-VU.

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[25] The analysis resulted in best-fit lines that did not always go through the origin. By forcing the regression lines through the origin, we ensure that a source with zero emissions would correspond to zero impact at the receptor. After having forced the best-fit lines through the origin, R^2 values remained greater than 0.77 and changed less than 0.01 from the original regression. The changes to the slope were considered insignificant, with an average change of 4%, ranging from -11% to 16%; the extremes occurred for plots with relatively few points and on the low end of R-squared correlations. Some angle ranges were not associated with a wind sector because of insufficient data for that angle range. For example, there was a lack of data for Lye Brook Wilderness receptor in the 0-144^o angle range. This angle sector and similar sectors lacking adequate data were assigned the lowest C_i-value amongst the other wind sectors of the same receptor site. The impact of this decision should be small given the relatively few sources in these directions and their tendency to be downwind of the receptor.

[26] Calculations using county-level emissions and distance to county centroid to receptor were compared to the approach used here. This added complexity, however, did not substantially change the predicted impacts nor the relative rankings among states.

Table 4-1. 2002 SO_2 CALPUFF-scaled Emissions over Distance Impact ($\mu g/m^3$)

STATE	ACADIA	LYE BROOK	BRIGANTINE	SHENANDOAH	EMISSIONS
Pennsylvania	0.19	0.30	0.38	0.43	1,090,562
Ohio	0.19	0.23	0.27	0.46	1,273,755
West Virginia	0.08	0.09	0.16	0.32	573,136
Maryland	0.05	0.06	0.24	0.21	292,970
New York	0.12	0.15	0.15	0.13	341,493
Indiana	0.11	0.11	0.14	0.18	914,039
North Carolina	0.07	0.06	0.14	0.26	510,452
Virginia	0.06	0.04	0.14	0.17	309,709
Georgia	0.07	0.07	0.11	0.14	605,040
Kentucky	0.06	0.06	0.11	0.14	521,583
Michigan	0.08	0.08	0.06	0.10	432,166
Illinois	0.07	0.07	0.07	0.10	642,264
Tennessee	0.04	0.04	0.07	0.09	423,705
New Jersey	0.02	0.02	0.14	0.07	64,437
Alabama	0.05	0.05	0.07	0.08	548,054
Texas	0.04	0.04	0.05	0.06	849,831
Florida	0.04	0.03	0.06	0.07	537,327
Massachusetts	0.08	0.02	0.03	0.05	123,754
South Carolina	0.04	0.02	0.05	0.07	262,867
Delaware	0.02	0.02	0.10	0.04	83,549
Missouri	0.04	0.04	0.05	0.05	361,911
Wisconsin	0.03	0.03	0.03	0.04	263,040
Maine	0.05	<0.01	<0.01	0.01	39,423
Kansas	0.01	0.01	0.01	0.01	136,104
New Hampshire	0.03	<0.01	0.01	0.01	53,772
Minnesota	0.01	0.01	0.01	0.01	124,151
Mississippi	0.01	0.01	0.01	0.02	126,456
Iowa	0.01	0.01	0.01	0.01	230,676
Connecticut	0.01	0.01	0.01	0.01	41,093
Oklahoma	0.01	0.01	0.01	0.01	139,327
Louisiana	0.01	0.01	0.01	0.02	346,170
Arkansas	<0.01	<0.01	0.01	0.01	140,096
Nebraska	0.01	<0.01	<0.01	0.01	46,074
Rhode Island	<0.01	<0.01	<0.01	<0.01	2,531
Vermont	<0.01	<0.01	<0.01	<0.01	1,575
Dist. of Columbia	<0.01	<0.01	<0.01	<0.01	1,715
Ontario	0.01	0.24	0.12	0.15	5,010
New Brunswick	0.15	0.01	0.02	0.02	1,261
Quebec	0.09	0.02	0.03	0.05	6,567
Nova Scotia	0.08	0.01	0.02	0.02	7,566
Newfoundland	0.01	<0.01	<0.01	0.01	15,287
Prince Edward Is.	<0.01	<0.01	<0.01	<0.01	10,157

Figure 4-12. Ranked state percent sulfate contributions to Northeast Class I receptors based on emissions divided by distance (Q/d) results

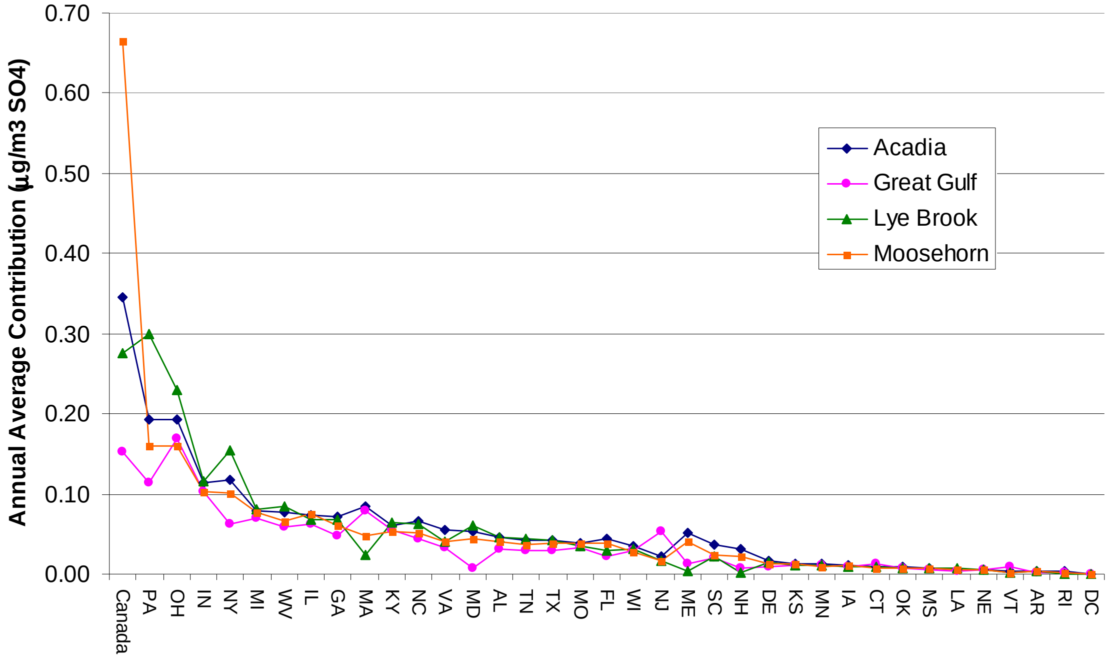
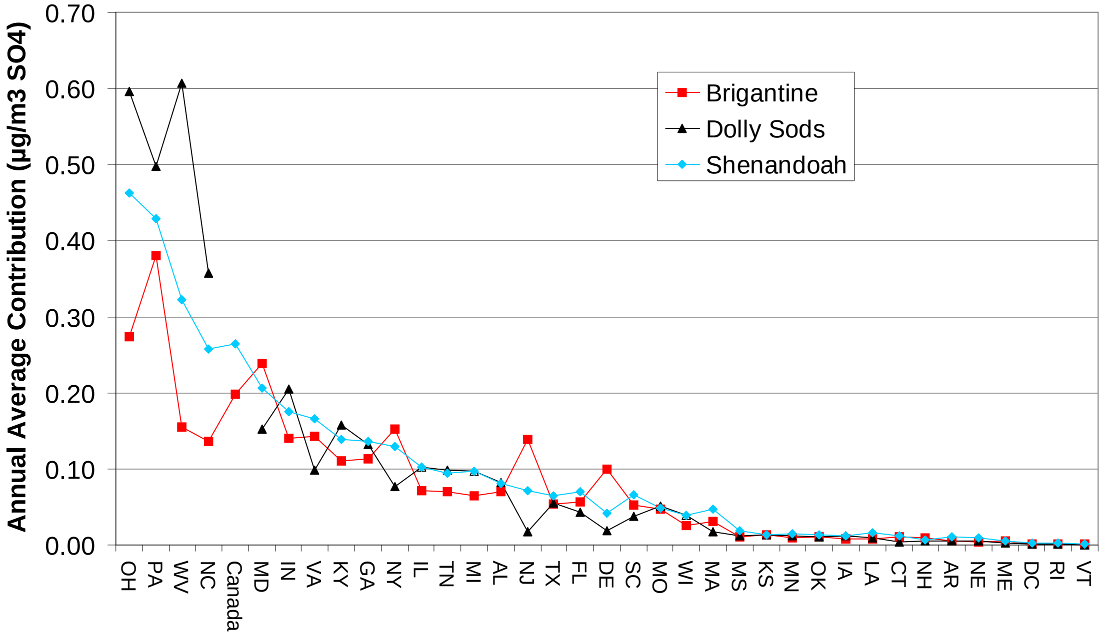


Figure 4-13. Ranked state percent sulfate contributions to Mid-Atlantic Class I receptors based on emissions divided by distance (Q/d) results



It is difficult to draw firm conclusions from what is essentially an empirical relationship between emission source strength, distance and observed impacts at receptor sites, but the addition of the CALPUFF-derived scale factors to this approach yields important insights as to the abilities of fairly simple screening techniques to accurately predict potential contributions to downwind receptors. This is borne out by the high degree of correspondence between the relative contributions of regions as identified by this and other techniques shown in Chapter 8.

4.2.2. Emissions times Upwind Probability

The Emissions times Upwind Probability method of assessing contribution to pollution involves multiplying the back-trajectory calculated residence time probability for a grid cell with the total emissions – over the same time period – from that grid cell. The product is an emissions-weighted probability field that can be integrated within state boundaries to calculate relative probabilities of each state contributing to pollution transport.

A back trajectory is the path that a parcel of air is calculated to have taken prior to its arrival at a given receptor (See Chapter 5). The back trajectories used in this study were calculated by the HYSPLIT system (Draxler, 1997 and 1998). Five years of back trajectories, calculated eight times per day results in 14,600 back trajectories. The back trajectories are 72-hours in length and have calculated endpoints, or locations, at hourly intervals that specify the air mass path. The endpoints from all trajectories are mapped into a matrix of residence times spent in individual grid cells over the five year period. The resulting sum expresses the likelihood that air spent time in a particular quarter degree longitude by quarter degree latitude grid cell over a domain between 25^o and 57^o latitude and -110^o to -50^o longitude. These residence times are then multiplied by the MANE-VU base year SO_2 emission inventory that has been allocated to a 12 km horizontal grid based on a Lambert Conformal projection.[27] The resulting product matrix contains the SO_2-weighted residence times that are then numerically integrated within the boundaries of each state to define a "contribution" for each state. This provides a relative ranking of contribution by state that can be used to compare with other methods of attribution.[28]

The area of analysis included states from Maine to Mississippi. Several states lie on the periphery of our available SO_2 emissions field and were used in the study despite an incomplete inventory of SO_2 emissions for the far edges of each state; these included

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[27] Since the latitude-longitude projection of the residence time grid is different than the Lambert conformal projection of the emissions grid, there is not a one-to-one mapping. We therefore interpolated each residence time grid cell to increase the spatial resolution to $1/20^o$ latitude by $1/20^o$ longitude. Each residence time cell was then associated with the nearest SO_2 emission cell to ensure that each SO_2 emission component of the inventory was associated with the approximate residence time that was spent in nearest proximity to the emissions region. A distance of one-quarter degree between associated grid cells was used as a cutoff for the analysis. In other words, the product of a particular SO_2 cell and residence time cell would not be used if the geographical distance between them was greater than one-quarter degree (latitude or longitude).

[28] Note that the absolute units are expressed as nmole/hr, which represent a fractional contribution of a grid cell's emission rate that is likely to influence a downwind receptor. The physical meaning of this contribution is not clear, so this has been used in a relative sense only.

Missouri, Arkansas, Mississippi, Alabama, and Georgia.[29] Canada has significant SO_2 emissions in the domain of the SO_2 grid, hence contributions have been calculated for portions of Ontario, Quebec and New Brunswick that were within the SO_2 emission grid. Table 4-2 provides a ranking of state contributions and Figure 4-14 and Figure 4-15 show the ranked contribution for two groupings of Class I sites in or near MANE-VU.

Table 4-2. 2002 SO_2 Upwind Probability (percent contribution)

	ACADIA	LYEBROOK	BRIGANTINE	SHENANDOAH
West Virginia	0.06	0.07	0.09	0.19
Ohio	0.09	0.11	0.10	0.12
Pennsylvania	0.09	0.13	0.13	0.07
Kentucky	0.04	0.05	0.06	0.09
Indiana	0.05	0.05	0.05	0.06
New York	0.07	0.11	0.04	0.02
Virginia	0.03	0.02	0.06	0.06
North Carolina	0.02	0.01	0.05	0.07
Illinois	0.06	0.05	0.04	0.04
Georgia	0.02	0.02	0.04	0.05
Michigan	0.04	0.04	0.02	0.02
Tennessee	0.02	0.01	0.02	0.04
Maryland	0.02	0.02	0.04	0.03
New Jersey	0.02	0.02	0.07	0.01
Alabama	0.01	0.01	0.02	0.02
South Carolina	0.01	0.01	0.02	0.02
Wisconsin	0.02	0.02	0.01	0.01
Missouri	0.01	0.01	0.01	0.01
Delaware	<0.01	0.01	0.02	<0.01
Massachusetts	0.02	0.01	<0.01	<0.01
New Hampshire	0.02	0.01	<0.01	<0.01
Minnesota	0.01	0.01	<0.01	<0.01
Connecticut	0.01	0.01	<0.01	<0.01
Maine	0.02	<0.01	<0.01	<0.01
Iowa	0.01	<0.01	<0.01	<0.01
Dist. of Columbia	<0.01	<0.01	<0.01	<0.01
Arkansas	<0.01	<0.01	<0.01	<0.01
Mississippi	<0.01	<0.01	<0.01	<0.01
Vermont	<0.01	<0.01	<0.01	<0.01
Louisiana	<0.01	<0.01	<0.01	<0.01
Rhode Island	<0.01	<0.01	<0.01	<0.01
Texas	<0.01	<0.01	<0.01	<0.01
Canada	0.23	0.20	0.08	0.05

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[29] These states still had significant areas that were not covered by the SO_2 grid. Thus only a fraction of these states' emissions were included in the total state contribution. The following are estimates of the area *not* covered by the SO_2 grid: MO-20%, AR-10%, MS-25%, AL-20%, GA-5%.

Figure 4-14. Ranked state percent sulfate contributions to Northeast Class I receptors based on emissions times upwind probability (E x UP) results

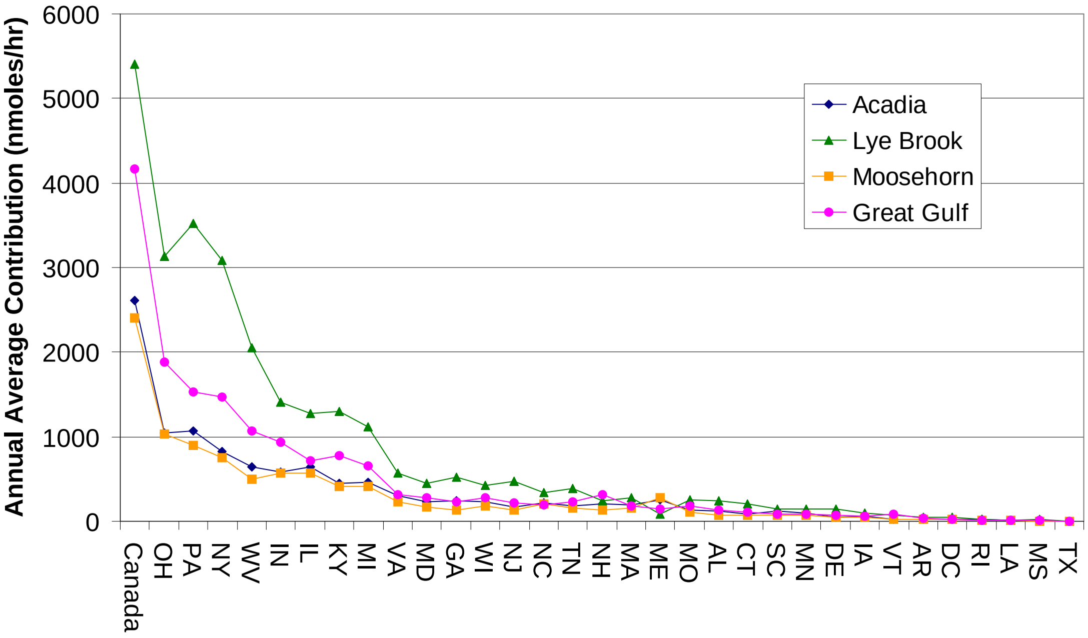
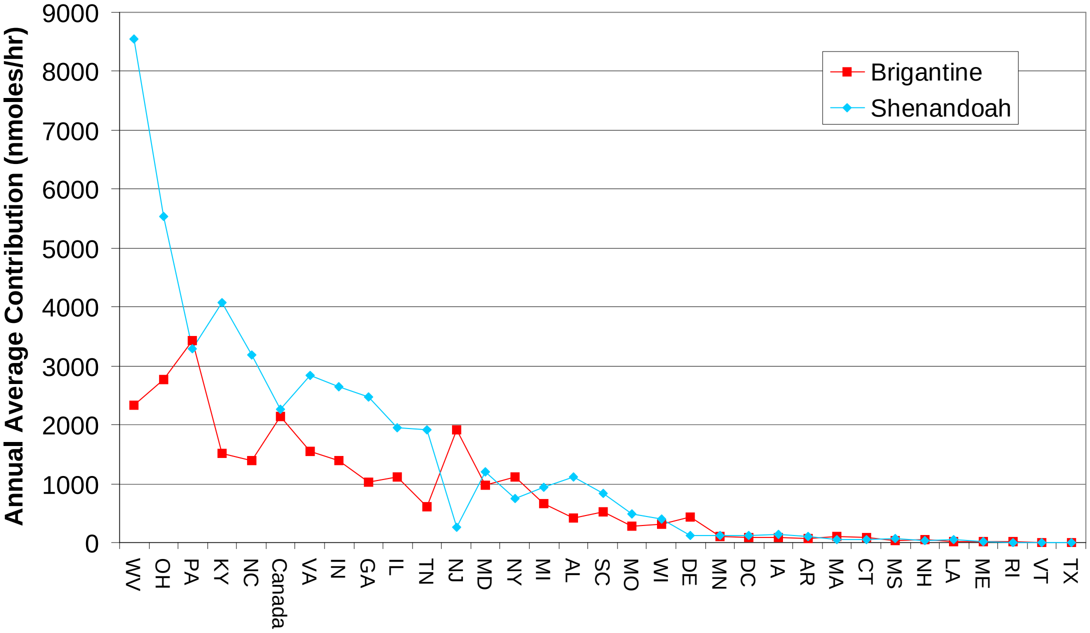


Figure 4-15. Ranked state percent sulfate contributions to Mid-Atlantic Class I receptors based on emissions times upwind probability (E x UP) results



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USEPA, *National Air Pollutant Trends, 1900 – 1998*, EPA 454/R-00-002, available online: http://www.epa.gov/ttn/chief/trends/trends98/trends98.pdf, 2000b.

USEPA 2005, http://www.epa.gov/ttn/chief/eiinformation.html.

5. DATA ANALYSIS TECHNIQUES

Trajectory analyses have historically been used to trace the path of polluted air masses prior to their arrival at a given receptor site. Such analyses, by linking downwind measurements of ambient air quality with specific geographic areas upwind, can be very helpful in exploring the relative contribution of transported emissions from potential source regions on high and low pollution days. As with all of the tools and modeling techniques discussed in this report, trajectory analysis is not without some uncertainties and limitations. One such limitation is the fact that these analyses are typically unable to distinguish emission contributions from one point along the length of the trajectory from a different point along the path. In addition, the accuracy of any individual back trajectory calculation for a single observation or episode may be compromised by inherent limitations in the underlying Lagrangian trajectory models, which tend to become less accurate as the calculation progresses further back in time. Fortunately, a variety of techniques are available to mitigate these uncertainties and enhance confidence in the results obtained using trajectory analysis. These include techniques for triangulating results across multiple sites, ensemble techniques that combine the results of large numbers of back trajectories, clustering algorithms that group similar trajectories based on their spatial characteristics, and techniques for combining trajectory analyses with source apportionment models. All of these strategies can be useful in improving and refining traditional trajectory analyses.

This chapter describes the results of back trajectory analyses that have been conducted to date for key pollutant species observed at MANE-VU and nearby receptor sites. In addition, we explore novel techniques for improving the accuracy of individual trajectories by grouping meteorologically similar back-trajectories into trajectory "clusters" and examining the relationship between the transport pathways defined by these clusters and downwind air quality observations. We then turn to source apportionment models which can be used to group available monitoring data for various components of $PM_{2.5}$ in logical combinations that best explain the variation in observed species concentrations in terms of specific "source profiles." These source profiles are used to distinguish the emissions from common pollution sources (e.g., mobile sources, coal combustion). The information obtained through source apportionment analysis can then be used in combination with back trajectory analysis to link specific geographic source regions with downwind air quality conditions and to establish the relative contribution of different source regions to visibility impacts at the receptor site.

This chapter provides further description of several trajectory analysis techniques, before proceeding to a review of the insights gained to date by applying these techniques to analyze source regions for particulate pollution in the MANE-VU region. Preliminary results and interpretation are presented and used to support and bolster the basic conceptual model of regional haze outlined in Chapter 2.

5.1. Trajectory Analysis

The Hybrid Single Particle Lagrangian Integrated Trajectory (HYSPLIT) model (Draxler, 1997 and 1998) was used to calculate back trajectories for 13 sites in the northeastern United States. Most of these sites are located in Class I areas that are subject to the Haze Rule, but several others are located in areas where potential nonattainment with the $PM_{2.5}$ NAAQS warrant analysis. Back trajectories were calculated eight times per day for starting heights of 200, 500, and 1,000 meters above ground level using meteorological wind fields for the five-year period from 2000 through 2004. Meteorological data from the National Oceanic and Atmospheric Administration (NOAA) Air Resources Laboratory (ARL) archives were used. These include wind fields from the Eta Data Assimilation System (EDAS), which cover North America with an 80 km spatial resolution and are based on 3-hourly variational analyses (Rolph, 2003). For the analyses presented here, we exclusively used the 500 meter EDAS trajectories from the baseline period (2000-2004).

Each trajectory was matched with corresponding monitoring data collected as close in time as possible to the “start” time of the back trajectory calculation. The analysis included ambient measurements for $PM_{2.5}$ and ozone (O_3), as well as all particulate matter constituents that are routinely measured as part of the IMPROVE program.

The resulting database of air quality monitoring results and associated back trajectories was used to develop several statistical measures of the probability or likelihood that a given upwind source region is associated with good or poor air quality at the receptor sites analyzed. Appendix A provides a detailed description of the metrics that were developed for this purpose and how they were calculated using both traditional trajectory analysis and cluster analysis techniques. This appendix also provides site-specific results.

5.1.1. Incremental Probability

The incremental probability (IP) field represents a measure of the likelihood that a given source region contributes more than “average” to high concentrations of a particular pollutant at a downwind receptor site (see Appendix A for a more complete definition). This technique can also be used to identify locations that are *less* likely to contribute to poor air quality at a given receptor site, thus allowing for more robust conclusions to be drawn about likely source regions for individual fine particle constituents.

Calculating IP fields for a subset of back trajectories within a complete sample can help further illuminate the different roles of different source regions. For example, it is interesting to note distinct differences between the IP field for back trajectories corresponding to the 10 percent highest observed sulfate values in the Northeast (three sites are shown that bracket the MANE-VU region’s Class I sites) and the IP field for trajectories corresponding to the lowest sulfate values in the Northeast (specifically, sulfate values in the lowest 10th percentile). Figure 5-1 and Figure 5-2 illustrate the IP fields for each set of observations, respectively.

In Figure 5-1 and Figure 5-2, note that the red color indicates areas with greater probability of contributing to transport on the selected days. These show that the very highest observed sulfate values across the region are strongly associated with transport from a source region that encompasses the Ohio River Valley, western Pennsylvania, and the urban East Coast corridor. On the days with the lowest measured sulfate, transport is associated with northwesterly winds from Canada and weather patterns off the Atlantic.

Figure 5-1. Incremental Probability (Top 10% Sulfate) at Acadia, Brigantine and Lye Brook 2000-2004

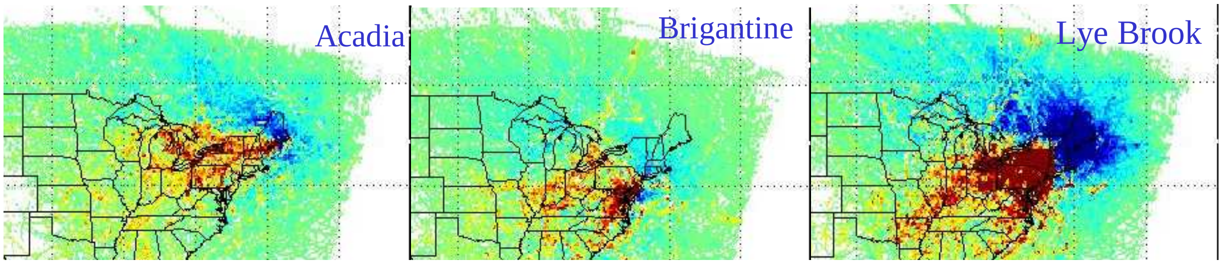
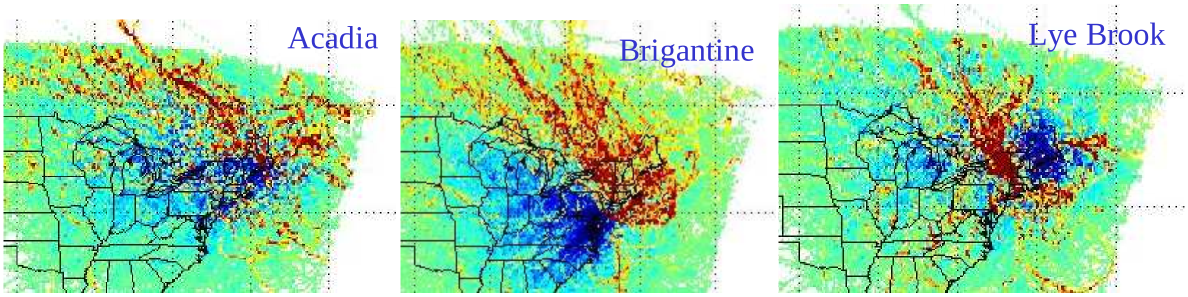


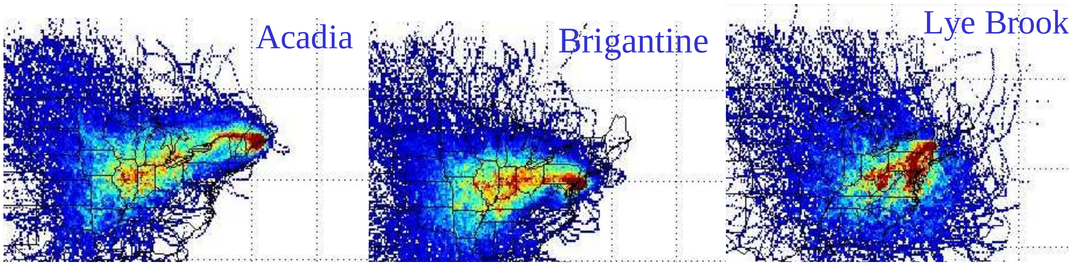
Figure 5-2. Incremental Probability (Bottom 10% Sulfate) at Acadia, Brigantine and Lye Brook 2000-2004



5.1.2. Clustered Back-Trajectories

Each of the IP fields shown in Figure 5-1 or Figure 5-2 incorporate results from over 14,000 back trajectories over the five-year period analyzed. In cases like these, where IP fields are calculated from a very large set of data points, the error in the calculation of any individual trajectory — which can be as high as 30 percent or more of the total transport distance involved in a given trajectory — is not likely to affect the overall result. Assuming that such errors are randomly distributed (i.e., no systematic bias exists in the calculations used by the trajectory model to calculate wind speed or direction), the use of large numbers of individual trajectories will effectively ensure that the random errors cancel out. To further minimize the effect of any errors with respect to individual trajectories, it is also possible to cluster large numbers of back trajectories according to their three-dimensional similarity (see Appendix A for a detailed description of several methodologies used). Figure 5-3 shows residence-time probability fields for clusters of similar back trajectories grouped according to their proximity to unique meteorological pathways. This metric yields probabilistic representations of the meteorological pathways which were most likely to be associated with the highest observed sulfate concentrations at the receptor site. Such probabilistic representations reduce the reliance on any one back trajectory and ensure that the general pattern used to associate a transport pathway with a downwind receptor site is more likely to be accurate.

Figure 5-3. Proximity based cluster with the highest associated sulfate value for three sites in the MANE-VU region, Acadia (sulf=3.19 $\mu g/m^3$), Brigantine (sulf=6.79 $\mu g/m^3$), and Lye Brook (sulf=3.92 $\mu g/m^3$)



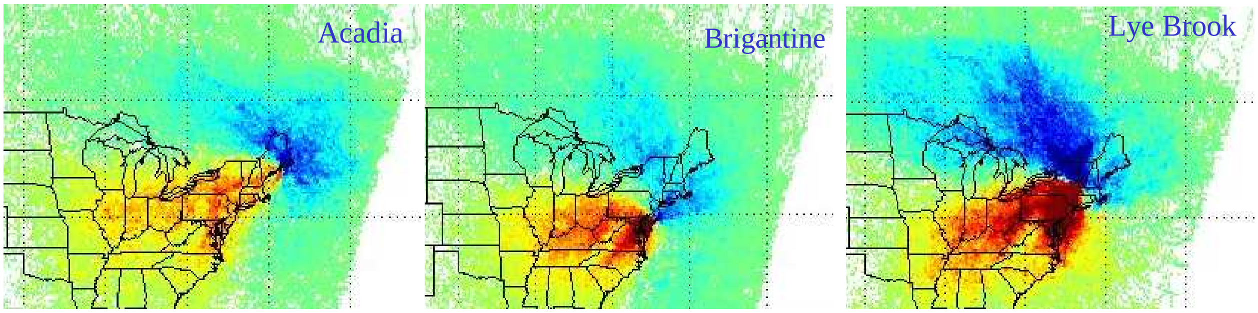
5.1.3. Cluster-Weighted Probability

The clusters derived above can be used individually or combined in an "ensemble cluster" approach similar to how individual trajectories are combined to develop the IP metric. This second method for associating transport patterns with downwind pollution measurements involves using all clusters generated by the clustering algorithms described in the preceding section (and in detail in Appendix A) and weighting them by their average observed sulfate value. Simply averaging the residence-time probability of all clusters would yield the "everyday" probabilities that are used in calculating IP fields. Instead, weighting each cluster *before* the averaging process serves to highlight transport patterns that are associated with high sulfate levels at the receptor site, while downplaying patterns that are associated with low values. Figure 5-4 shows the resulting cluster-weighted probability (CWP) field. Results are similar to those obtained using the incremental probability metric described previously, but they now include all clusters, not just the high-day values.

A noteworthy feature of the clustering process is that while it reduces uncertainty about prevailing transport patterns, it is not helpful in taking advantage of weather variations to identify specific source regions. Thus, results for a particular site should be interpreted as showing that observed air quality conditions have an increased probability of being associated with the transport of a specific pollutant, as opposed to being associated with a particular source region for a given pollutant. Put another way, it is difficult to make an association with a specific point along the pathway defined by a cluster. As with the IP approach described earlier, however, multi-site averaging can address this ambiguity by making it possible to triangulate on regions that are associated with the transport of pollution to multiple sites in different locations, as shown in Figure 5-4.

Both trajectory-based approaches (i.e., IP and CWP) have also been applied to Class I receptor sites in the nearby VISTAS region, which includes the Dolly Sods and Otter Creek Wilderness Areas in West Virginia as well as Shenandoah National Park and the James River Face Wilderness Area in Virginia. Results for the VISTAS Class I sites are presented at the conclusion of Appendix A.

Figure 5-4. Cluster Weighted Probability at Acadia, Brigantine and Lye Brook 2000-2004



5.2. Source Apportionment Models and Ensemble Trajectory Analysis of Source Apportionment Results

Previous sections of this chapter have discussed a category of receptor-based assessment techniques known more generally as ensemble trajectory analysis. The latter category includes residence time analysis (RTA) as well as potential source contribution function (PSCF) and cluster analysis (see also Appendix A). In this section we turn to multivariate mathematical models for analyzing source contributions, such as chemical mass balance (CMB) models, principal component analysis (PCA), positive matrix factorization (PMF), and UNMIX.

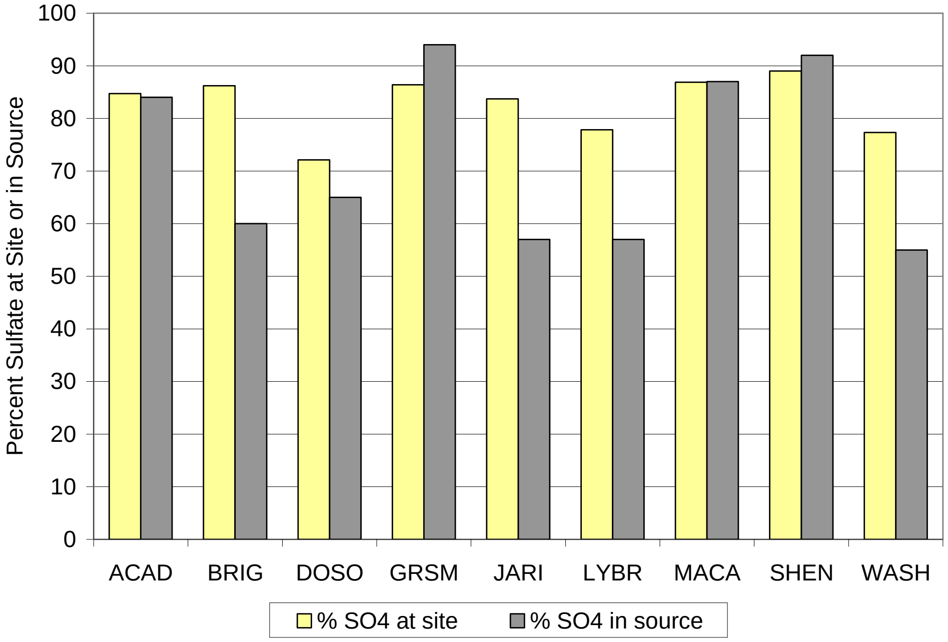
Receptor-based models begin with ambient air quality measurements at one or more receptor locations and work “backward” to identify logical combinations of pollutant species that best fit a “source profile.” Sources matching that profile are assumed to have contributed to the ambient pollutant concentrations historically observed at the receptor locations. These models are typically driven by variations in PM constituent concentrations across multiple observations at one or more sites. An advantage of PCA, PMF, and UNMIX is that source profiles do not need to be known in advance; however, this does mean that the results must be subjectively interpreted to identify and distinguish likely sources.

Because of these complexities and because the multivariate models typically rely entirely on measurements of PM constituents without regard to meteorology, it can be extremely useful to consider results obtained through the ensemble trajectory techniques (which rely on meteorology only) when interpreting or evaluating the outputs from a multivariate modeling exercise.

Appendix B provides details of numerous source apportionment and associated ensemble back trajectory analyses. These details cover results obtained for many of the most significant components of fine particulate mass and resulting light extinction. Here we focus on the “secondary sulfate” or “coal” source profile that was identified at nearly every site in the eastern United States. Secondary sulfate typically accounts for 30–60 percent of overall fine particle mass and 60–80 percent of visibility impairment on the haziest days in the Northeast.

Figure 5-5 shows results from one of the broadest studies conducted to date of sulfate sources and characteristics at nine eastern IMPROVE sites. The bars on the left show the fraction of total sulfate measured at each site that is contributed by the "sulfate/coal" source profile as determined by the source apportionment models. The bars on the right show the fraction of each "sulfate/coal" source profile that is composed of sulfate. Figure 5-5 suggests that: (1) large sources contribute 70–90 percent of the total sulfate measured at the sites, and (2) that the contribution from these large sources consists of 50–90 percent sulfate.

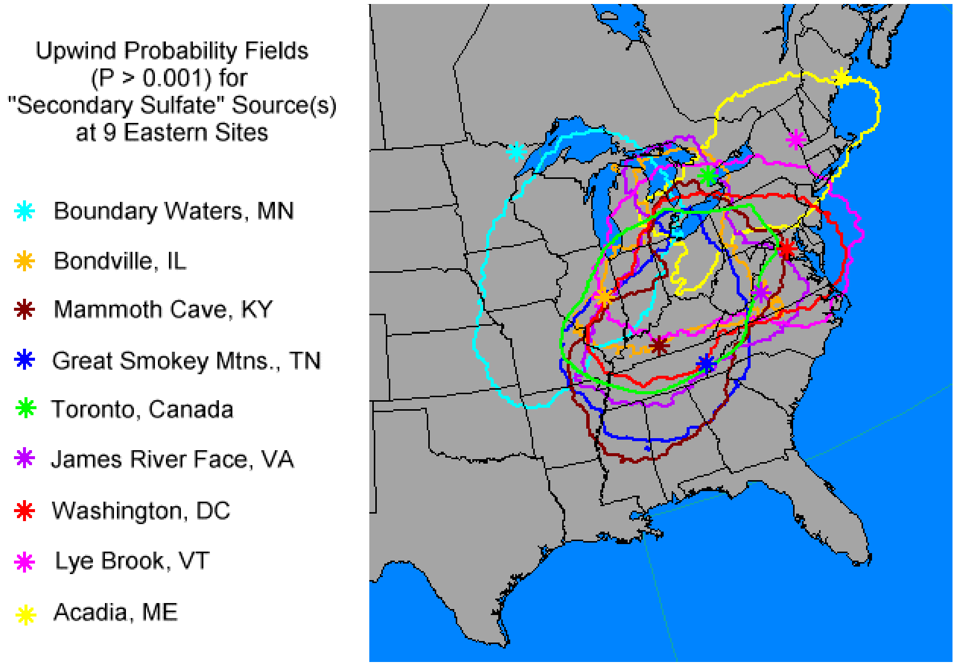
Figure 5-5. Sulfate characteristics of "secondary sulfate" (coal) sources identified at eastern sites



When large sulfate sources are associated with upwind states or regions through the use of back trajectories (Figure 5-6), it becomes clear that many Class I and urban sites in MANE-VU and adjoining areas are influenced by a common source region. These findings suggest that reductions in coal-related SO_2 emissions would have substantial benefits in terms of improved visibility and reduced PM concentrations over a large part of the eastern United States and eastern Canada.

This conclusion is further reinforced by comparing regions with significant emissions that match the "source profiles" generated by available mathematical modeling tools to regions identified through trajectory analysis as having a high probability of being upwind on days with high sulfate levels and high reconstructed extinction values. As shown in Figure 5-6, the degree of correspondence between these regions is substantial. This indicates that the "secondary sulfate/coal combustion" source profile prominent at several eastern sites is strongly linked to regions associated with the highest 10 percent of recorded sulfate and reconstructed extinction values. It is noteworthy that the upwind regions identified in Figure 5-7 are derived from measurements spanning the entire IMPROVE network, suggesting that the source region for "secondary sulfate/coal combustion," which is a dominant contributor to visibility impairment in parts of the eastern United States, is also a major contributor to observed sulfate and extinction outside the MANE-VU region.

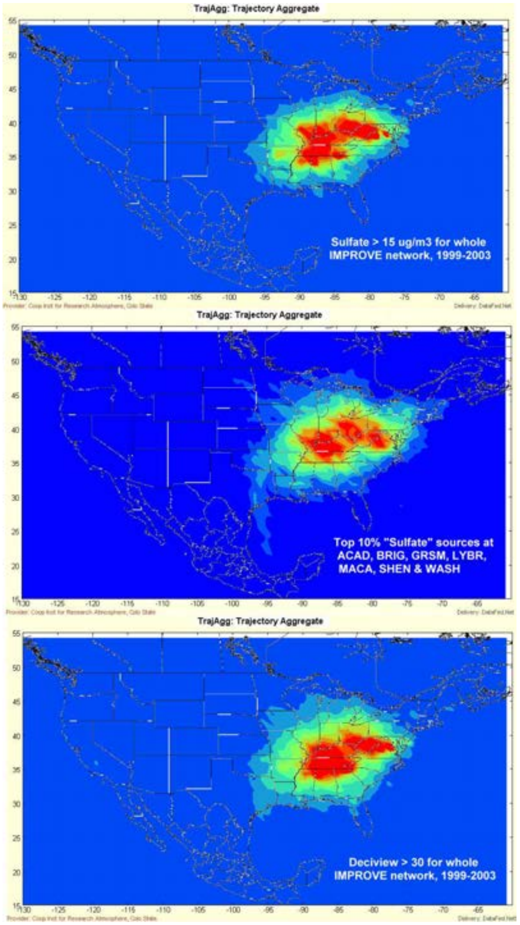
Figure 5-6. Incremental Probabilities for "Secondary Sulfate" (Coal) Sources in Eastern U.S.



5.3. Trajectory Model Evaluation and Future Work

The geographical correspondence exhibited in Figure 5-7 extends to the multi-site average IP fields calculated for the MANE-VU region and shown previously in Figure 5-1. It also extends to the multi-site average IP field calculated using the ATAD model and shown in Figure B-30 in Appendix B. Essentially, both figures are versions of the same thing, but they do exhibit some subtle differences. These differences are highlighted in Figure 5-8 which compares the results of ATAD and HYSPLIT IP calculations for the top 10 percent of sulfate, selenium, and nickel observations at Lye Brook, Vermont. Sulfate is a secondary pollutant that tends to peak in the summer, whereas nickel and selenium are primary pollutants that typically peak in the wintertime. Ni and Se serve as excellent markers for residual oil and coal combustion respectively. The figure indicates strong agreement between the two models in terms of

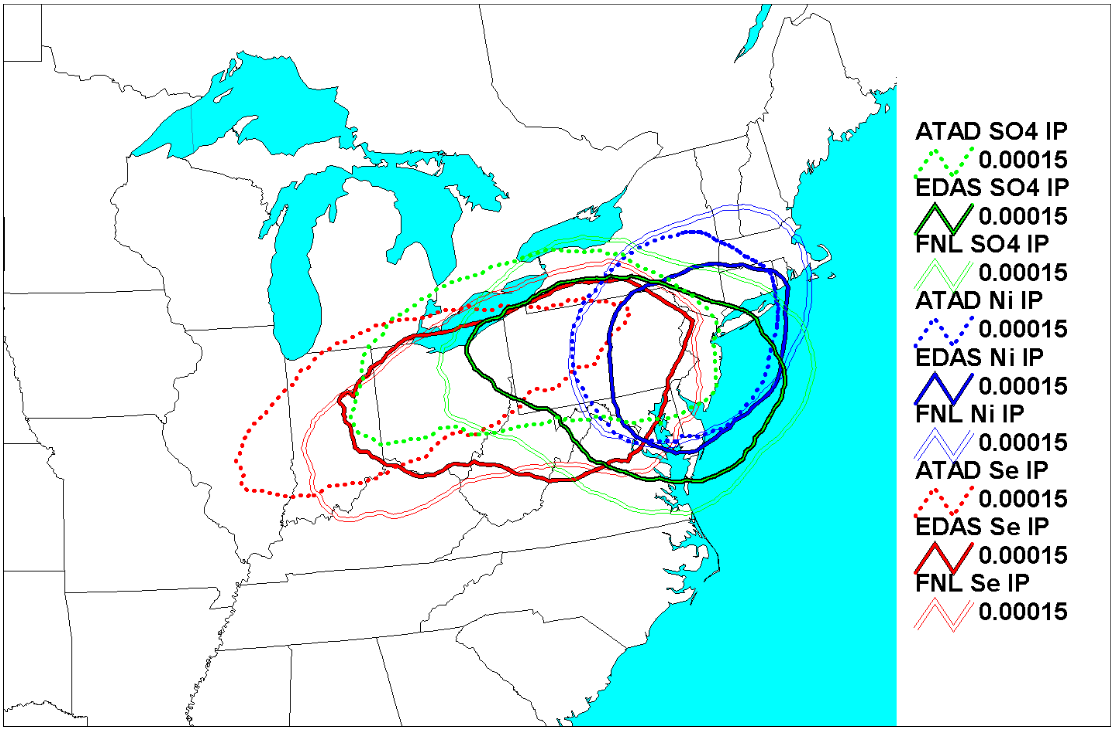
Figure 5-7. Comparison of probability fields for observed sulfate, "sulfate" source profiles for seven eastern sites and reconstructed deciviews



the IP fields they calculate for nickel, suggesting that — during wintertime — primary pollutants are tracked well by both techniques. There is less agreement between the IP fields for sulfate, suggesting either a southerly bias to the HYSPLIT calculations for this secondary pollutant, or a westerly bias to the ATAD results.

Seasonal differences in the meteorology that affects Lye Brook and other East Coast sites during the summer versus during the winter may help to explain these model discrepancies. Some of the largest absolute differences between the ATAD and HYSPLIT estimates occur for the highest sulfate days. While there are many differences between the models, one key difference is in their trajectory start heights. The HYSPLIT trajectories all start at 500 meters above ground level while the ATAD model first estimates a “transport layer depth” (TLD) and then initiates the trajectory (while constraining subsequent trajectory endpoints) at a point roughly half way between ground level and the TLD. During summer, when the largest sulfate events occur, the resulting ATAD start heights are roughly twice as high as the 500 m HYSPLIT start heights (see Figure 5-9). Hence the ATAD calculations tend to extend over a greater distance to the west, while the summer HYSPLIT trajectories may be more reflective of flows that are nearer the surface and more frequently east of the Appalachian Mountains. Both flow regimes are important. In fact, Blumenthal et al. (1997) have observed that the highest ozone concentrations in the Northeast (which often coincide with episodes of high sulfate concentrations) tend to occur when surface flows up the Northeast urban corridor combine with synoptic flows over the Appalachian Mountains from the west, a pattern that is often accompanied by lower level nocturnal jets along the Northeast corridor and through gaps in the Appalachians.

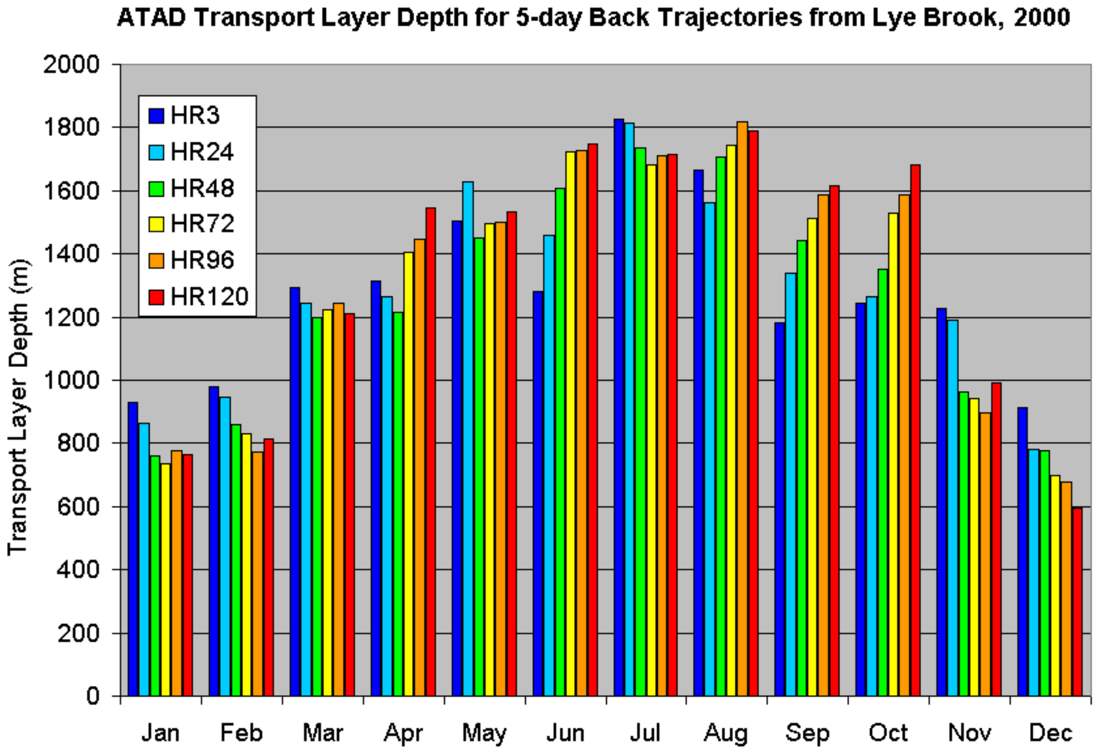
Figure 5-8. Comparison of IP contours generated by ATAD and HYSPLIT (both EDAS and FNL) for sulfate, nickel and selenium at Lye Brook



An extensive evaluation of the performance of HYSPLIT, ATAD, and Capita Monte Carlo trajectory models using a variety of different meteorological drivers, ensemble trajectory techniques, and performance tracers was recently conducted as part of the Big Bend Regional Aerosol and Visibility Observational (BRAVO) study (Pitchford et al., 2004). No one model consistently out-performed the others at that site, hence results from these and more sophisticated photochemical grid models (REMSAD and CMAQ) were merged to produce a best-estimate, "consensus" apportionment of sulfate in the BRAVO study.

MANE-VU is using all available trajectory models, trajectory-related metrics, and improved understanding of transport phenomena to further explore and support the development of emission control strategies for reducing regional haze.

Figure 5-9. ATAD Transport Layer Depth (TLD) by month. Color indicates the length of time prior to arriving at the receptor.



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6. CHEMICAL TRANSPORT MODELS

Eulerian or "grid" models have traditionally served as the workhorse of air quality planning programs. These tools strive to be comprehensive in accounting for emissions, meteorological dynamics, chemical production, transformation, and destruction as well as wet and dry deposition and microphysical processes. With this degree of sophistication comes attendant uncertainty. Many of the more complex processes (e.g., cloud processes and boundary layer dynamics) are handled through parameterizations that attempt to approximate the real atmosphere at an appropriate level of detail. Chemical transport models for ozone and fine particles have improved markedly over the past several years as various groups have developed competing models and as the different strengths and weaknesses of these models help to shed light on various aspects of the underlying science.

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)[30] and the Regional Modeling System for Aerosols and Deposition (REMSAD).[31] Appendix C provides detailed descriptions of these models and of their use by NESCAUM, together with performance evaluations and preliminary results. A brief overview of the two modeling platforms in terms of their relevance to future SIP work is provided here, along with highlights of the findings.

6.1. Chemical Transport Model (CTM) platforms – Overview

Both REMSAD and CMAQ are being used with a 12 km grid[32] in the eastern U.S. domain (see Figure 6-1(b)). Air quality is modeled on 22 vertical layers with hourly temporal resolution for the entire calendar year 2002. REMSAD has simplified chemistry but allows for emissions tracking of sulfate, nitrate, and mercury through a tagging feature that calculates the contribution of specific sources to ambient concentrations, visibility impacts, and wet or dry deposition. REMSAD has shown good performance when reproducing annual or seasonal statistics for sulfate and mercury chemistry, while CMAQ has shown good performance for multiple species. A new release of CMAQ (version 4.5) may improve performance for sulfate, nitrate and organics over what Appendix C presents and will be used with the quality-assured meteorology and emission inventory inputs described below for final SIP submissions in 2007 or 2008.

Meteorological inputs have been developed by the University of Maryland (UMD) using the Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research (NCAR) Mesoscale Model (MM5) system.[33] A modified Blackadar boundary layer scheme is used as well as physics options including explicit representations of cloud physics with simple ice microphysics (no mixed-phase processes) and the Kain-Fritsch cumulus parameterization.

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[30] See Byun and Ching, 1999.

[31] See ICF/SAI, 2002.

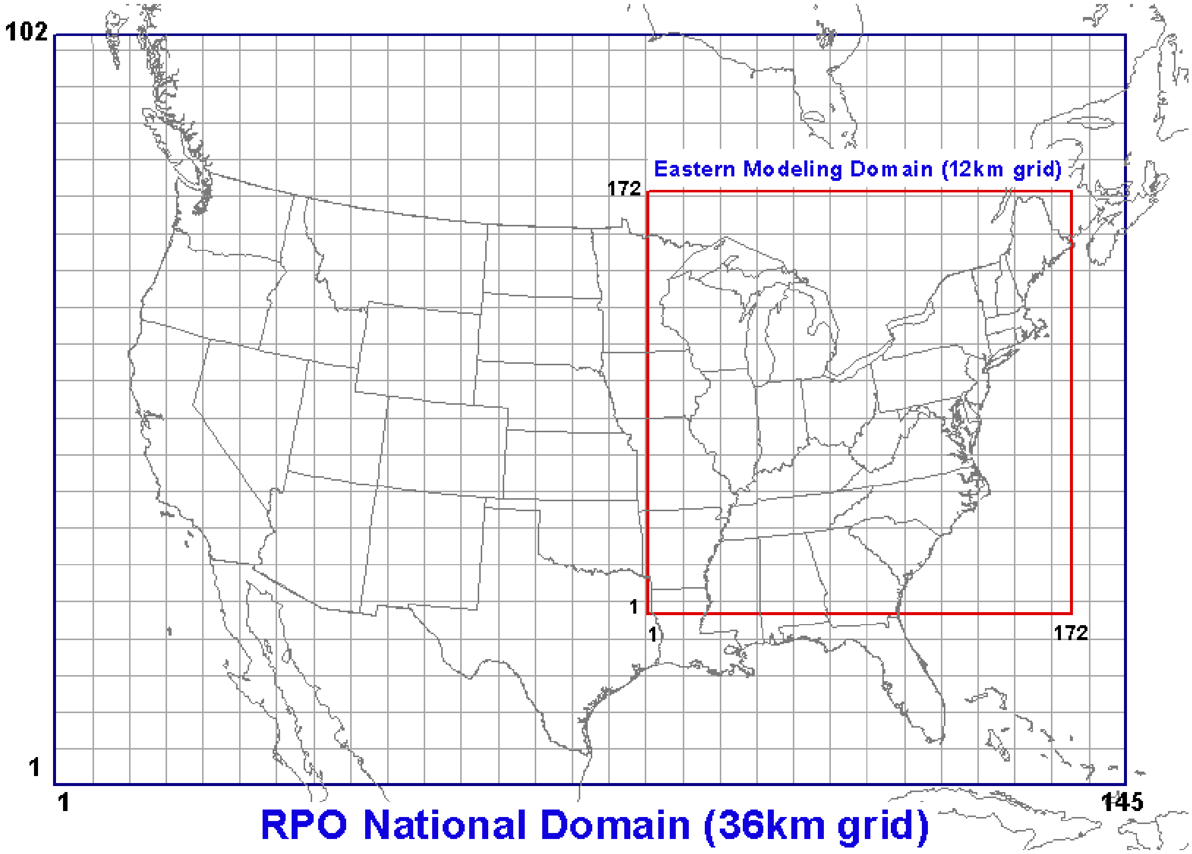
[32] 12 km grid describes a 12 by 12 km grid cell

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

The New York Department of Environmental Conservation and NESCAUM are processing emissions inputs using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System. To model biogenic emissions, SMOKE uses the Biogenic Emission Inventory System, version 2.3 (BEIS2) and version 3.09 and 3.12 (BEIS3). SMOKE has also been integrated with the MOBILE6 model for on-road emissions. MANE-VU has developed a quality-assured 2002 emissions inventory which is being merged with the regional inventories for other RPOs in order to provide a comprehensive emissions inventory for the entire Northeast domain shown in Figure 6-1(b).

A dynamic 3-dimensional boundary condition feeds ambient concentration fields in at the domain boundaries which are representative of actual concentrations during 2002. This dynamic boundary condition was developed by applying the output of a global model run (Park et al., 2004) with 4 degree longitude by 5 degree latitude horizontal resolution at the boundaries of the 36 km grid domain shown in Figure 6-1(a). The results of this annual simulation are then applied at the boundary of our 12km grid domain, ensuring acceptable representation of the general trends and sulfate patterns that were present during the simulation period.

Figure 6-1. Modeling domains used in NESCAUM air quality modeling studies. (a) Domain 1: 36 km National US grid domain with location of 12 km grid domain highlighted; (b) Domain 2: 12km Northeast US grid domain. The gridlines are shown at 180 km intervals (5 x 5 36 km cells or 15 x 15 12 km cells).

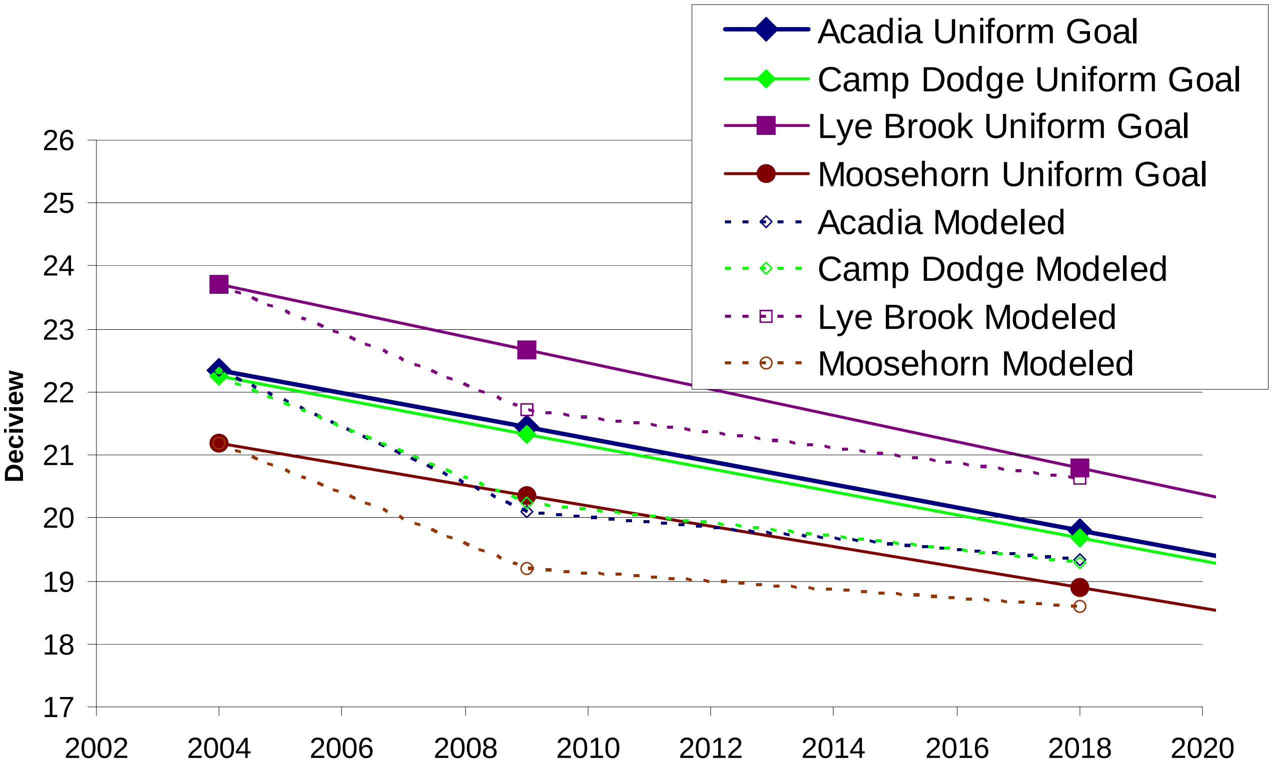


6.2. Preliminary Results

CMAQ has been run for a complete set of baseline simulations including 2002, 2009 and 2018. These preliminary runs are described in greater detail in Appendix C, but include inventory and meteorological drivers which will be updated for final SIP submissions. Nonetheless, these preliminary results suggest that implementation of existing regulations (including USEPA's Clean Air Interstate Rule, or CAIR) will continue to yield significant improvements in visibility over the next decade, primarily as a result of regional sulfate reductions (See Figure 6-2 a and b below for visibility improvement and see Figure C-27 in Appendix C for sulfate mass reductions). Despite these potential improvements, not all MANE-VU Class I areas are anticipated to achieve uniform progress goals as described by current USEPA guidance.[34] Brigantine Wilderness Area in New Jersey is projected to fall about a half deciview short of the uniform rate under existing emission reduction plans.

A significant difference between the CMAQ and the REMSAD results presented here is that NESCAUM has taken the additional step of reprocessing the SO_2 emission sources from each state such that these model inputs are formatted to take advantage of

Figure 6-2(a) and (b): CMAQ Integrated SIP Modeling Platform simulation results for 2002, 2009 and 2018 relative to Uniform Progress Goals calculated according to current USEPA guidance for (a) Northeast Class I sites in MANE-VU and (b) Mid-Atlantic Class I sites in or near MANE-VU.



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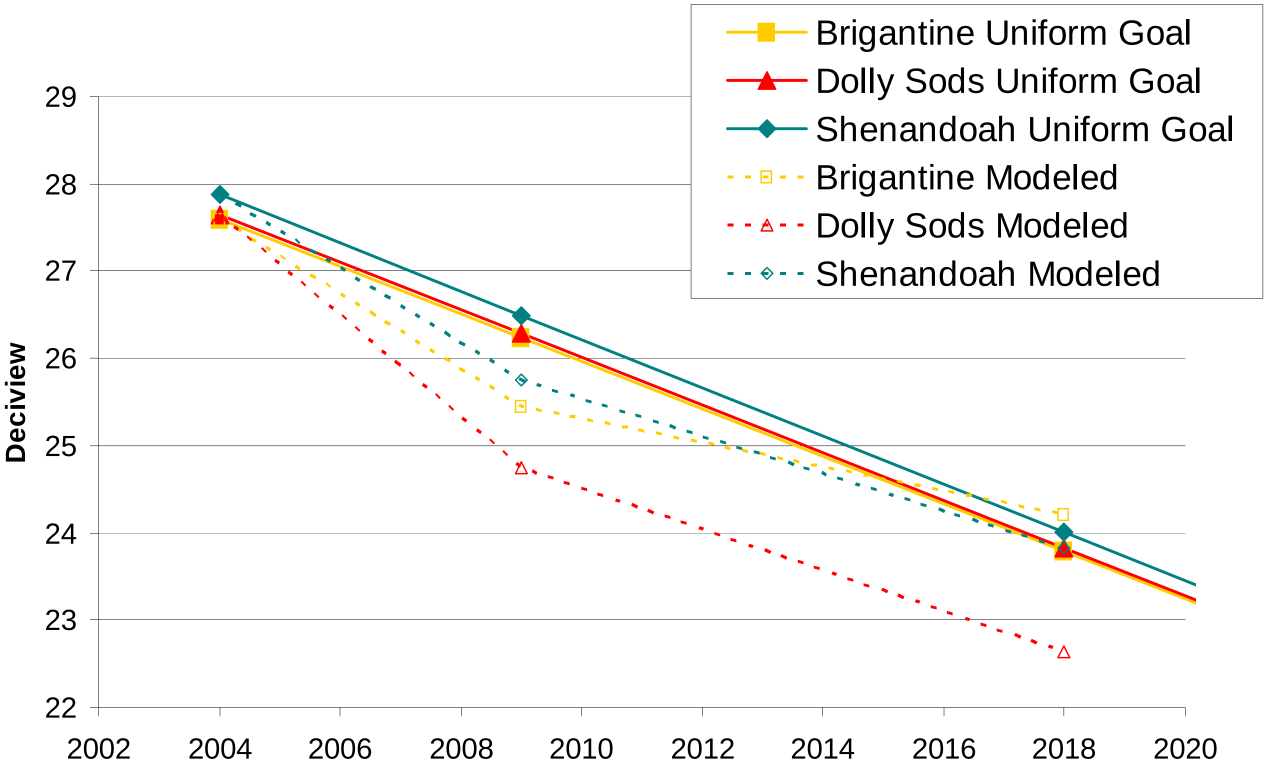
[34] We note that uniform progress goals do not necessarily dictate visibility levels required by statute, but do represent a point of comparison for states when establishing *reasonable* progress goals toward our national visibility goal of no anthropogenic visibility impairment by 2064.

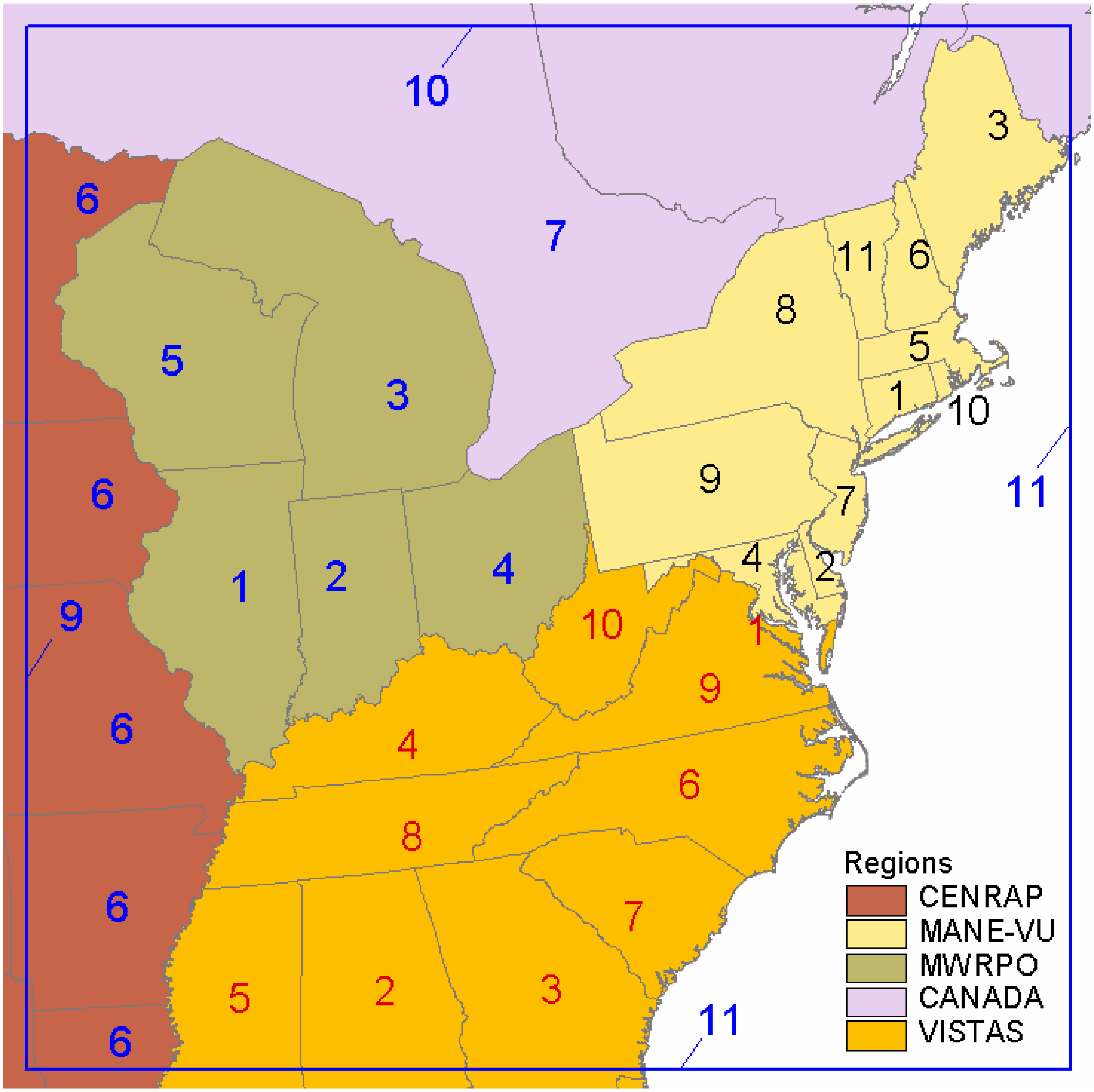
Figure 6-2(b).



REMSAD's tagging capabilities. Thus, all SO_2 emissions included in the model for the eastern half of the country, Canada and the boundary conditions have been tagged according to state of origin. This allows for a rough estimation of the total contribution from elevated point sources in each state to simulated sulfate concentrations at eastern receptor sites. The tagging scheme employed for this analysis is illustrated in Figure 6-3. Using identical emission and meteorological inputs to those prepared for the Integrated SIP (CMAQ) platform, REMSAD was used to simulate the annual average impact of each state's SO_2 emission sources on the sulfate fraction of $PM_{2.5}$ over the northeastern United States.

Results of these tagged runs indicate that elevated point sources in Pennsylvania, Ohio, and New York contribute significantly, on an annual basis, to sulfate concentrations at all MANE-VU sites. Northern sites (e.g., Acadia) are more influenced by sources in upper midwestern states (e.g., Wisconsin and Michigan) whereas southern sites like Brigantine are more influenced by sources in more southerly states such as West Virginia, Maryland, and Virginia. Shenandoah, a VISTAS Class I site appears to be most strongly influenced by sources in Ohio, Pennsylvania, and West Virginia, followed by other nearby Southeast and Midwest states. Figure 6-4 through Figure 6-7 present these results showing the breakout of sulfate by individual tag. Note that the large "other" fraction of sulfate includes all sources outside the analysis domain, which includes some portions of the VISTAS and CENRAP RPO, Northern and Western Canada in addition to all other (i.e., inter-continental) sources of SO_2. Figure 6-8 shows similar results summarized by RPO for the 20% worst days.

Figure 6-3. REMSAD modeling tagging schemes.
(black: group 1, red: group 2, and blue: group 3)



Note: Sulfur species from anthropogenic emission sources are tagged by states for three sets of tags. Tag group 3 also includes boundary conditions. The color of the numbers represents tag groups (black: group 1, red: group 2, and blue: group 3)

Figure 6-4. 2002 Eastern states' contribution to annual PM sulfate in Acadia, ME

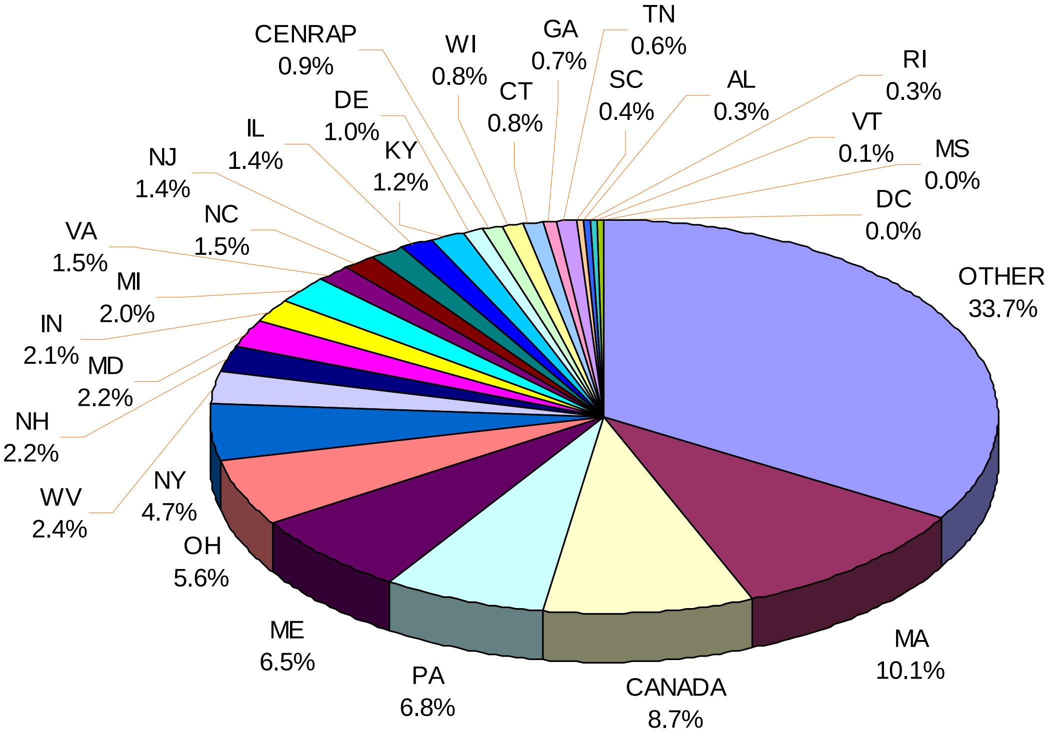


Figure 6-5. 2002 Eastern states' contribution to annual PM sulfate in Brigantine, NJ

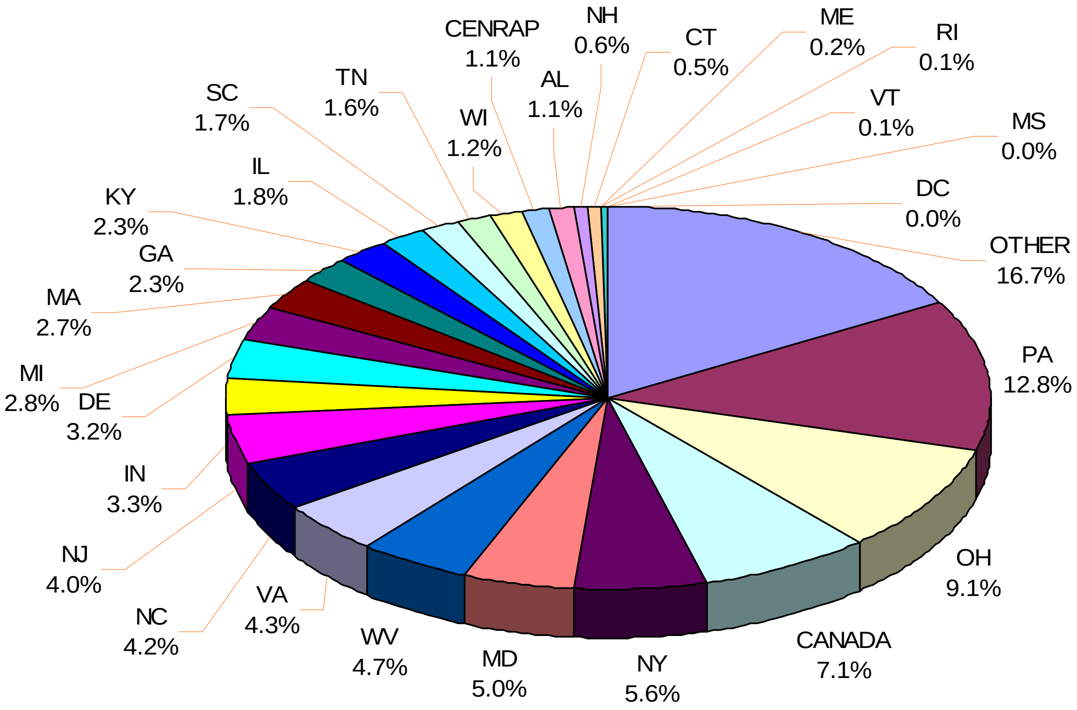


Figure 6-6. 2002 Eastern states' contribution to annual PM sulfate in Lye Brook, VT

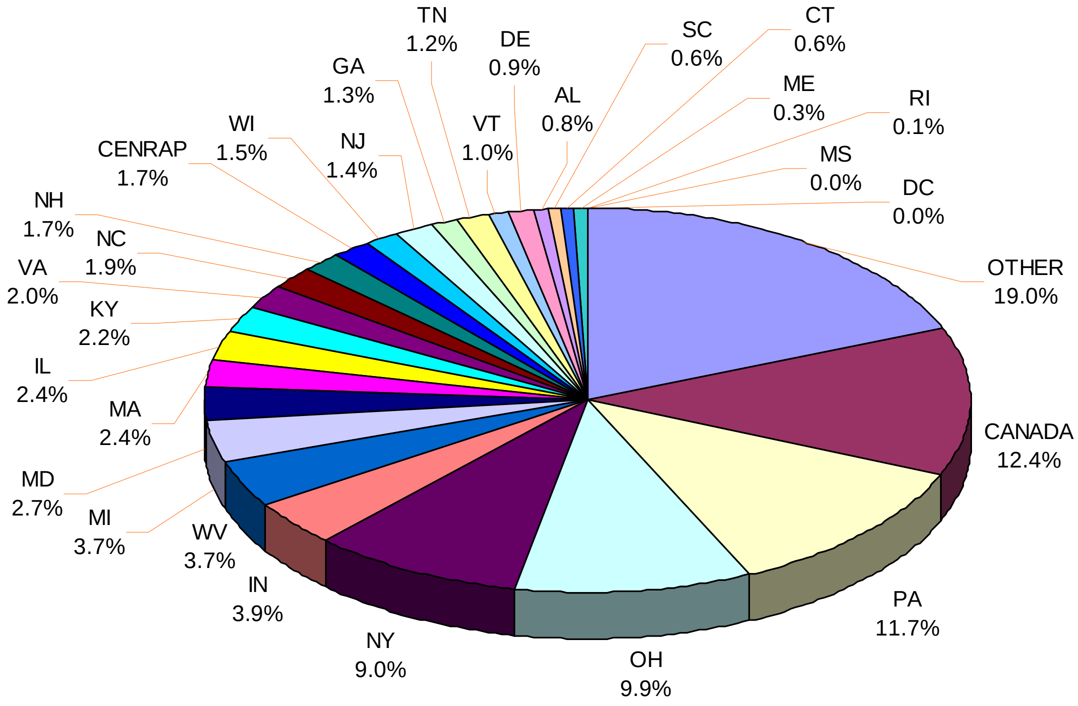


Figure 6-7. 2002 Eastern states' contribution to annual PM sulfate in Shenandoah, VA

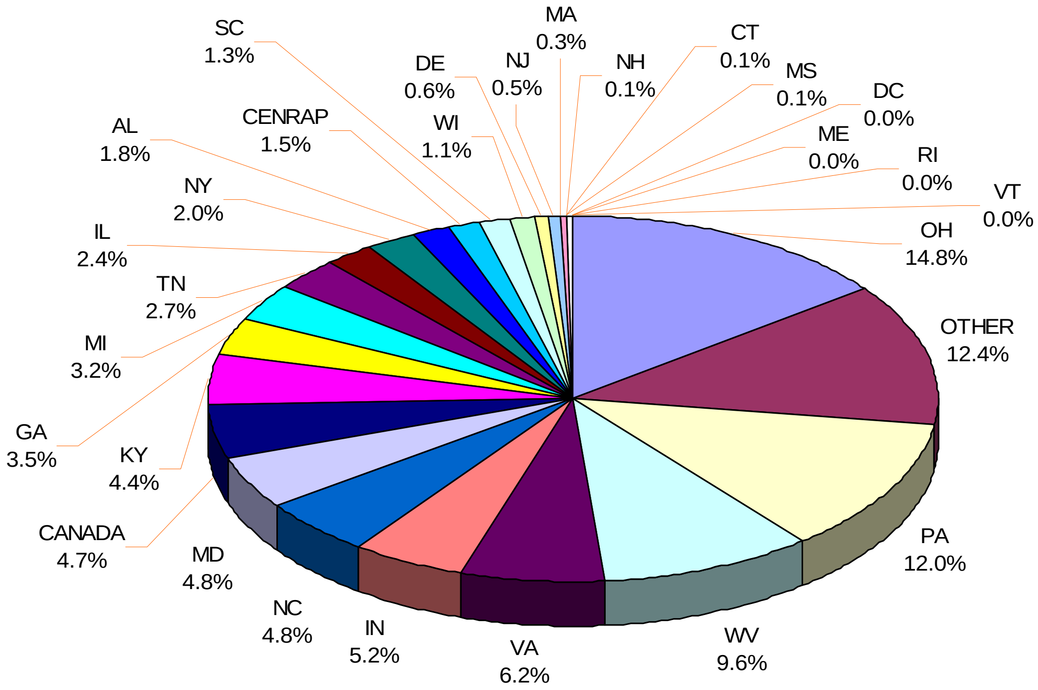
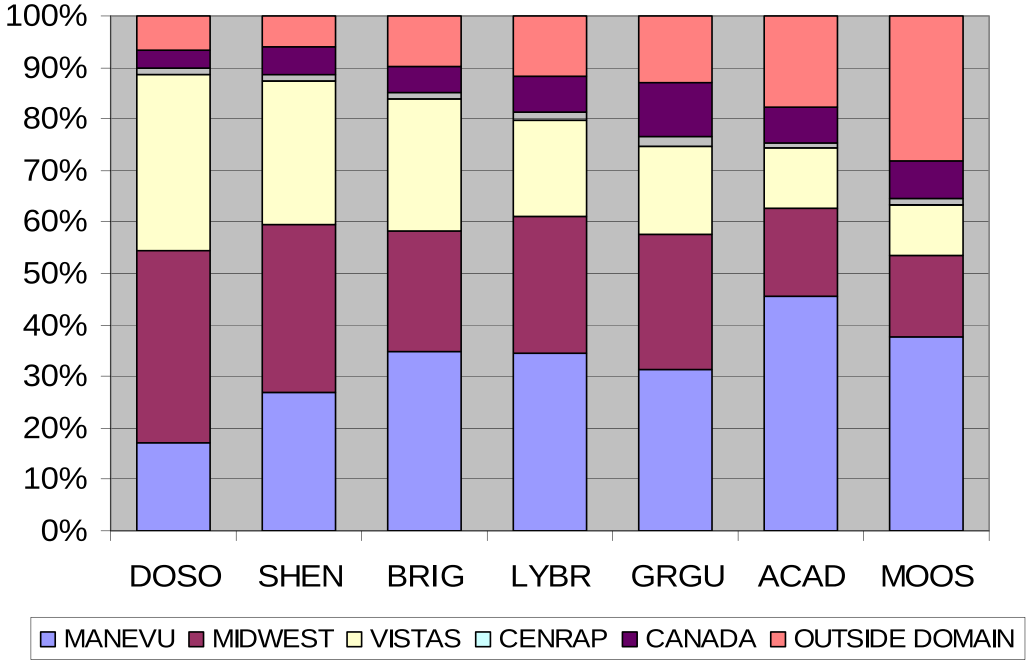


Figure 6-8. Comparison of Sulfate Extinctions on 20% Worst Visibility Days



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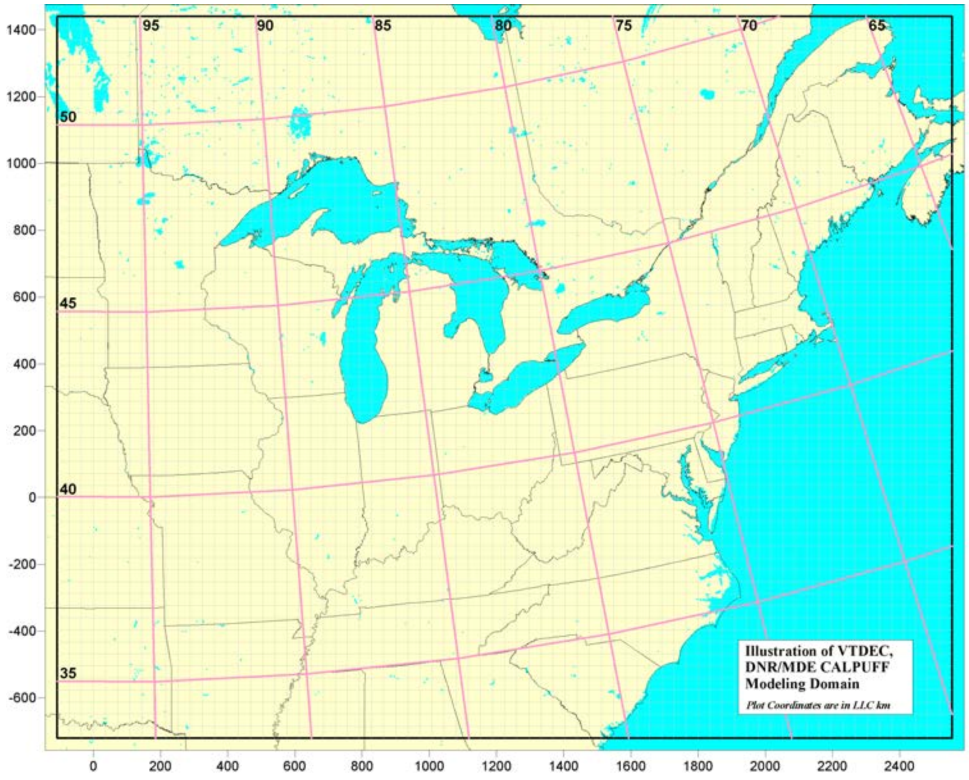
7. LAGRANGIAN DISPERSION MODELS

Dispersion models are commonly used to study the impacts of pollutant plumes or specific point source emissions on surrounding areas. The scale of these models has traditionally been limited to a few hundred kilometers because of a perceived lack of ability to accurately reproduce horizontal dispersion beyond these distances. Recent advances in the CALPUFF system (USEPA, 2006) — including enhancements to its horizontal diffusion and dispersion algorithms as well as the addition of chemical transformation parameterizations — have resulted in improved performance over much greater distances. In fact, the most recent proposed guidance for implementing the BART (Best Available Retrofit Technology) requirements of the Regional Haze Rule provide for the use of CALPUFF to analyze dispersion over distances exceeding 200 km as long as a detailed modeling protocol is included for approval by the appropriate reviewing authority (40 CFR Part 51, pg. 25194, May 5, 2004).

Appendix D provides specific information related to two CALPUFF platforms that have been developed for a large domain (see Figure 7-1) by the Vermont Department of Environmental Conservation (VT DEC) Air Pollution Control Branch and by the State of Maryland's Department of the Environment (MDE) and Department of Natural Resources (MDNR) with contract assistance provided by Environmental Resources Management (ERM). Appendix D contains detailed descriptions of the two platforms; the processing and evaluation of both MM5- and National Weather Service (NWS)-based meteorological data; the processing and evaluation of CEMS (Continuous Emissions Monitoring System)- and 2002 RPO-based emissions data; performance evaluations of

Figure 7-1. CALPUFF modeling domain utilized by MANE-VU



the overall modeling system; preliminary results of modeling to determine annual average and maximum 24-hour impact by individual unit and by state; and discussion of the future application of these platforms to the BART program. This chapter provides an overview of the two modeling platforms, a summary of initial results, and a brief analysis of the differences between the two platforms.

While CALPUFF will certainly play a role in helping MANE-VU assess potential visibility impacts for BART-eligible sources, the development of twin CALPUFF platforms utilizing both MM5-based and NWS-based meteorological drivers further expands the suite of analytical tools available for assessing contributions — at both the facility and state level — to downwind visibility impairment in the MANE-VU region.

7.1. Platform Overview

The VT DEC developed meteorological inputs for CALPUFF using observation-based inputs (i.e., rawinsonde and surface measurements) from the NWS and by applying CALMET. VT DEC also developed hourly emissions and exhaust flow data from the Acid Rain Program's CEMS data files for 869 large electric generating units (EGUs). These emissions data were utilized as inputs to CALPUFF, along with emissions data for four additional source sectors: non-EGU point sources, mobile (on-road), mobile (off-road), and general area sources. The emission inputs for these source sectors were derived from the 2002 RPO inventories.

The MDNR and MDE developed meteorological inputs for CALPUFF using MM5 data developed by the University of Maryland for the MANE-VU and Ozone Transport Commission SIP modeling work. The Maryland agencies utilized the CEMS data files developed by VT DEC, and independently developed emissions and source parameters for the other four source sectors based on the same inter-RPO 2002 inventories.

Both platforms were used to model the entire calendar year 2002. These simulations have been configured to provide estimates for both individual source impacts and cumulative state impacts and to allow for inter-platform comparisons. The modeling domain has been designed to be consistent with the other modeling systems described in this report (e.g., REMSAD, CMAQ), so that conclusions regarding the most significant sources of sulfate-related visibility impacts in MANE-VU can be compared. Consistency across a broad range of approaches will add credibility to the conclusions reached in the overall contribution assessment.

7.2. CALPUFF Modeling Results for Individual Sources

To explore differences between the two CALPUFF modeling platforms, each was used to create a ranked list of the 100 emissions sources that contribute most to ambient sulfate levels at each of several eastern Class I sites. Of the 100 top sources identified for the Brigantine Wilderness Area, 70 sources appeared on the lists generated by both platforms. At Acadia, Lye Brook, and Shenandoah, there was even more agreement between the model results, with both platforms identifying 78, 76, and 85 out of 100 of the same top sources for each of these sites, respectively. Figure 7-2 shows the correlation between estimated annual average impacts for the sources that were identified by both platforms as among the top 100 sulfate contributors. While the

NWS/rawindsonde-based meteorology consistently produced slightly lower estimates of impact than the MM5-based platform, the correlations are relatively robust, ranging from 0.89 at Brigantine to 0.93 at Lye Brook.

Overall, the CALPUFF modeling results to date demonstrate reasonably good comparability between the two platforms (as illustrated by Figure 7-2 and Table 7-1), but they also suggest a consistent pattern of under prediction for one platform relative to the other.

7.3. CALPUFF Modeling Results Overview

Table 7-1 provides further comparisons of the results of CALPUFF modeling utilizing the two different platforms described earlier in this chapter: VT DEC (NWS/rawinsonde-based meteorology) and Maryland (MM5-based meteorology).[35] The table summarizes annual average sulfate concentrations by source category for each of the two platforms relative to observed concentrations.

Table 7-1. CALPUFF Overall Modeling Summary

	Annual Average SO_4 Ion Concentration (µg/m^3)								
	NWS/Rawinsonde-based Meteorology				MM5-based Meteorology				Observed
	CEMS EGU	Non-CEMS Point	Area/Mobile	Total	CEMS EGU	Non-CEMS Point	Area/Mobile	Total	
Shenandoah	2.271	0.412	0.106	2.789	2.98	0.46	0.22	3.66	4.61
Brigantine	1.847	0.421	0.257	2.526	2.6	0.51	0.38	3.48	4.06
Acadia	0.965	0.385	0.218	1.569	1.42	0.42	0.28	2.13	1.86
Lye Brook	1.178	0.342	0.178	1.698	1.65	0.36	0.25	2.26	2.17

Generally, the NWS/rawinsonde platform predicts lower sulfate ion concentrations than the MM5 platform. On an annual average basis, the concentrations predicted using the MM5 platform are much closer to observed values than the concentrations predicted using the NWS/rawindsonde platform.

7.4. CALPUFF Results for Ranked State Sulfate Contributions

This section focuses on the ranked contribution of emissions from individual states to overall sulfate levels at specific receptor sites (additional results are summarized in a number of different ways in Appendix D). The rankings were calculated by summing impacts from EGUs included in the 2002 data base for each state. State contributions are then sorted by total annual impact. Predicted annual average sulfate ion concentrations from other source sectors were added to these data in Table 7-2(a-d) for both platforms. As in previous chapters, estimated contributions to receptor impact by state (using the results presented in Table 7-2) are depicted graphically in Figure 7-3 and Figure 7-4 for the observation-based and MM5-based platforms, respectively. States are ranked along the horizontal axis by averaging the individual results calculated for each state using the two CALPUFF platforms.

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[35] The Maryland Department of the Environment is contributing toward this work through the Maryland Department of Natural Resources and their contractor ERM, Inc. who have developed the MM5-based meteorology and CALPUFF platform.

Figure 7-2. Correlation between MM5-based source contributions (Maryland/ERM) and NWS/rawindsonde-based source contributions (VT DEC) for common EGUs modeled at four receptor sites in or near MANE-VU

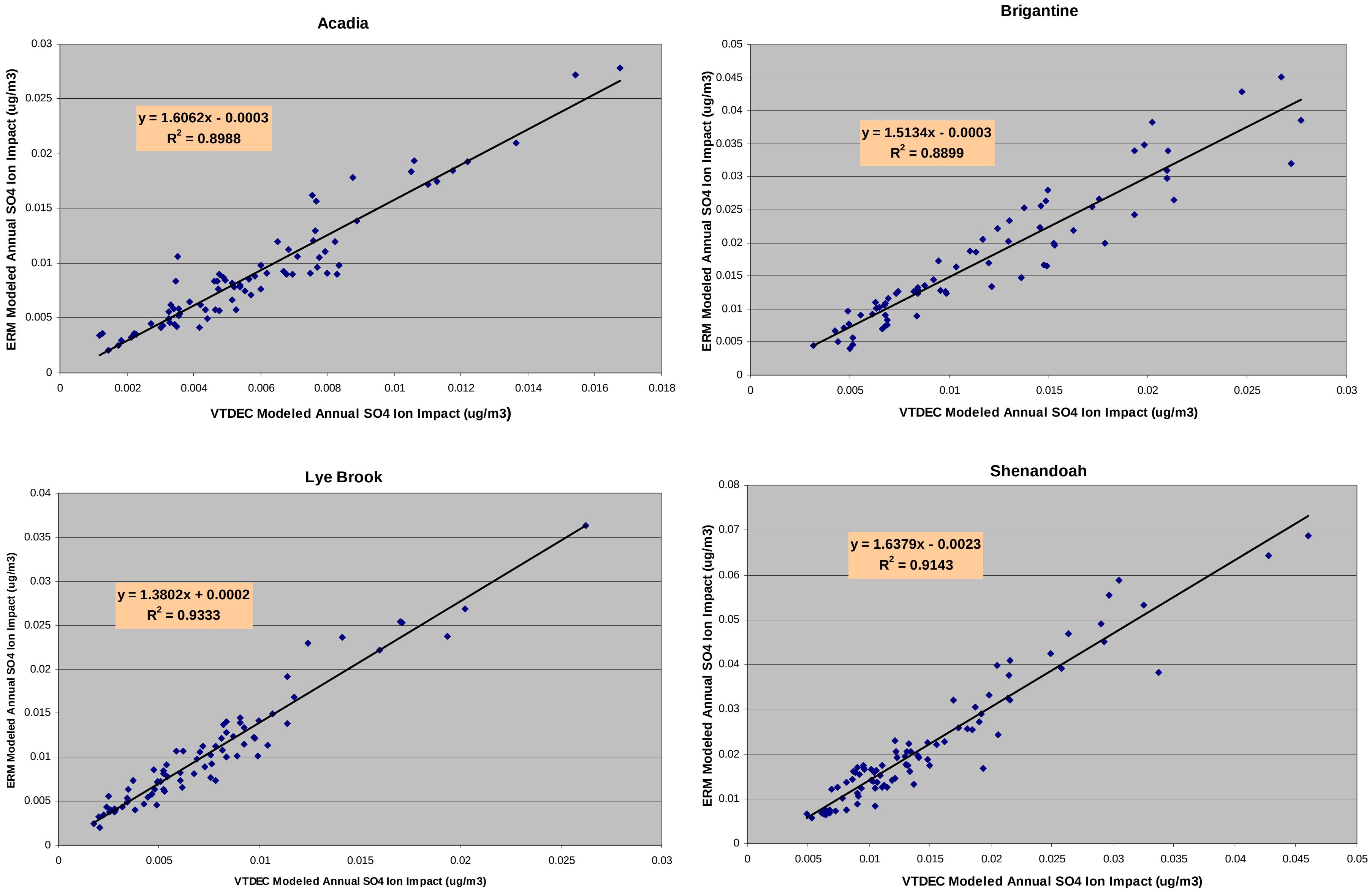


Table 7-2a. Sulfate Ion Impacts by State (Annual Average)
Acadia National Park

	NWS-based Meteorology (VT DEC) µg/m^3				**MM5-based Meteorology (MDE/MDNR) µg/m^3**			
STATE	**CEM PT**	**Non-CEM PT**	**Area/ Mobile**	**TOTAL PT**	**CEM PT**	**Non-CEM PT**	**Area/ Mobile**	**TOTAL**
AL(a)	0.0086	0.0013	0.0003	0.0102	0.0139	0.0009	0.0011	0.0159
AR(a)	0.0039	0	0	0.0039	0.0054	0.0020	0.0010	0.0083
CT	0.0041	0.0012	0.0085	0.0138	0.0074	0.0011	0.0072	0.0156
DC	0.0001	0.0001	0.0002	0.0004	6.9E-05	0.0001	0.0003	0.0005
DE	0.0087	0.002	0.0008	0.0115	0.0093	0.0109	0.0018	0.0219
GA(a)	0.0142	0.0008	0.0005	0.0155	0.0259	0.0009	0.0019	0.0287
IA	0.0097	0.0122	0.0001	0.0219	0.0149	0.0120	0.0030	0.0299
IL	0.0342	0.0157	0.0004	0.0504	0.0486	0.0172	0.0034	0.0693
IN	0.0758	0.0103	0.001	0.087	0.1089	0.0119	0.0099	0.1307
KS(a)	0.0081	0	0	0.0081	0.0137	0.0012	0.0010	0.0159
KY	0.0411	0.0054	0.0023	0.0487	0.0632	0.0038	0.0069	0.0740
MA	0.0653	0.0127	0.0579	0.136	0.0860	0.1544	0.0773	0.3176
MD	0.0398	0.0019	0.0034	0.0451	0.0780	0.0062	0.0040	0.0882
ME	0.0032	0.0243	0.0294	0.057	0.0030	0.0356	0.0236	0.0622
MI	0.0611	0.0083	0.0031	0.0726	0.0656	0.0095	0.0093	0.0844
MN	0.0089	0.0043	0.0005	0.0137	0.0107	0.0022	0.0023	0.0151
MO	0.014	0	0	0.014	0.0215	0.0115	0.0041	0.0371
MS(a)	0	0.0002	0.0002	0.0003	0	0.0002	0.0002	0.0004
NC	0.0342	0.0081	0.0014	0.0437	0.0554	0.0057	0.0019	0.0630
ND(a)					0	0.0009	0.0012	0.0021
NE(a)	0.0017	0	0	0.0017	0.0028	0	0.0009	0.0037
NH	0.0386	0.0022	0.0071	0.0479	0.0666	0.0020	0.0065	0.0750
NJ	0.013	0.0025	0.0076	0.0232	0.0187	0.0033	0.0133	0.0354
NY	0.0577	0.0118	0.0505	0.12	0.0736	0.0363	0.0578	0.1677
OH	0.1402	0.0081	0.0013	0.1496	0.2248	0.0457	0.0055	0.2759
OK(a)	0.0059	0	0	0.0059	0.0071	0.0015	0.0006	0.0092
PA	0.1383	0.0196	0.0126	0.1706	0.2354	0.0214	0.0156	0.2725
RI	0	0	0.0074	0.0074	5.9E-06	0.0007	0.0043	0.0050
SC	0.0092	0.003	0.001	0.0132	0.0134	0.0036	0.0012	0.0182
SD(a)	0.0009	0	0	0.0009	0.0012	2.8E-05	0.0009	0.0022
TN	0.0192	0.0045	0.0024	0.0261	0.0286	0.0076	0.0031	0.0393
TX(a)	0	0	0	0	1.1E-05	0	2.3E-05	3.5E-05
VA	0.0319	0.0082	0.0007	0.0407	0.0389	0.0081	0.0029	0.0499
VT	0	0.0004	0.0169	0.0173	4.0E-06	0.0004	0.0026	0.0030
WI	0.0152	0.0196	0.0005	0.0353	0.0254	0.0085	0.0019	0.0358
WV	0.0583	0.0053	0.0006	0.0642	0.0865	0.0086	0.0016	0.0966
Canada(b)	0	0.1914	0	0.1914				
Totals	**0.96511**	**0.3854**	**0.21832**	**1.5688**	**1.45**	**0.44**	**0.28**	**2.17**

Notes:

(a) Only sources in that portion of the state within the RPO modeling domain were modeled.

(b) 52 Canadian point sources > 250 tons/yr SO_2 emissions during 2002 (from Canadian NPRI).

Table 7-2b. Sulfate Ion Impacts by State (Annual Average)
Brigantine Wilderness Area

	NWS-based Meteorology (VT DEC) μg/m^3				**MM5-based Meteorology (MDE/MDNR) μg/m^3**			
STATE	**CEM PT**	**Non-CEM PT**	**Area/ Mobile**	**TOTAL PT**	**CEM PT**	**Non-CEM PT**	**Area/ Mobile**	**TOTAL**
AL(a)	0.0317	0.0055	0.0011	0.0383	0.0304	0.0017	0.0020	0.0341
AR(a)	0.0047	0	0	0.0047	0.0088	0.0032	0.0017	0.0137
CT	0.0041	0.0013	0.0099	0.0153	0.0044	0.0009	0.0063	0.0116
DC	0.0009	0.0004	0.0008	0.0021	0.0012	0.0005	0.0013	0.0030
DE	0.0395	0.0111	0.0073	0.0579	0.0524	0.0549	0.0138	0.1211
GA(a)	0.0576	0.0044	0.0030	0.0649	0.0672	0.0024	0.0057	0.0753
IA	0.0156	0.0176	0.0001	0.0333	0.0152	0.0137	0.0032	0.0321
IL	0.0521	0.0192	0.0005	0.0719	0.0535	0.0190	0.0043	0.0768
IN	0.1165	0.0125	0.0011	0.1302	0.1632	0.0162	0.0128	0.1921
KS(a)	0.0113	0	0	0.0113	0.0107	0.0009	0.0008	0.0124
KY	0.0846	0.0098	0.0039	0.0982	0.1285	0.0076	0.0135	0.1496
MA	0.0240	0.0049	0.0191	0.0480	0.0234	0.0406	0.0168	0.0808
MD	0.1351	0.0073	0.0165	0.1589	0.2191	0.0228	0.0210	0.2630
ME	0.0004	0.0017	0.0016	0.0037	0.0002	0.0017	0.0011	0.0030
MI	0.0579	0.0077	0.0028	0.0685	0.0810	0.0110	0.0120	0.1040
MN	0.0120	0.0056	0.0007	0.0183	0.0114	0.0025	0.0027	0.0166
MO	0.0179	0	0	0.0179	0.0202	0.0108	0.0036	0.0346
MS(a)	0	0.0006	0.0003	0.0009	0	0.0006	0.0005	0.0012
NC	0.1414	0.0360	0.0060	0.1835	0.1609	0.0160	0.0054	0.1823
ND(a)					0	0.0011	0.0015	0.0026
NE(a)	0.0031	0	0	0.0031	0.0025	0	0.0009	0.0035
NH	0.0064	0.0004	0.0012	0.0080	0.0100	0.0003	0.0010	0.0113
NJ	0.0426	0.0081	0.0518	0.1024	0.0625	0.0124	0.0805	0.1553
NY	0.0658	0.0120	0.0719	0.1497	0.0810	0.0307	0.0779	0.1896
OH	0.2611	0.0130	0.0017	0.2757	0.4297	0.0836	0.0088	0.5221
OK(a)	0.0068	0	0	0.0068	0.0077	0.0014	0.0007	0.0098
PA	0.2538	0.0460	0.0339	0.3336	0.4407	0.0553	0.0461	0.5421
RI	0	0	0.0042	0.0042	2.1E-06	0.0003	0.0016	0.0019
SC	0.0362	0.0139	0.0042	0.0542	0.0341	0.0101	0.0032	0.0475
SD(a)	0.0011	0	0	0.0011	0.0012	3.4E-05	0.0012	0.0024
TN	0.0477	0.0138	0.0049	0.0664	0.0630	0.0188	0.0061	0.0879
TX(a)	0	0	0	0	2.5E-07	0	2.9E-05	3.0E-05
VA	0.1442	0.0447	0.0035	0.1924	0.1577	0.0331	0.0119	0.2027
VT	0	0.0002	0.0033	0.0035	1.5E-06	0.0001	0.0006	0.0008
WI	0.0216	0.0312	0.0007	0.0535	0.0315	0.0106	0.0026	0.0447
WV	0.1499	0.0118	0.0016	0.1633	0.2340	0.0202	0.0046	0.2588
Canada(b)	0	0.0807	0	0.0807				
Totals	**1.84732**	**0.42121**	**0.25746**	**2.526**	**2.61**	**0.51**	**0.38**	**3.49**

Notes:

(a) Only sources in that portion of the state within the RPO modeling domain were modeled.

(b) 52 Canadian point sources > 250 tons/yr SO_2 emissions during 2002 (from Canadian NPRI).

Table 7-2c. Sulfate Ion Impacts by State (Annual Average)
Lye Brook Wilderness Area

	NWS-based Meteorology (VT DEC) µg/m^3				**MM5-based Meteorology (MDE/MDNR) µg/m^3**			
STATE	**CEM PT**	**Non-CEM PT**	**Area/ Mobile**	**TOTAL PT**	**CEM PT**	**Non-CEM PT**	**Area/ Mobile**	**TOTAL**
AL(a)	0.0151	0.0023	0.0005	0.0179	0.0209	0.0013	0.0015	0.0238
AR(a)	0.0053	0	0	0.0053	0.0072	0.0029	0.0015	0.0116
CT	0.0015	0.0004	0.0038	0.0057	0.0024	0.0006	0.0045	0.0075
DC	0.0001	0.0002	0.0003	0.0005	7.9E-05	0.0002	0.0004	0.0006
DE	0.0045	0.0017	0.0007	0.0068	0.0076	0.0123	0.0020	0.0219
GA(a)	0.0270	0.0016	0.0011	0.0296	0.0351	0.0012	0.0029	0.0392
IA	0.0151	0.0175	0.0001	0.0326	0.0184	0.0158	0.0041	0.0383
IL	0.0473	0.0173	0.0005	0.0651	0.0550	0.0208	0.0047	0.0805
IN	0.1039	0.0120	0.0011	0.1170	0.1369	0.0148	0.0128	0.1645
KS(a)	0.0115	0	0	0.0115	0.0167	0.0016	0.0013	0.0195
KY	0.0647	0.0075	0.0031	0.0753	0.0820	0.0047	0.0099	0.0967
MA	0.0106	0.0040	0.0125	0.0270	0.0161	0.0291	0.0203	0.0655
MD	0.0452	0.0025	0.0040	0.0518	0.0686	0.0088	0.0052	0.0826
ME	0.0001	0.0020	0.0017	0.0038	0.0003	0.0024	0.0018	0.0044
MI	0.0841	0.0113	0.0041	0.0995	0.0798	0.0121	0.0120	0.1039
MN	0.0130	0.0062	0.0007	0.0200	0.0147	0.0031	0.0035	0.0213
MO	0.0191	0	0	0.0191	0.0253	0.0140	0.0052	0.0445
MS(a)	0	0.0004	0.0002	0.0006	0	0.0006	0.0004	0.0011
NC	0.0424	0.0088	0.0016	0.0528	0.0680	0.0058	0.0022	0.0760
ND(a)					0	0.0014	0.0020	0.0035
NE(a)	0.0027	0	0	0.0027	0.0032	0	0.0012	0.0044
NH	0.0072	0.0007	0.0020	0.0098	0.0137	0.0008	0.0023	0.0167
NJ	0.0071	0.0017	0.0051	0.0139	0.0128	0.0029	0.0115	0.0272
NY	0.0637	0.0289	0.0586	0.1511	0.0985	0.0613	0.0842	0.2440
OH	0.2108	0.0112	0.0016	0.2237	0.2963	0.0649	0.0078	0.3690
OK(a)	0.0086	0	0	0.0086	0.0097	0.0020	0.0009	0.0127
PA	0.1918	0.0255	0.0169	0.2342	0.3050	0.0288	0.0219	0.3558
RI	0	0	0.0013	0.0013	1.4E-06	0.0002	0.0010	0.0012
SC	0.0088	0.0037	0.0013	0.0138	0.0133	0.0040	0.0014	0.0187
SD(a)	0.0014	0	0	0.0014	0.0017	4.3E-05	0.0014	0.0031
TN	0.0281	0.0065	0.0032	0.0378	0.0407	0.0098	0.0042	0.0546
TX(a)	0	0	0	0	8.4E-06	0	3.2E-05	4.0E-05
VA	0.0295	0.0088	0.0008	0.0391	0.0454	0.0104	0.0037	0.0596
VT	0	0.0006	0.0499	0.0505	4.0E-06	0.0017	0.0083	0.0100
WI	0.0229	0.0293	0.0007	0.0529	0.0351	0.0116	0.0028	0.0495
WV	0.0852	0.0079	0.0009	0.0939	0.1232	0.0121	0.0023	0.1375
Canada(b)	0	0.1211	0	0.1211				
Totals	**1.1780**	**0.3416**	**0.1781**	**1.6977**	**1.65**	**0.36**	**0.25**	**2.27**

Notes:

(a) Only sources in that portion of the state within the RPO modeling domain were modeled.

(b) 52 Canadian point sources > 250 tons/yr SO_2 emissions during 2002 (from Canadian NPRI).

Table 7-2d. Sulfate Ion Impacts by State (Annual Average)
Shenandoah National Park

	NWS-based Meteorology (VT DEC) µg/m^3				**MM5-based Meteorology (MDE/MDNR) µg/m^3**			
STATE	**CEM PT**	**Non-CEM PT**	**Area/ Mobile**	**TOTAL PT**	**CEM PT**	**Non-CEM PT**	**Area/ Mobile**	**TOTAL**
AL(a)	0.0521	0.0084	0.0018	0.0623	0.0504	0.0029	0.0034	0.0567
AR(a)	0.0074	0	0	0.0074	0.0087	0.0035	0.0019	0.0141
CT	0.0005	0.0002	0.0011	0.0018	0.0007	0.0001	0.0009	0.0017
DC	0.0004	0.0004	0.0008	0.0016	8.1E-05	0.0003	0.0009	0.0013
DE	0.0101	0.0029	0.0011	0.0141	0.0086	0.0136	0.0021	0.0243
GA(a)	0.0879	0.0056	0.0040	0.0975	0.0963	0.0032	0.0079	0.1073
IA	0.0192	0.0181	0.0001	0.0374	0.0152	0.0130	0.0036	0.0318
IL	0.0646	0.0222	0.0006	0.0874	0.0561	0.0189	0.0045	0.0794
IN	0.1782	0.0156	0.0015	0.1952	0.1907	0.0181	0.0155	0.2243
KS(a)	0.0137	0	0	0.0137	0.0091	0.0007	0.0006	0.0104
KY	0.1273	0.0135	0.0057	0.1465	0.1741	0.0106	0.0184	0.2031
MA	0.0036	0.0005	0.0020	0.0060	0.0029	0.0047	0.0023	0.0098
MD	0.1045	0.0116	0.0118	0.1280	0.1365	0.0373	0.0109	0.1847
ME	0	0.0004	0.0003	0.0007	2.8E-05	0.0003	0.0002	0.0006
MI	0.0830	0.0082	0.0036	0.0948	0.0860	0.0100	0.0125	0.1085
MN	0.0148	0.0055	0.0007	0.0210	0.0109	0.0023	0.0028	0.0160
MO	0.0255	0	0	0.0255	0.0180	0.0104	0.0034	0.0318
MS(a)	0	0.0009	0.0004	0.0013	0	0.0010	0.0007	0.0017
NC	0.1669	0.0251	0.0050	0.1970	0.2257	0.0148	0.0062	0.2467
ND(a)					0	0.0011	0.0016	0.0027
NE(a)	0.0038	0	0	0.0038	0.0023	0	0.0009	0.0032
NH	0.0010	0.0001	0.0002	0.0012	0.0013	5.3E-05	0.0002	0.0016
NJ	0.0102	0.0018	0.0046	0.0166	0.0119	0.0022	0.0071	0.0212
NY	0.0350	0.0027	0.0141	0.0519	0.0468	0.0141	0.0167	0.0776
OH	0.4678	0.0256	0.0027	0.4960	0.6483	0.1088	0.0114	0.7685
OK(a)	0.0080	0	0	0.0080	0.0081	0.0016	0.0009	0.0105
PA	0.2774	0.0354	0.0214	0.3342	0.4517	0.0318	0.0247	0.5082
RI	0	0	0.0004	0.0004	3.1E-07	2.9E-05	0.0002	0.0002
SC	0.0242	0.0117	0.0041	0.0401	0.0232	0.0093	0.0035	0.0359
SD(a)	0.0011	0	0	0.0011	0.0011	4.0E-05	0.0014	0.0025
TN	0.0781	0.0207	0.0073	0.1061	0.0929	0.0304	0.0086	0.1319
TX(a)	0	0	0	0	1.7E-07	0	3.2E-05	3.2E-05
VA	0.1102	0.0398	0.0047	0.1547	0.1124	0.0469	0.0263	0.1856
VT	0	0	0.0006	0.0007	3.6E-07	2.6E-05	0.0001	0.0002
WI	0.0259	0.0311	0.0007	0.0577	0.0289	0.0096	0.0026	0.0410
WV	0.2691	0.0259	0.0045	0.2995	0.4657	0.0402	0.0111	0.5170
Canada(b)	0	0.0781	0	0.0781				
Totals	**2.271**	**0.412**	**0.106**	**2.789**	**2.98**	**0.46**	**0.22**	**3.66**

Notes:

(a) Only sources in that portion of the state within the RPO modeling domain were modeled.

(b) 52 Canadian point sources > 250 tons/yr SO_2 emissions during 2002 (from Canadian NPRI).

Figure 7-3a. Ranked state percent sulfate contributions to Northeast Class I receptors based on observation-based (VT) CALPUFF results

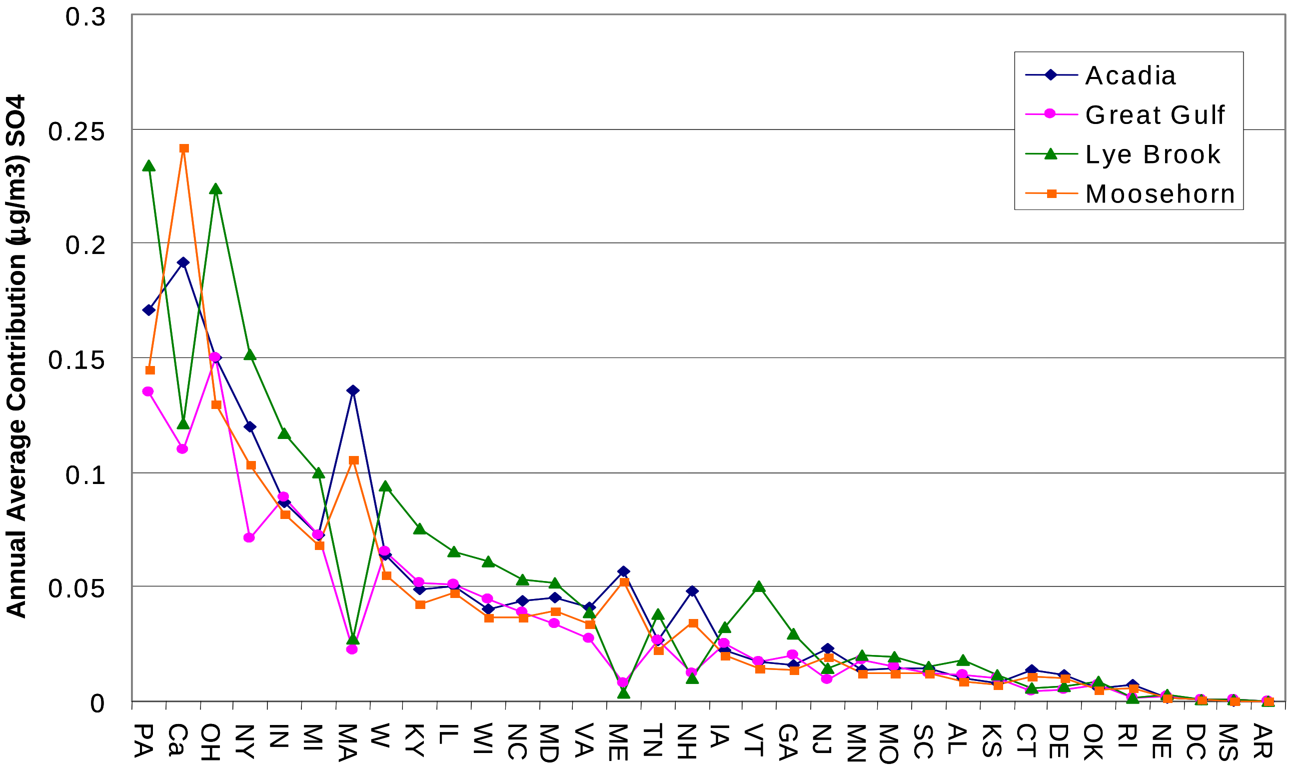


Figure 7-3b. Ranked state percent sulfate contributions to Mid-Atlantic Class I receptors based on observation-based (VT) CALPUFF results

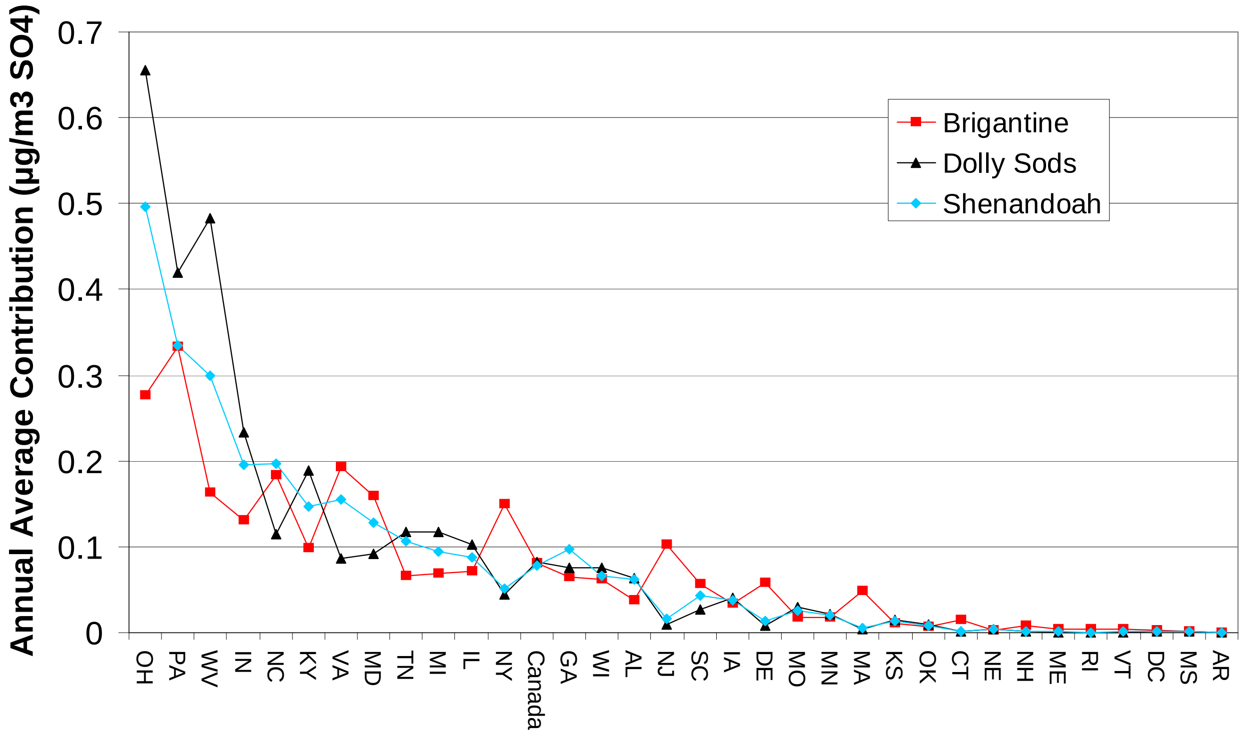


Figure 7-4a. Ranked state percent sulfate contributions to Northeast Class I receptors based on MM5-based (MD) CALPUFF results

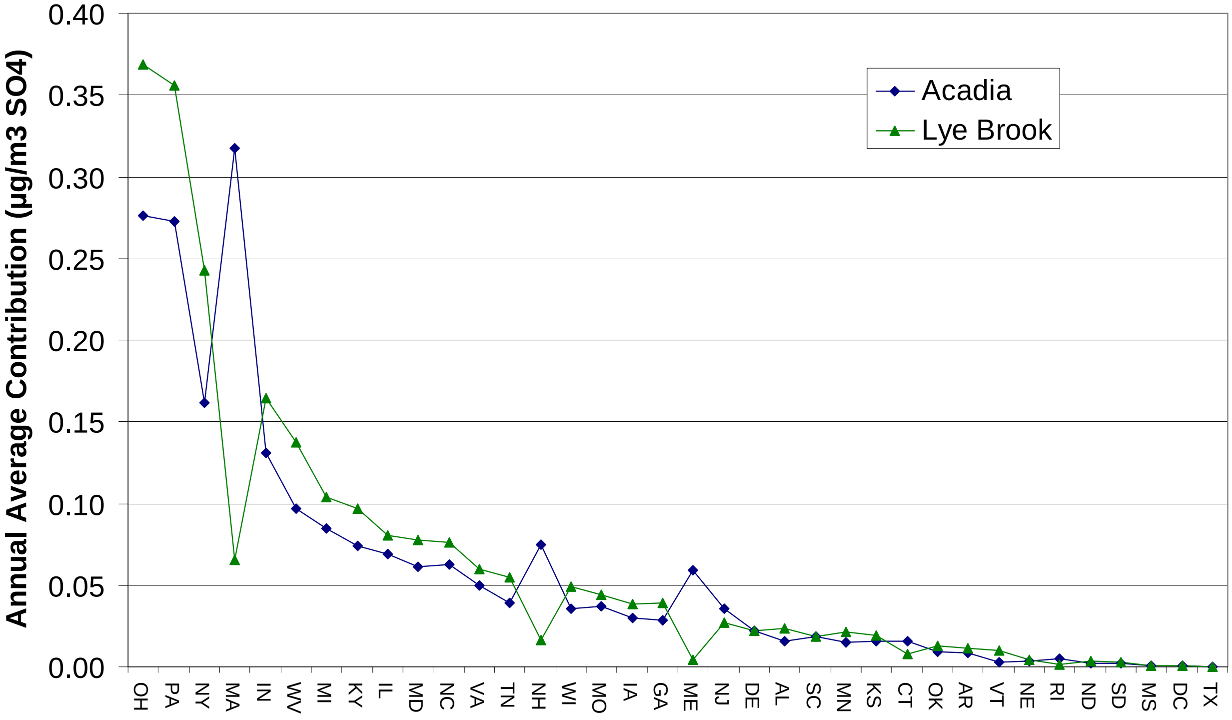
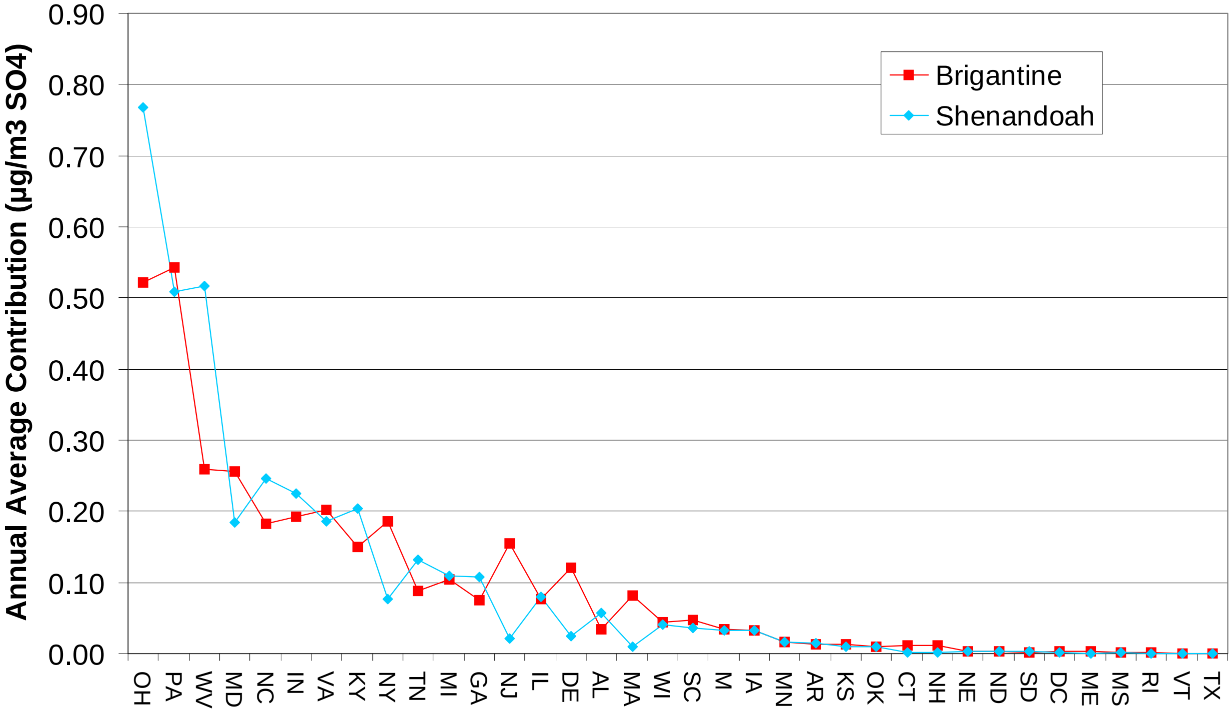


Figure 7-4b. Ranked state percent sulfate contributions to Mid-Atlantic Class I receptors based on MM5-based (MD) CALPUFF results



7.5. Future work and potential uses of CALPUFF results for BART determinations

Modeling efforts to date have provided a solid basis for contributing to a weight-of-evidence assessment of state contributions. In addition, the two CALPUFF platforms can be used to evaluate the relative contributions to fine PM and visibility impacts of individual sources in the MANE-VU region. It is anticipated that MANE-VU will provide all states with a consistent set of modeling results from each of these platforms to serve as a preliminary basis for BART visibility determinations and states will have several options with regard to how these results are used:

- States may accept the MANE-VU modeling as an adequate basis for determining whether BART controls at a facility are justified by its contribution to visibility degradation.
- States may conduct additional modeling on their own to determine whether BART controls at a facility are justified by its contribution to visibility degradation.
- States may require a source to conduct additional modeling to determine whether BART controls at a facility are justified by its contribution to visibility degradation.

These options and the use of modeling results for BART determinations are discussed in more detail in the *MANE-VU BART Resource Book* (NESCAUM, 2006), and the reader is referred to that resource for additional information.

References

NESCAUM, *BART Resource Guide*, Northeast States for Coordinated Air Use Management, 2006.

USEPA, CALPUFF Modeling System, Available at: http://www.epa.gov/ttn/scram, 2006.

8. SYNTHESIS OF RESULTS USING DIFFERENT SOURCE ASSESSMENT TECHNIQUES

By synthesizing results from a variety of data sources and analysis techniques MANE-VU has taken a first step toward identifying sources of visibility impairment in the Northeast generally, and toward understanding the role of transported sulfate in particular. The variety of approach and complexity of analytical tools utilized for this purpose provides numerous metrics and means of comparison into how SO_2 emissions are chemically transformed, transported and combined with various local constituents of fine particle pollution in the MANE-VU region. Beyond reviewing these results, additional sections of this chapter describe opportunities for further synthesizing the available data to solidify a weight-of-evidence approach to implementing the contribution assessment and pollution apportionment requirements of the Haze Rule

8.1. Ranked Contribution

Chapter 4 of this report describes two crude methods of ranking state contributions based on the ratio of source emissions to source-receptor distance as well as the gridded product of emissions and upwind residence time probability. Chapter 5 describes the qualitative evidence available from several different trajectory-based techniques and source apportionment studies. These include source region comparisons, source profile examinations, and the development of other techniques and metrics to support the more quantitative ranking techniques. Chapter 6 describes results obtained using Eulerian grid models such as the Regulatory Modeling System for Aerosols and Deposition (REMSAD) and the Community Multi-scale Air Quality (CMAQ) model. Ultimately these types of models are likely to yield the most definitive assessments of contribution from different sources. Chapter 7 explores the use of lagrangian puff dispersion models such as CALPUFF for estimating source contributions and compares two related but distinct versions of the CALPUFF modeling system that demonstrate the sensitivity of this tool to emissions and meteorology inputs.

In Table 8-1 through Table 8-5 (and graphically in Figure 8-1), we have normalized the results obtained using five techniques for assessing state contribution by calculating the percentage contribution and plotted them on a common graph. The figure shows substantial consistency across a variety of independent analyses using techniques that are themselves based on the application of disparate chemical, meteorological and physical principles. Together, these findings create a strong weight-of-evidence case for identifying the most significant contributors to visibility impairment in MANE-VU Class I areas.

In Figure 8-1, several features of the normalized results bear notice. First, we note that the apparent perfect agreement among the techniques for the “other” contribution that represents all emissions from outside the domain of study is a result of having substituted the REMSAD calculated “other” contribution for all of the other methods. REMSAD is the only method that has a means of developing a comprehensive estimate of the total out-of-domain contribution because the boundary condition used was derived from a global model run using global SO_2 emissions estimates. It is also worth noting how high the “other,” or out-of-domain, contribution is to observed sulfate at

Acadia National Park. This is not surprising given how close Acadia is to the domain boundaries on both the northern and eastern edge. There may be some recirculation of in-domain SO_2 emissions that leave the modeling domain and re-enter through the dynamic boundary condition, but lose their tag in the process.

It is also worth noting the differences between the methods for certain states and Canada, such as Massachusetts and Maine in the case of Acadia, Maryland and Canada for Brigantine, Canada for Lye Brook, and Ohio and West Virginia for Shenandoah. Those states and Canada that are directly upwind a large fraction of the time, either because they are very large geographically or because they are very nearby, are likely to be treated differently by the percent-time-upwind method relative to the other methods. In addition, the CALPUFF models appear to underestimate the contribution from Canada relative to other methods. This is likely to result from an incomplete characterization of the total SO_2 inventory for Canada relative to other methods that are based on the entire MANE-VU Canadian inventory.

Table 8-1. Annual Average Sulfate Impact from REMSAD (%)

RPO	STATE	ACADIA	BRIGANTINE	DOLLY SODS	GREAT GULF	LYE BROOK	MOOSEHORN	SHENANDOAH
CANADA		**8.69**	**7.11**	**3.90**	**14.84**	**12.43**	**7.85**	**4.75**
CENRAP		**0.88**	**1.12**	**1.58**	**1.65**	**1.67**	**0.82**	**1.48**
MANE-VU		**36.17**	**34.83**	**14.81**	**27.83**	**31.78**	**30.08**	**20.59**
MANE-VU	Connecticut	0.76	0.53	0.04	0.48	0.55	0.56	0.08
	Delaware	0.96	3.20	0.30	0.63	0.93	0.71	0.61
	District of Columbia	0.01	0.04	0.01	0.01	0.02	0.01	0.04
	Maine	6.54	0.16	0.01	2.33	0.31	8.01	0.02
	Maryland	2.20	4.98	2.39	1.92	2.66	1.60	4.84
	Massachusetts	10.11	2.73	0.18	3.11	2.45	6.78	0.35
	New Hampshire	2.25	0.60	0.04	3.95	1.68	1.74	0.08
	New Jersey	1.40	4.04	0.27	0.89	1.44	1.03	0.48
	New York	4.74	5.57	1.32	5.68	9.00	3.83	2.03
	Pennsylvania	6.81	12.84	10.23	8.30	11.72	5.53	12.05
	Rhode Island	0.28	0.10	0.01	0.11	0.06	0.19	0.01
	Vermont	0.13	0.06	0.00	0.41	0.95	0.09	0.01
MIDWEST		**11.98**	**18.16**	**30.26**	**20.10**	**21.48**	**10.40**	**26.84**
MIDWEST	Illinois	1.37	1.82	2.56	2.52	2.42	1.30	2.47
	Indiana	2.13	3.29	5.40	3.94	3.93	2.02	5.23
	Michigan	2.02	2.77	3.24	3.88	3.67	1.74	3.20
	Ohio	5.62	9.11	17.98	8.33	9.96	4.62	14.87
	Wisconsin	0.85	1.16	1.08	1.42	1.49	0.72	1.07
VISTAS		**8.49**	**21.99**	**36.75**	**12.04**	**13.65**	**6.69**	**33.86**
VISTAS	Alabama	0.32	1.07	2.13	0.65	0.81	0.25	1.77
	Georgia	0.67	2.32	3.71	1.27	1.31	0.56	3.47
	Kentucky	1.17	2.22	4.89	1.99	2.22	0.98	4.34
	Mississippi	0.01	0.04	0.08	0.03	0.04	0.01	0.07
	North Carolina	1.45	4.19	4.29	1.88	1.89	1.14	4.78
	South Carolina	0.43	1.69	1.04	0.64	0.56	0.36	1.30
	Tennessee	0.61	1.56	3.41	1.11	1.23	0.50	2.73
	Virginia	1.48	4.30	2.82	1.52	1.95	1.13	6.20
	West Virginia	2.35	4.59	14.38	2.96	3.64	1.75	9.19
OTHER		**33.79**	**16.78**	**12.70**	**23.54**	**18.99**	**44.17**	**12.48**
TOTAL ($\mu g/m^3$)		**2.026**	**3.444**	**3.867**	**1.780**	**2.137**	**1.767**	**3.919**

Table 8-2. Annual Average Sulfate Impact from Q/D (%)

RPO	STATE	ACADIA	BRIGANTINE	DOLLY SODS	GREAT GULF	LYE BROOK	MOOSEHORN	SHENANDOAH
CANADA		**11.91**	**6.01**	**0.00**	**8.97**	**12.00**	**18.77**	**6.76**
CENRAP		**1.74**	**1.64**	**1.59**	**2.33**	**1.99**	**1.35**	**1.72**
CENRAP	Arkansas	0.13	0.15	0.13	0.08	0.17	0.09	0.26
	Iowa	0.29	0.19	0.24	0.40	0.32	0.24	0.24
	Louisiana	0.02	0.03	0.02	0.02	0.03	0.02	0.04
	Minnesota	0.22	0.13	0.16	0.30	0.24	0.13	0.19
	Missouri	1.08	1.15	1.03	1.53	1.23	0.87	1.00
MANE-VU		**20.13**	**32.53**	**20.10**	**21.48**	**25.69**	**12.84**	**24.50**
MANE-VU	Connecticut	0.34	0.33	0.11	0.74	0.38	0.21	0.31
	Delaware	0.59	3.01	0.46	0.51	0.67	0.36	1.07
	District of Columbia	0.01	0.05	0.02	0.01	0.02	0.01	0.09
	Maine	1.74	0.15	0.08	0.71	0.15	1.13	0.15
	Maryland	1.83	7.26	3.86	0.43	2.67	1.27	5.27
	Massachusetts	2.89	0.95	0.46	4.61	1.06	1.33	1.22
	New Hampshire	1.07	0.30	0.14	0.42	0.08	0.60	0.18
	New Jersey	0.76	4.22	0.43	3.11	0.75	0.48	1.82
	New York	4.02	4.61	1.93	3.67	6.71	2.83	3.30
	Pennsylvania	6.64	11.57	12.58	6.62	13.07	4.50	11.00
	Rhode Island	0.12	0.05	0.02	0.08	0.04	0.06	0.06
	Vermont	0.10	0.03	0.02	0.57	0.10	0.07	0.04
MIDWEST		**16.99**	**17.48**	**26.30**	**25.38**	**22.84**	**12.49**	**22.46**
MIDWEST	Illinois	2.53	2.16	2.60	3.64	2.98	2.11	2.61
	Indiana	3.94	4.24	5.17	6.01	5.01	2.91	4.50
	Michigan	2.69	1.95	2.46	4.08	3.50	2.16	2.49
	Ohio	6.63	8.34	15.06	9.94	9.98	4.51	11.85
	Wisconsin	1.19	0.79	1.00	1.71	1.38	0.80	1.01
VISTAS		**15.44**	**25.55**	**39.32**	**18.30**	**18.48**	**10.39**	**32.08**
VISTAS	Alabama	1.24	1.69	1.66	1.45	1.60	0.91	1.65
	Georgia	2.36	3.28	3.18	2.62	2.82	1.63	3.30
	Kentucky	2.07	3.36	3.99	3.18	2.79	1.50	3.54
	Mississippi	0.19	0.24	0.22	0.22	0.24	0.14	0.37
	North Carolina	2.27	4.16	9.03	2.59	2.69	1.44	6.60
	South Carolina	1.29	1.62	0.95	1.14	0.94	0.70	1.69
	Tennessee	1.45	2.14	2.49	1.74	1.92	1.06	2.40
	Virginia	1.93	4.36	2.49	1.97	1.78	1.12	4.25
	West Virginia	2.64	4.71	15.33	3.39	3.71	1.88	8.27
OTHER[36]		**33.79**	**16.78**	**12.70**	**23.54**	**18.99**	**44.17**	**12.48**
TOTAL (μg/m^3)		**1.920**	**2.740**	**3.455**	**1.305**	**1.858**	**1.977**	**3.417**

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[36] OTHER is % from REMSAD result; Florida is considered within OTHER

Table 8-3. Annual Average Sulfate Impact from CALPUFF (NWS Observations) (%)

RPO	State	Acadia	Brigantine	Dolly Sods	Great Gulf	Lye Brook	Moosehorn	Shenandoah
CANADA		**8.07**	**2.65**	**2.30**	**7.22**	**5.77**	**9.45**	**2.45**
CENRAP		**2.76**	**2.98**	**3.34**	**5.06**	**4.50**	**2.30**	**3.42**
CENRAP	Iowa	0.93	1.09	1.13	1.65	1.55	0.80	1.17
	Kansas	0.34	0.37	0.41	0.64	0.55	0.28	0.43
	Louisiana	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Minnesota	0.58	0.60	0.62	1.16	0.95	0.49	0.65
	Missouri	0.59	0.59	0.81	1.00	0.91	0.49	0.80
	Nebraska	0.07	0.10	0.11	0.14	0.13	0.06	0.12
	Oklahoma	0.25	0.22	0.26	0.47	0.41	0.20	0.25
MANE-VU		**27.41**	**29.17**	**16.21**	**20.91**	**26.52**	**21.11**	**17.47**
MANE-VU	Connecticut	0.58	0.50	0.03	0.26	0.27	0.41	0.06
	Delaware	0.48	1.90	0.21	0.31	0.32	0.38	0.44
	District of Columbia	0.02	0.07	0.02	0.03	0.02	0.02	0.05
	Maine	2.40	0.12	0.01	0.53	0.18	2.04	0.02
	Maryland	1.90	5.22	2.54	2.19	2.47	1.55	4.01
	Massachusetts	5.73	1.58	0.12	1.44	1.29	4.13	0.19
	New Hampshire	2.02	0.26	0.02	0.79	0.47	1.36	0.04
	New Jersey	0.98	3.37	0.28	0.63	0.67	0.75	0.52
	New York	5.06	4.92	1.24	4.67	7.20	4.03	1.63
	Pennsylvania	7.19	10.97	11.71	8.86	11.16	5.65	10.48
	Rhode Island	0.31	0.14	0.01	0.08	0.06	0.22	0.01
	Vermont	0.73	0.12	0.01	1.13	2.41	0.56	0.02
MIDWEST		**16.85**	**19.99**	**33.09**	**26.68**	**26.98**	**14.21**	**29.46**
MIDWEST	Illinois	2.12	2.37	2.86	3.36	3.11	1.84	2.74
	Indiana	3.67	4.28	6.52	5.83	5.57	3.19	6.11
	Michigan	3.06	2.25	3.28	4.74	4.74	2.67	2.97
	Ohio	6.31	9.07	18.33	9.82	10.66	5.07	15.55
	Wisconsin	1.69	2.03	2.10	2.93	2.90	1.44	2.09
VISTAS		**11.12**	**28.43**	**32.35**	**16.59**	**17.24**	**8.76**	**34.72**
VISTAS	Alabama	0.43	1.26	1.77	0.77	0.85	0.32	1.96
	Georgia	0.65	2.13	2.12	1.30	1.41	0.52	3.06
	Kentucky	2.05	3.23	5.29	3.39	3.59	1.64	4.59
	Mississippi	0.01	0.03	0.04	0.03	0.03	0.01	0.04
	North Carolina	1.84	6.03	3.20	2.52	2.51	1.42	6.18
	South Carolina	0.61	1.87	0.75	0.80	0.71	0.49	1.33
	Tennessee	1.10	2.19	3.27	1.72	1.80	0.86	3.33
	Virginia	1.72	6.33	2.42	1.80	1.86	1.32	4.85
	West Virginia	2.71	5.37	13.49	4.26	4.48	2.17	9.39
OTHER[36]		**33.79**	**16.78**	**12.70**	**23.54**	**18.99**	**44.17**	**12.48**
TOTAL ($\mu g/m^3$)		**1.571**	**2.533**	**3.125**	**1.167**	**1.701**	**1.429**	**2.793**

Table 8-4. Annual Average Sulfate Impact from CALPUFF (MM5) (%)

RPO	STATE	ACADIA	BRIGANTINE	DOLLY SODS	GREAT GULF	LYE BROOK	MOOSEHORN	SHENANDOAH
CANADA		**8.05**	**2.65**			**5.76**		**2.46**
CENRAP		**3.26**	**2.85**			**5.08**		**2.74**
CENRAP	Arkansas	0.23	0.32			0.39		0.33
	Iowa	0.82	0.75			1.28		0.74
	Kansas	0.43	0.29			0.65		0.24
	Louisiana							
	Minnesota	0.41	0.39			0.71		0.37
	Missouri	1.01	0.80			1.48		0.74
	Nebraska	0.10	0.08			0.15		0.07
	Oklahoma	0.25	0.23			0.42		0.24
	Texas	0.00	0.00			0.00		0.00
MANE-VU		**28.09**	**31.83**			**27.69**		**19.31**
MANE-VU	Connecticut	0.43	0.27			0.25		0.04
	Delaware	0.01	0.07			0.02		0.03
	District of Columbia	0.60	2.81			0.73		0.57
	Maine	1.62	0.06			0.14		0.01
	Maryland	1.68	5.95			2.59		4.27
	Massachusetts	8.67	1.87			2.18		0.23
	New Hampshire	2.05	0.26			0.56		0.04
	New Jersey	0.97	3.60			0.91		0.49
	New York	4.41	4.30			8.08		1.79
	Pennsylvania	7.44	12.57			11.86		11.83
	Rhode Island	0.14	0.04			0.04		0.00
	Vermont	0.08	0.02			0.33		0.00
MIDWEST		**16.28**	**21.79**			**25.58**		**28.43**
MIDWEST	Illinois	1.89	1.78			2.68		1.85
	Indiana	3.57	4.46			5.48		5.22
	Michigan	2.30	2.41			3.47		2.53
	Ohio	7.53	12.11			12.30		17.88
	Wisconsin	0.98	1.04			1.65		0.95
VISTAS		**10.53**	**24.10**			**16.90**		**34.57**
VISTAS	Alabama	0.43	0.79			0.79		1.32
	Georgia	0.78	1.74			1.30		2.50
	Kentucky	2.02	3.47			3.22		4.73
	Mississippi	0.01	0.03			0.04		0.04
	North Carolina	1.72	4.23			2.53		5.74
	South Carolina	0.50	1.10			0.62		0.84
	Tennessee	1.07	2.04			1.82		3.07
	Virginia	1.36	4.70			1.99		4.32
	West Virginia	2.64	6.00			4.58		12.03
OTHER[36]		**33.79**	**16.78**	**12.70**	**23.54**	**18.99**	**44.17**	**12.48**
TOTAL (μg/m^3)		**2.424**	**3.589**			**2.430**		**3.761**

Table 8-5. Annual Average Sulfate Impact from percent time upwind method (%)

RPO	STATE	ACADIA	BRIGANTINE	DOLLY SODS	GREAT GULF	LYE BROOK	MOOSEHORN	SHENANDOAH
CENRAP	Arkansas	0.12	0.24		0.15	0.15	0.15	0.20
	Iowa	0.38	0.27		0.27	0.28	0.28	0.25
	Kansas	0.00	0.00		0.00	0.00	0.00	0.00
	Louisiana	0.04	0.08		0.06	0.04	0.04	0.09
	Minnesota	0.56	0.33		0.38	0.44	0.44	0.22
	Missouri	0.80	0.85		0.87	0.75	0.62	0.95
	Texas	0.00	0.00		0.00	0.00	0.00	0.00
MANE-VU	Connecticut	0.51	0.27		0.52	0.59	0.40	0.10
	Delaware	0.30	1.36		0.34	0.42	0.28	0.24
	District of Columbia	0.12	0.29		0.11	0.14	0.12	0.24
	Maine	1.49	0.08		0.68	0.26	1.53	0.05
	Maryland	1.32	3.06		1.31	1.31	0.96	2.29
	Massachusetts	1.10	0.33		0.86	0.81	0.90	0.12
	New Hampshire	1.21	0.17		1.48	0.72	0.77	0.06
	New Jersey	1.02	6.01		0.99	1.39	0.78	0.49
	New York	4.80	3.49		6.80	9.08	4.23	1.44
	Pennsylvania	6.21	10.71		7.10	10.36	5.07	6.33
	Rhode Island	0.11	0.05		0.08	0.08	0.09	0.02
	Vermont	0.14	0.03		0.37	0.23	0.10	0.01
MIDWEST	Illinois	3.79	3.47		3.31	3.74	3.22	3.76
	Indiana	3.37	4.36		4.33	4.13	3.21	5.08
	Michigan	2.73	2.07		3.03	3.27	2.34	1.80
	Ohio	6.10	8.65		8.73	9.23	5.77	10.64
	Wisconsin	1.36	1.00		1.28	1.25	1.02	0.76
					14.14	**16.43**	**10.07**	**48.06**
VISTAS	Alabama	0.72	1.32		0.63	0.71	0.39	2.14
	Georgia	1.40	3.21		1.06	1.54	0.72	4.73
	Kentucky	2.65	4.71		3.59	3.83	2.31	7.82
	Mississippi	0.04	0.10		0.06	0.06	0.03	0.12
	North Carolina	1.29	4.35		0.92	0.99	1.18	6.11
	South Carolina	0.72	1.64		0.42	0.41	0.44	1.62
	Tennessee	1.05	1.91		1.04	1.16	0.86	3.67
	Virginia	1.80	4.83		1.48	1.67	1.32	5.45
	West Virginia	3.74	7.31		4.94	6.05	2.81	16.39
OTHER[36]		**33.79**	**16.78**	**12.70**	**23.54**	**18.99**	**44.17**	**12.48**

MANE-VU will continue to explore these differences, but it remains encouraging that the use of different platforms and approaches results in more agreement across the various techniques than difference. With the few, specific exceptions mentioned above, it is relatively easy — using the normalized results from multiple techniques shown in Figure 8-1(a-d) — to identify those states that have the largest influence on sulfate levels at each Class I site. MANE-VU believes that this information can provide a solid basis for initiating consultation and planning efforts between upwind and downwind states and RPOs.

Figure 8-1(a-d). Comparison of normalized (percent contribution) results using different techniques for ranking state contributions to sulfate levels at the MANE-VU Class I sites (a) Acadia National Park, ME, (b) Brigantine Wilderness Area, NJ, (c)Lye Brook Wilderness Area, VT, and (d) Shenandoah National Park, VA.

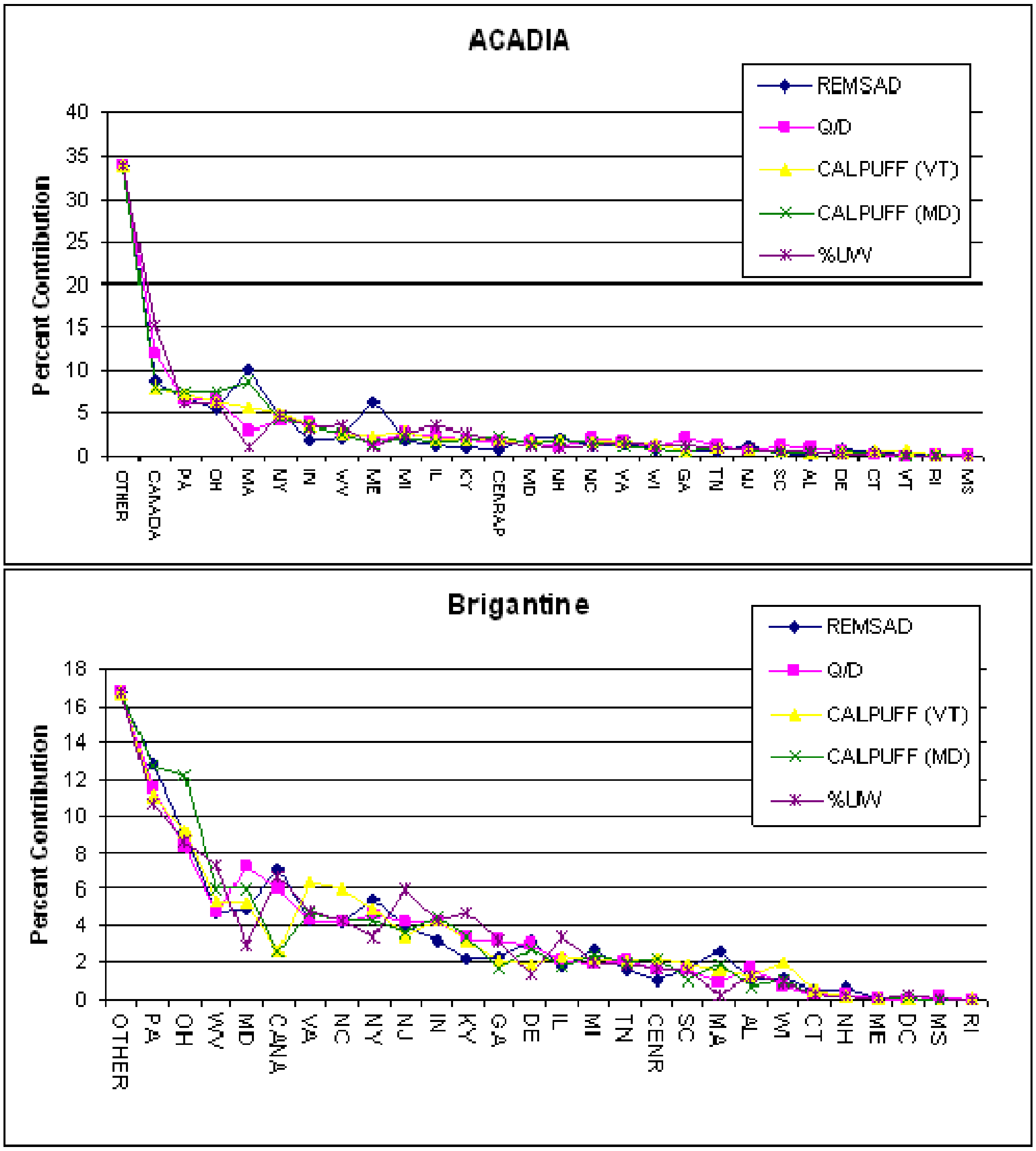
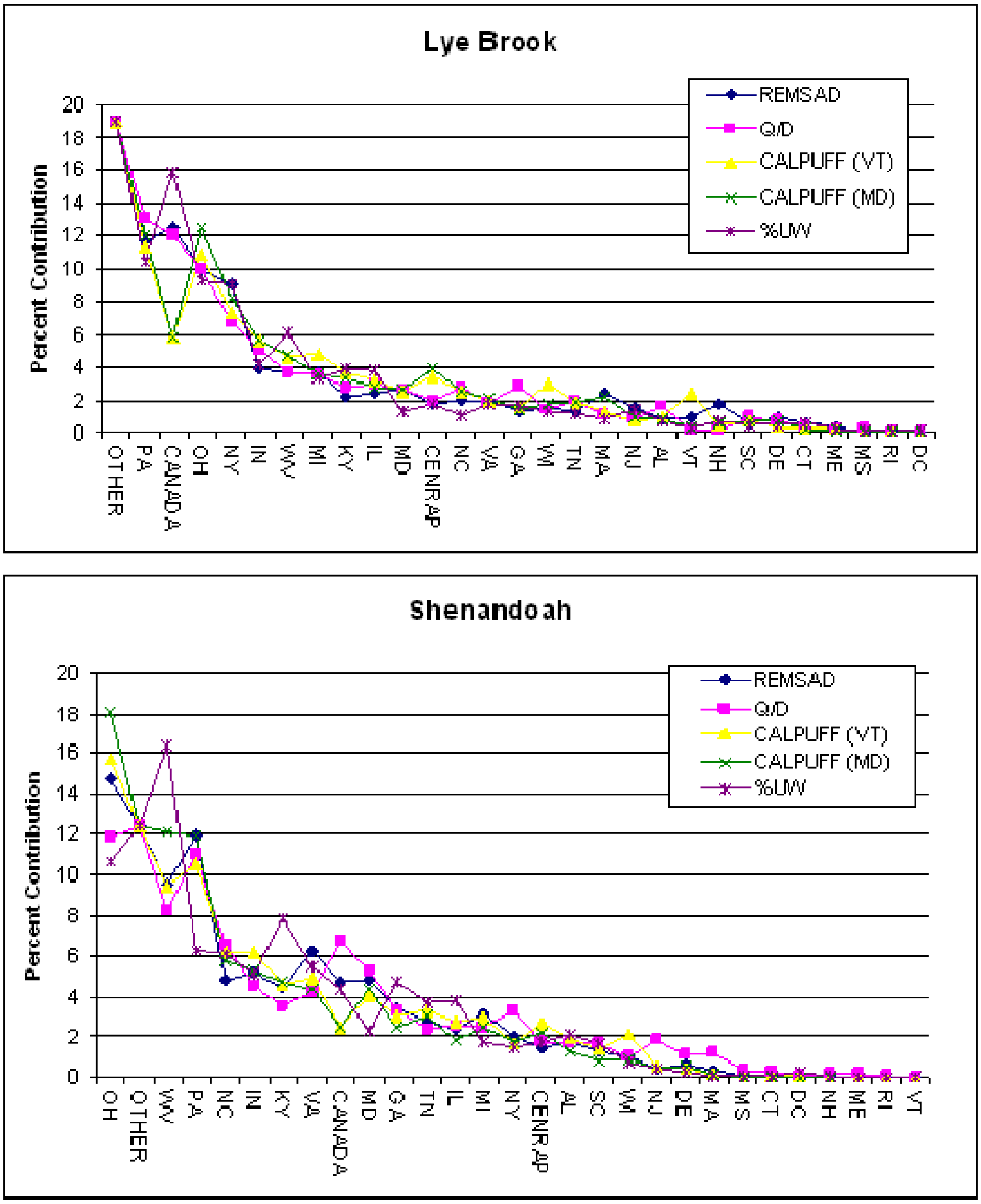


Figure 8-1(a-d). Continued



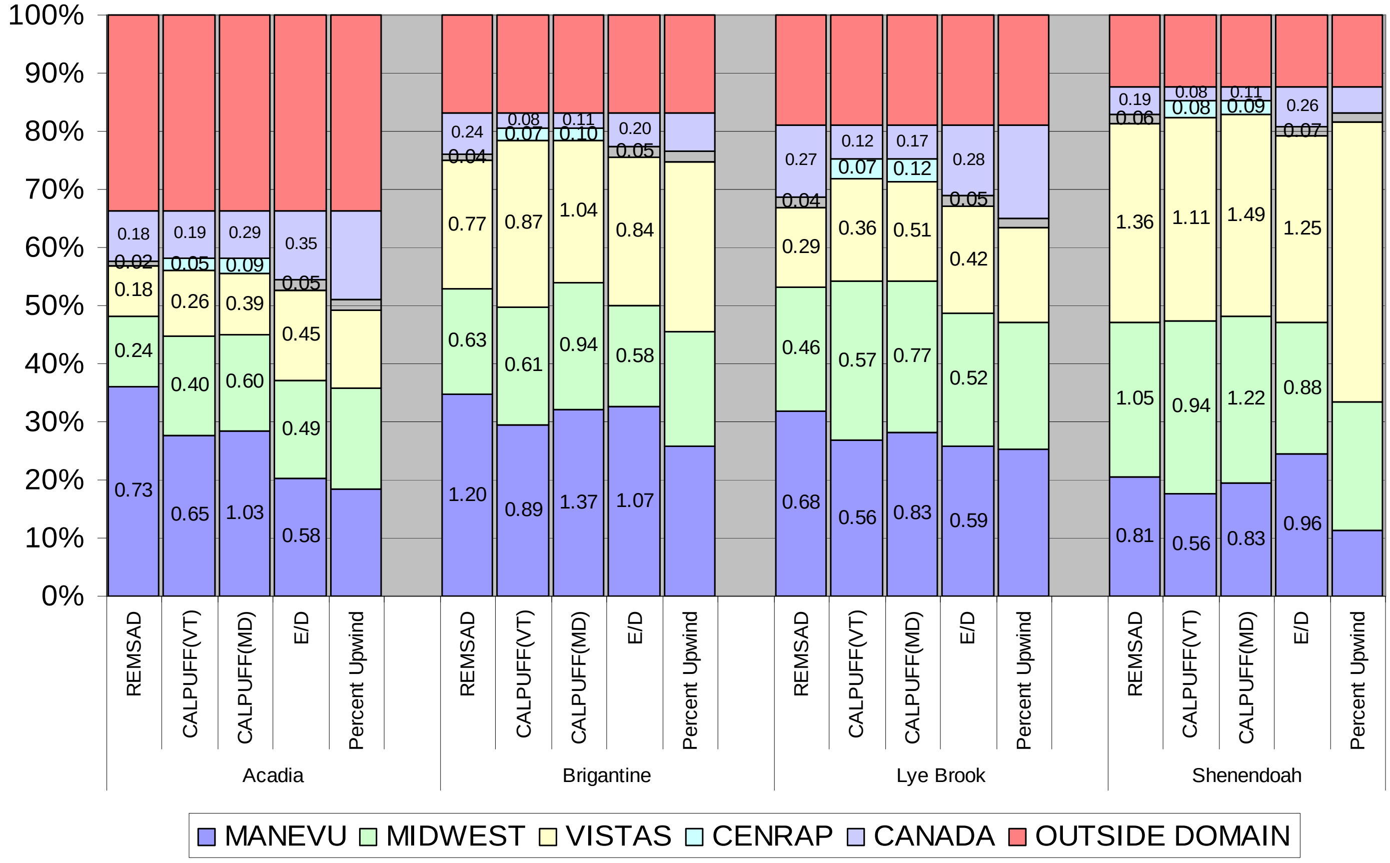
An alternative means of displaying the above results is in Table 8-6, which shows the individual state rankings produced by different assessment techniques for Acadia National Park, Maine. In the left-side column of Table 8-6, states are colored according to their average ranking across the different assessment methods. Those states that are ranked in the top five on average, across all techniques are colored red, while states ranked in the top six through ten are colored magenta, and so on for each group of five going down the left-side column. Through this color scheme, one can see how the states' average ranking compares to their rankings under each individual assessment method given in the other columns of the table. The fact that all techniques tend to come to consistent conclusions about which states are top contributors provides some confidence that the source regions with the most influence on sulfate levels at MANE-VU Class I sites can be correctly identified. Note that the CENRAP states and several other states along the border of the analysis domain represent only partial state contributions.

Table 8-6. Ranked Contributing States to Acadia Sulfate

Average	REMSAD	Q/d	CALPUFF (VT)	CALPUFF (MD)	E x RTP
CANADA	MA	CANADA	CANADA	MA	CANADA
PA	CANADA	PA	PA	CANADA	PA
OH	PA	OH	OH	OH	OH
MA	ME	NY	MA	PA	NY
NY	OH	IN	NY	NY	IL
IN	NY	MA	IN	IN	WV
WV	WV	MI	MI	WV	IN
ME	NH	WV	WV	CENRAP	MI
MI	MD	IL	ME	MI	KY
IL	IN	GA	IL	NH	CENRAP
KY	MI	NC	CENRAP	KY	VA
CENRAP	VA	KY	KY	IL	ME
MD	NC	VA	NH	NC	GA
NH	NJ	MD	MD	MD	WI
NC	IL	CENRAP	NC	ME	MD
VA	KY	ME	VA	VA	NC
WI	DE	TN	WI	TN	NH
GA	CENRAP	SC	TN	WI	MA
TN	WI	AL	NJ	NJ	TN
NJ	CT	WI	VT	GA	NJ
SC	GA	NH	GA	DE	AL
AL	TN	NJ	SC	SC	SC
DE	SC	DE	CT	AL	CT
CT	AL	CT	DE	CT	DE
VT	RI	MS	AL	RI	VT
RI	VT	RI	RI	VT	DC
MS	MS	VT	DC	DC	RI
DC	DC	DC	MS	MS	MS

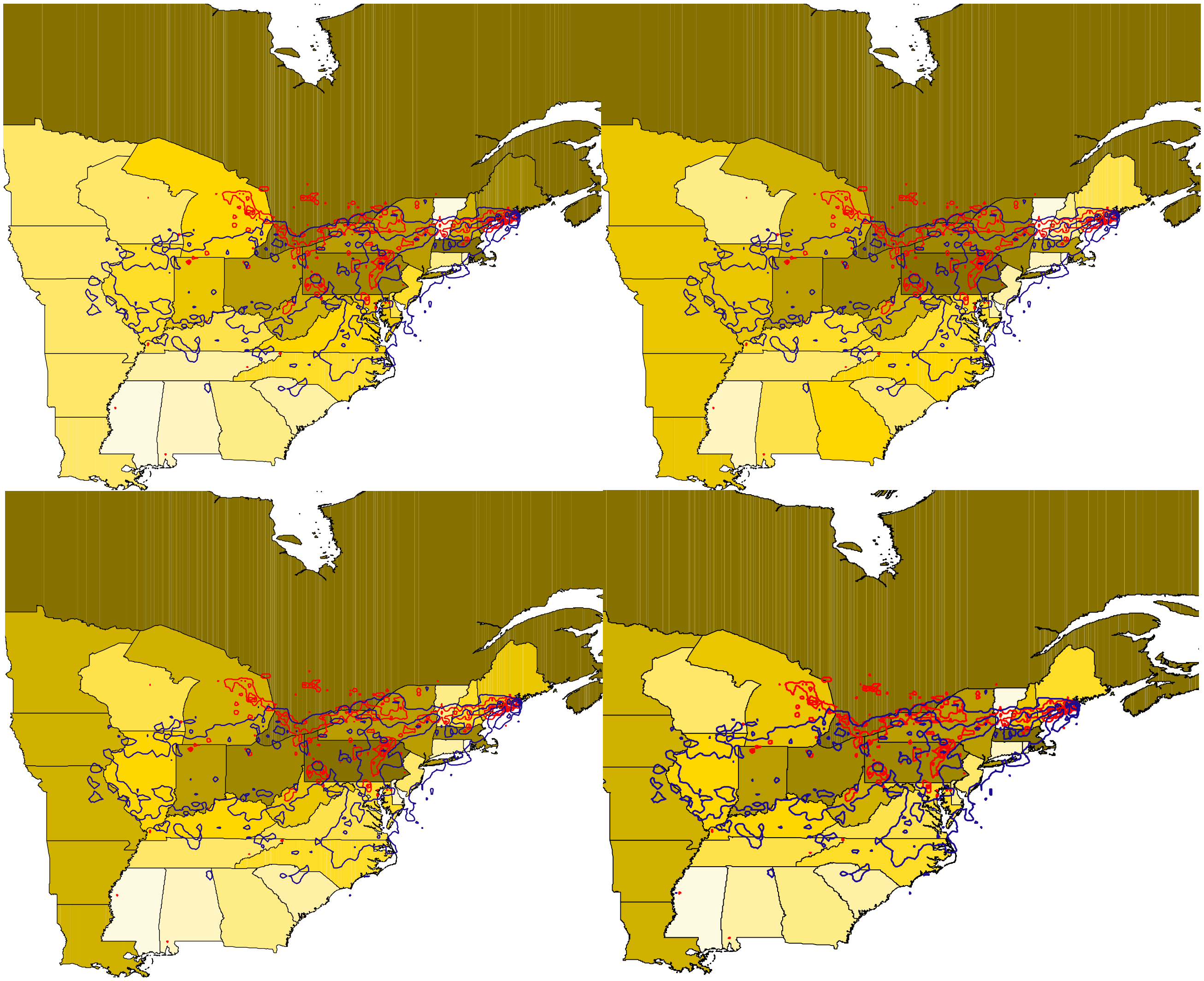
Yet one more way of combining the ranked contributions is shown in Figure 8-2, which summarizes the relative contributions of four RPOs, Canada, and “outside domain” regions to ambient sulfate concentrations at several Class I areas using four different assessment techniques. The techniques considered here include: tagged REMSAD modeling, two CALPUFF platforms (MM5-based meteorology used by MDE and NWS observation-based meteorology used by VT DEC), the empirical emissions divided by distance approach (Q/d), and emissions times residence time probability. The estimates of state-by-state sulfate mass contributions ($\mu g/m^3$) from each method have been aggregated by RPO, both in terms of their absolute contribution (these values are displayed within the bars shown in the graphic) and in terms of their proportional contribution relative to other RPOs. It should be noted that the “outside domain” contribution shown for each analysis method was derived exclusively from the REMSAD result. Averaging estimated impacts at the Acadia, Brigantine, and Lye Brook sites over the four assessment techniques utilized, MANE-VU states account for about 20 to 30 percent of sulfate impacts in these three MANE-VU Class I areas, while the Midwest RPO and VISTAS states each account for about 20 to 25 percent of the total sulfate contribution at Brigantine and Lye Brook and about 10 to 15 percent each at Acadia. The CENRAP states, Canada and "outside domain" add the remainder. Although variation exists across estimates of contribution for different sites and using different techniques, the overall pattern is generally consistent. Relative contributions are somewhat reversed at Shenandoah, which is a VISTAS Class I area. There, VISTAS states and Midwest RPO states account for roughly 20 to 30 percent of overall sulfate impacts, with MANE-VU states contributing roughly 15 to 20 percent.

Figure 8-2. Estimated RPO contributions to sulfate concentrations at Class I areas using different assessment techniques



While the foregoing discussion has focused on quantitative methods for comparing contributions from individual states and regions, additional analyses have been conducted to verify and support these results using more qualitative means of identifying "regions of influence" for each Class I area. One such qualitative approach to synthesizing and interpreting the results obtained through different assessment techniques is illustrated in Figure 8-3 and Figure 8-4 below, which show a series of maps shaded to indicate different levels of contribution from different states and regions as determined by the analysis platforms already discussed. In these maps, states are shaded darker the higher they rank in terms of percent contribution to sulfate at a Class I site. For example, in Figure 8-3, states in a line from Indiana through Massachusetts are calculated to have the greatest impact on sulfate at Acadia. Overlaid on top of these maps are contours of

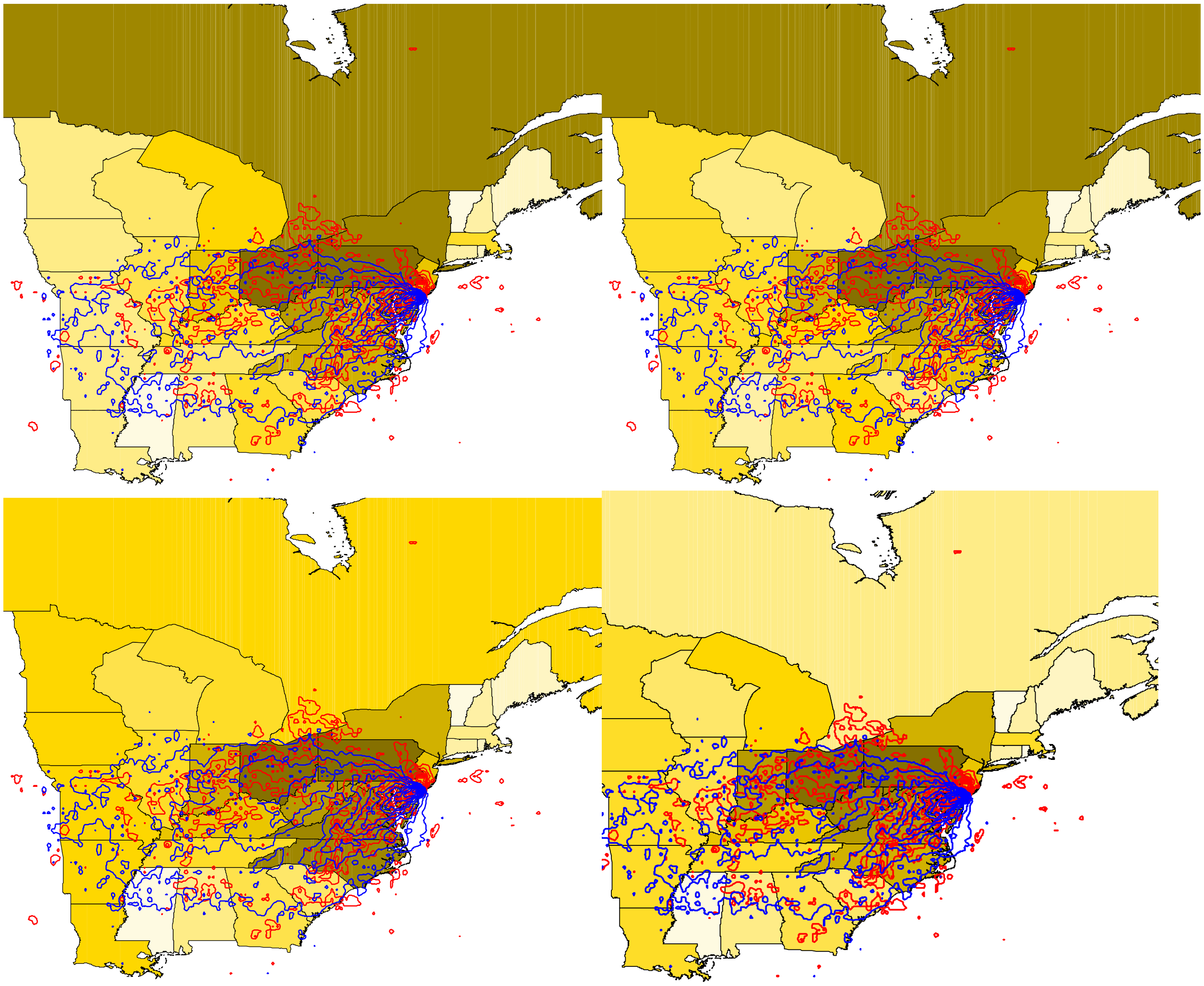
Figure 8-3. Ranked contributions of states to ambient sulfate concentrations at Acadia National Park, Maine.



Note: Shaded maps show contributions as estimated by REMSAD, Emissions divided by Distance, CALPUFF VT, and CALPUFF MD. Red and blue contours representing regions of high incremental probability (IP) and high cluster-weighted probability (CWP) are overlaid onto the shaded state maps to indicate similarity of regional contributions as calculated by these independent receptor-based methods.

Incremental Probability (red) and Cluster Weighted Probability (blue) of contributing to sulfate on the highest days. The substantial consistency in the patterns support and bolster the quantitative results. The importance of this finding is that the receptor-based results portrayed by the contours rely on methods that are completely independent of the source-based modeling approaches used to calculate the underlying ranks. This sort of internal consistency among approaches gives considerable strength to the weight-of-evidence approach that MANE-VU has adopted for identifying sulfate source regions.

Figure 8-4. Ranked contributions of states to ambient sulfate concentrations at Brigantine Wilderness Area, New Jersey.



Note: Shaded maps show contributions as estimated by REMSAD, Emissions divided by Distance, CALPUFF VT, and CALPUFF MD. Red and blue contours representing regions of high incremental probability (IP) and high cluster-weighted probability (CWP) are overlaid onto the shaded state maps to indicate similarity of regional contributions as calculated by these independent receptor-based methods.

9. CONCLUSION

As MANE-VU prepares to implement the requirements of the Regional Haze Rule, a significant technical effort has focused on developing multiple analysis tools for assessing contributions to fine particle pollution and thus visibility impairment at Class I areas in the eastern United States. These analysis tools span the discipline of atmospheric science and include traditional Eulerian “source” or “grid” models, Lagrangian dispersion models, back trajectory receptor techniques, source apportionment models, and simple approximations based on empirical relationships between emissions and geography.

A review of the literature and of recent monitoring data has yielded a conceptual model of visibility impairment in the MANE-VU region that attributes a dominant role, on the worst visibility days, to the sulfate component of fine particle matter. This model in turn suggests that the most effective near-term strategy for reducing fine particle pollution and visibility impairment in the East is to continue reducing anthropogenic emissions of SO_2. Reductions in both NO_X and VOCs should also be considered. Given that sulfate, in particular, plays a dominant role in causing visibility impairment throughout the East, MANE-VU has focused on multiple methods of apportioning the sulfate mass found in ambient air at Class I sites to contributing states and regions. This weight-of-evidence approach is intended to overcome large uncertainties that would otherwise undermine confidence in the results obtained using any one modeling or analysis technique in isolation.

The assessment techniques described in this report use numerous approaches to develop ranked lists of individual state contributions to sulfate levels in MANE-VU Class I areas. When these results are normalized and compared, we find broad general agreement concerning the top contributing states at each site as well as some differences that suggest the magnitude of uncertainty inherent in these results.

The conclusions that emerge from this report regarding the relative contributions of different upwind RPOs to downwind sulfate concentrations at MANE-VU Class I areas appear quite robust and the modest differences presented here relative to the preliminary results presented in Spring of 2005 are a further indication that the general patterns of contribution presented here are unlikely to change due to further refinements of the emissions and meteorological inputs. This suggests that the MANE-VU findings are sufficiently robust to serve as a basis for inter-RPO consultations and the regional haze planning process. Given that as much as 30 to 50 percent of the ambient sulfate found at northeastern Class I sites on hazy days appears to originate within neighboring RPOs, coordination and consultation is likely to be critical if MANE-VU is to achieve its visibility goals for 2018 and beyond.

Appendix A: Application of Trajectory Analysis Methods to Sulfate Source Attribution Studies in the Northeast U.S.

Appendix B: Source Attribution by Receptor-Based Methods

Appendix C: Chemical Transport Model Results for Sulfate Source Attribution Studies in the Northeast U.S.

Appendix D: Development of Parallel CALPUFF Dispersion Modeling Platforms for Sulfate Source Attribution Studies in the Northeast U.S.

Appendix B

Summary of Federal Land Manager Comments and Responses

U.S. Fish and Wildlife Service and National Park Service Comments

New York Draft Regional Haze Rule State Implementation Plan

May 18, 2009

The State of New York (NY) submitted a draft Regional Haze Rule State implementation plan (SlP), pursuant to the requirements codified in federal rule at 40 CFR 51.308(i)(2), that the U.S. Department of the Interior, U.S. Fish and Wildlife Service (FWS) received on February 17, 2009. The FWS and National Park Service Air Quality (NPS) staff participated in a conference call on March 17, 2009, with NY Department of Environmental Conservation (NYDEC) staff to discuss concerns with the draft document. Subsequently, NY decided that the FWS and NPS concerns would be considered and another draft document would be sent to FWS and NPS at a future date. We received the revised draft on April 22, 2009, and the comments below reflect our review of this most recent draft SIP.

We encourage a continued dialog between our offices, and we are willing to work with the NYDEC staff toward resolving the issues discussed below. For further information, please contact Tim Allen, FWS Regional Haze lead at (303) 914-3802.

Overall Comments

1. Comment: We commend NYDEC for the hard work required to write the draft SIP and the staffs willingness to discuss and consider our comments on the initial draft. However, at this

time, most of our concerns remain.

Response: Comment acknowledged.

2. Comment: One of our most significant concerns is that the Best Available Retrofit Technology (BART) requirements for this Regional Haze Plan have not been met. It is our understanding that this is due in part to the lack of the State's adoption of a BART Rule that will contain the requirements for BART controls. The NY BART rule will provide affected source owners with the opportunity to conduct "exemption modeling," breaking from the non-exemption agreement made by all Mid-Atlantic Northeastern Visibility Union (MANE-VU) States. This opportunity for the affected sources has not yet been formally extended because the absent NY BART Rule is not expected to become effective until February 2010. Therefore, it is unclear which sources will be required to perform a BART determination in the State. Additionally, the threshold by which a source may be shown to cause or contribute to visibility impairment in Class I areas affected by NY will also be contained in the upcoming NY BART Rule, thus this required information is also missing from this draft SIP. The NY draft SIP acknowledges that each source subject to BART will not be required to submit a plan detailing how it will comply with the BART requirements until mid to late 2010. Nonetheless, the approval requirements in the Environmental Protection Agency (EPA) BART Guidelines make it clear that a SIP must include not only commitments, but descriptions as to how the commitments will be implemented, both of which the NY draft SIP lacks. The EPA has many times voiced its concern and objections about States that choose to submit commitment-based SIPs. Therefore, it

is our opinion that without a complete BART analysis and determination evaluation, the SIP fails to meet one of the basic requirements intended for Regional Haze SIPs, and therefore, the NY Regional Haze SIP may not be approvable in its current form.

<u>Response:</u> New York must have an adopted rule in place to apply BART requirements. Promulgation of this rule is in process.

3. <u>Comment:</u> Additionally, the State does not provide sufficient summary or support showing that controls will account for NY's "share" of impact at affected Class I areas. The State may use information provided by the MANE-VU. However, the information provided by MANE-VU is to be used to help form information that is specific to New York, including State specific visibility apportionment. A comparison of visibility before and after NY's emission reduction efforts is imperative toward demonstrating the effectiveness of NY's SIP.

<u>Response:</u> Revisions have been incorporated throughout the SIP to address this comment and clarify the state-specific application of the information in this SIP. State-specific visibility apportionment information is not required or necessary, was not developed during the technical work conducted while this SIP was being prepared, and will not be available.

4. <u>Comment:</u> Specifically regarding Reasonable Progress evaluation and Long Term Strategies, although NY does not have any Class I areas within its boundary, it must still conduct, summarize, and conclude that controls meet the level of "reasonable." Documents

provided from MANE-VU can support this effort. However, NYDEC should provide its technical evaluation and description of its decision-making rationale. Please provide additional information explaining control level selections and the reasoning of how NYDEC supports the conclusion of reasonable control. Please relate and support the State's conclusions by using the four factors identified in the statute and rule.

Response: New York participated in consultations with the Class I states and other members of MANE-VU, and it was determined during the consultation process that the proposed levels of controls were reasonable on both a regional and state-specific basis. The means by which this determination was made is described in detail in the SIP and in Appendix J, "*Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*," Final, July 9, 2007, otherwise known as the Reasonable Progress Report. New York has committed to implementing these controls both in its participation in the regional SIP process and through direct statements in the SIP itself.

5. Comment: Furthermore, NYDEC does not specifically identify the inconsistencies of using MANE-VU based Reasonable Progress Goal calculations. These final runs are based on Clean Air Interstate Rule (CAIR), MANE·VU "asks," and emission redistribution control assumptions. These controls are presently not realized, nor are the control commitments from other States' implementation plans which NYDEC is depending upon to accomplish reductions in the NY SIP. Therefore, more information should supplement the document that fully describes the uncertainty and whether the State or MANE-VU has any efforts planned (or in

progress) to minimize these uncertainties. Specifically addressing these future estimates with more specific projections in the State's year 2013 midterm review is important.

Response: The SIP is based on cooperative planning among the MANE-VU states. Each state must implement emission reductions that will enable the achievement of the Reasonable Progress Goals in the appropriate years. New York has no control over the other states. If controls that are required to be implemented have not been put in place and therefore, the Reasonable Progress Goals are not achieved, EPA will need to deal with the states that are involved. SIPs are not required to contain failure analyses and so this is not included in New York's document. Uncertainties related to the CAIR program can only be dealt with when the replacement program is promulgated. At this time, states are forced to assume that emission reductions under the replacement program will be equal to those assumed under the adopted and implemented CAIR rules.

6. Comment: The regional haze rule has specific requirements including that the SIP demonstrate how controls meet BART and reasonable progress.

Response: Comment acknowledged.

7. Comment: Finally, the modeling discussion does not provide sufficient detail to allow the reader to understand the strengths and limitations of the modeling exercise and how it specifically applies to NY. For example; the modeling discussion should provide a narrative

summarizing the State's description and performance evaluation of all models used, as well as a narrative that presents performance assurances for both regional and State levels including whether model projections were used in a relative or absolute manner. It is not enough to merely reference the Appendix containing the MANE-VU modeling report.

Response: The type of detail requested here belongs in an Appendix and, indeed, appears in Appendix R - "MANE-VU Modeling for Reasonable Progress Goals Model performance evaluation, pollution apportionment, and control measure benefits." However, additional detail has been added to the SIP document briefly discussing model performance.

Document Specific Comments

The remaining comments below are intended to provide specific suggestions on sections of the report which include some of the issues raised above. These comments are consistent with the priorities that we presented in our August 1, 2006, letter to the States (enclosed) that we reference in our cover letter. Our hope is that these specific comments will be helpful to NYDEC toward providing direction for building the narrative of the NY Draft SIP to satisfy the content areas mentioned above where we believe deficiencies exist.

1.0 Background and Overview of the Federal Regional Haze Regulation

8. Comment: Section 1.3, page 1-3 - We initially commented that a 2 percent contribution

of sulfate was deemed by MANE-VU as an appropriate "area of influence" for visibility impacts on Class 1 areas. We asked that NYDEC summarize in more detail the method used to make this determination. We went on to say that the State should communicate in this section why they think this method is appropriate. The discussion NYDEC provided in its April 22, 2009, reply to our initial comments will suffice. Please include it in the final SIP. That text is copied here for reference:

> "MANE-VU prepared a contribution assessment document in order to identify states where emissions are most likely to influence visibility in MANE-VU Class 1 areas. Based on this analysis, MANE-VU concluded that it was appropriate to define an area of influence including all of the states participating in MANE-VU plus other states that modeling indicated contributed at least 2% of the sulfate ion at MANE-VU Class I areas in 2002. The 2% was arrived at after a review of the back trajectory and modeling results showing that states contributing 2% (or more) make up about 90-95% "of total light extinction. For states contributing 5% (or more), only about 75-80% of total light extinction is accounted for. New York agrees with the 2% criteria, given the high percentage of light extinction for which it accounts. New York believes that the 2% criteria represents a level of contribution for visibility impairment from any state that needs to be assessed for mitigation. Failure to do so will result in Class I areas failing to reach their reasonable progress goals and ultimately delay needed improvements in air quality."

Response: This language has been included in the SIP in Section 1.3.

9. Comment: Finally, we are asking again that NYDEC indicate what effect this status has on the SIP.

Response: The discussion under Comment 8 above has no "status." However, New York agreed with MANE-VU's assessment and decision to use the 2% rule based on visibility improvement. With the cutoff level of 2%, about 90-95% "of total light extinction emissions are accounted for. Using a lower cutoff would provide little return, especially given the accuracy of inventories and models in general which are not usually 100%. Thus, the visibility impacts presented in the SIP are the most accurate that could be expected given the methods and data available.

10. Comment: Section 2.1, page 2-1 - Several paragraphs offer reasons why the SIP was not provided to EPA by the statute-mandated date of December 17, 2007. These paragraphs mislead the reader into thinking that the State had no role or responsibility in the late completion of the NY SIP. In all fairness, NYDEC should communicate in the SIP that the due date of December 17, 2007, was clearly established in the Regional Haze Rule in June 1999, and all States, Regional Planning Organizations (RPOs) and FLMs have been aware of this deadline for some time.

Response: The language in the SIP provides sufficient and appropriate discussion on the status of the SIP.

11. Comment: Figures 7-1, 7-4, 7-6, 7-7, and 7-10, pages 7-10, 7-14, 7-17, and 7-20 - These figures provide pre-baseline, State specific, and emission levels of several pollutants. In our initial comments, we pointed out that the value of how these figures supported the conclusions of the NY SIP was unclear. We went on to say that regional haze baseline emissions in the draft NY SIP are defined as 2000-2004 and 2002 for monitoring and emissions, respectively. Additionally, tables also are labeled as V2 2002 emissions where the State identifies version 3 as the emission database used. We asked that NYDEC communicate how these figures contributed to the conclusions of the SIP. In response to our comments the State replied that:

> "These figures show SO2, NOx, PM10, PM2.S and ammonia emissions trends in the MANE-VU states extracted from the NEI for the years 1996, 1999, and the 2002 MANE-VU inventory. Comparing emissions from each year, these figures provide an indication of whether there is an identifiable trend in emissions prior to the base year, as well as to provide the ability to show the relative emissions on a state-specific basis for these three years. The reader is thus able compare the relative emissions from each state as well as to assess whether a trend in emissions is evident over this period. This information is useful in determining what air program-related changes might have been effective in influencing the levels of these pollutants in recent years, and is suggestive of what trends might be seen in the first planning period. For example, the discussion of these figures

> related to SO2 suggests that most states show declines in year 2002 as compared to 1996 emissions. Where it occurred, the upward trend in emissions after 1996 likely reflects electricity demand growth during the late 1990s combined with the availability of banked emissions allowances from initial overcompliance with control requirements in Phase 1 of the EPA Acid Rain Program. Understanding the material presented in these graphs is useful in determining how to project emissions and judging whether projections are reasonable. The interpretation of each graph is discussed in detail in the adjacent portions of section 7."

This language is very useful in helping the reader to understand what information NYDEC intends these graphs to communicate. Please include it in this section of the SIP.

Response: This language was inserted in the SIP as new section 7.5.6.

12. Comment: Section 7.6 - NYDEC did an excellent job identifying and discussing how the State's emissions compare with that of MANE-VU's, and the section provides the reader with helpful information.

Response: Comment acknowledged.

8.0 Best Available Retrofit Technology (BART) Requirements

13. Comment: Section 8.4, page 8-6 - In the last paragraph of the page, NYDEC indicates that only after rulemaking is complete (in 2010), will a final list of BART-eligible facilities be identified. This statement and subsequent wording in section 8.5 imply that work toward evaluating BART determinations has not begun. Please explain why the BART process cannot or has not begun as of the submittal of this draft SIP to the FLMs. Our experience from working with other States and RPOs is that BART analysis often begins and proceeds prior to the finalization of BART rulemaking.

Response: New York cannot presume the result of any rulemaking until a state rule is in place. This includes compelling BART-eligible sources to conduct a BART analysis. There is no way to circumvent this under state law. A preliminary analysis has been done by NESCAUM. This analysis says in New York State less than 20 sources are BART-eligible. Until rulemaking is completed, final determinations cannot be made.

14. Comment: As we mentioned above, the Regional Haze SIP as submitted does not contain any BART determinations for sources that have heretofore been identified as likely BART candidates. Kodak Park Division, a chemical manufacturer, and Lafarge Building Materials, lnc., a Portland cement manufacturer, are the only non-CAIR sources expected to be affected by NY BART requirements as identified by MANE-VU and by NYDEC. As we understand, NYDEC will require BART-eligible Electric Generating Units (EGUs) to undergo a BART determination, even though the State promulgated the CAIR under 6 NYCRR Parts 243, 244, and 245. MANE-VU identified 19 EGUs in New York among the top 167 stacks in the

MANE-VU region for which a 90 percent reduction in S02 emissions is recommended by the RPO. Table 9-4 provides a listing of these units, along with the planned NOx and SO2 emission controls. However, without BART determinations accompanying the draft NY SIP, the reader is left wondering how these proposed emission controls were derived. A review of the listed proposed SO2 controls concludes that only two of the units will achieve 90 percent SO2 reduction.

Response: DEC recognizes that not all BART-eligible facilities were accounted for in the modeling. This is not possible given the uncertainty of the list of potential BART sources. However, the modeling done by the RPO (MANE-VU) identified the two largest BART-eligible sources in New York contributing to visibility impairment in downwind Class I areas. Modeling including just these two sources demonstrated that Reasonable Progress Goals will be achieved. Identifying and controlling additional BART-eligible sources, once they are identified (including EGUs that would not otherwise have been required to meet BART control requirements), and requiring controls can only improve the visibility beyond that projected in the SIP.

The expected control efficiencies listed in Table 9-4 are those presently planned under other portions of New York's air program, and are among those that will be evaluated for the best method by which 90% controls will be achieved. In the meantime, New York has committed to achieving 90% control for these source or the equivalent.

15. Comment: The low sulfur fuel oil reduction strategy outlined in Section 9.4c of the NY

draft SIP will revise the State's current fuel sulfur limits (6 NYCRR Part 225) and will implement NY's Reasonable Progress Goals. Since the expected effective date of these provisions is 2012, the NYDEC should consider requiring similar fuel sulfur limits in evaluating BART determinations.

Response: We understand that low sulfur fuel is a control measure for BART at facilities. Fuel sulfur limits are always evaluated as potential control options for those pollutants for which combustion is a contributing process.

16. Comment: Section 9.6 of the New York RH SIP references “eight" non-CAIR sources included in the modeling used to set reasonable progress goals that would likely be controlled under BART alone. The section clarifies that these sources appear in Table 9-6, but this table lists only two of these eight sources. If our understanding is correct, NYDEC should make it clear that these are the only two sources in NY among the eight sources referenced. Upon further discussion, the FLMs said if EPA doesn’t receive the states’ BART determinations by January 2010, EPA may do the BART determinations.

Response: Two BART sources were included in the modeling due to the high expectation that these sources will be subject to BART controls. See the response to comment 14 for additional detail.

The content of Table 9-4 is sufficiently explained in the text of Section 9.3. The New

York sources can easily be identified in the table's column and row titles, and labeling. We have included a map of New York State in the SIP which shows tentative EGU and non-EGU BART sources.

17. Comment: Section 8.3, page 8-4 - NY's BART rule is expected to provide source owners with the opportunity to conduct "exemption modeling" that demonstrates that the candidate sources do not cause or contribute to visibility impairment in Class I areas. This opportunity is not consistent with agreements made by MANE-VU States and therefore requires a discussion on how this deviation may or may not affect projects made by the MANE-VU organization.

Response: New York is not aware of entering into any agreement not to conduct exemption modeling, nor is this necessary to meet reasonable progress goals. If a potential BART source can demonstrate that its emissions do not "cause or contribute" to visibility impairment in any Class I area, the requirement to install BART controls will not apply under the federal rule, and sources should not be forced unnecessarily to install controls based on an RPO policy, especially to one that which New York has not agreed. Furthermore, arbitrarily requiring that controls be installed by sources that cannot be shown to have a visibility impact would be pointless and a waste of resources both for regulatory agencies and source owners. States have the option of choosing whether to allow for exemption modeling, and New York is fully justified in providing for it.

18. Comment: If NY does intend to reevaluate BART from the original eligible list, the State

should provide in the NY SIP the source names and descriptions that were developed and provided to MANE-VU for analysis several years ago. BART eligibility is based on Federal criteria, and there is no reason that it should be postponed due to the lack of a State rulemaking.

Response: A list of facilities at which potential BART-eligible sources is provided under Section 8.4 along with a New York State map showing their locations. New York cannot apply the requirements of the federal BART rule, including requiring the conduction of BART assessments by potential BART sources, until a state rule is in place. Upon completion of the state rule the BART determinations will be made and BART will be implemented on an expeditious schedule.

9.0 Reasonable Progress Goals (RPGs)

19. Comment: Section 9.1, bottom of page 9-2 - NYDEC commits "to reducing emissions at least equal to those predicted in the model, through the measures described above." Please either summarize the MANE-VU Contribution Assessment (Appendix A) or refer the reader to another section of the main body of the SIP describing this statement. The information presented is not sufficient to explain to the reader how NYDEC will meet this objective.

Response: As the SIP mentions, DEC is committed to reach this objective by implementing the MANE-VU recommendations. This is fully explained in Chapter 9, and specifically in Section 9.4.

20. Comment: Section 9.5, page 9-16 - NYDEC asserts that because the State does not contain a Class I area, the State has no requirement to evaluate NY's emission control strategy using the statutory four factors. This is not accurate. As a significant contributor to visibility impairment at one or more Class I areas, it is the State's responsibility to evaluate emission reduction controls, as the regulatory authority, for reasonableness based on the four factors for each Class I area. Although a State containing the Class I area or the RPO can suggest "reasonable" control levels, each State must make a final determination themselves.

If NYDEC agrees with the analysis of the four factors produced by MANE-VU (or someone else), please present the four factor analysis and clearly state that it represents NYDEC's view in this section.

Response: The language suggesting that New York is not required to evaluate NY's emission control strategy using the statutory four factors was incorrect and was removed.

The four-factor analysis is discussed in detail in section 9.2. Its application in New York is detailed in Section 9.4. The statement at the beginning of the section ("New York State is committed to reducing emissions at least equal to those predicted in the model, through the measures described above. These are reasonable measures designed to meet our CAA Section 110(a)(2)(D) obligations.") clearly indicates that New York accepts the four factor analysis in the SIP as the basis for the strategy for reducing visibility-impairing pollutants.

21. Comment: Section 9.8 forward - Air quality dispersion modeling results are presented showing improvements to PM concentration resulting from low sulfur fuel strategies and 90 percent reductions in SO2 to the 167 EGU stacks. Please provide narrative summarizing the State's description and performance evaluation of all models used. Please present performance assurances for both regional and State levels as well as whether model projections were used in relative or absolute sense. The language added in this recent draft SIP does not adequately address the information we are requesting. Again, as stated in our overall comment section, the modeling discussion does not provide enough detail of the caveats associated with the model to enable the reader to fully understand the limitations of the conclusions made based upon the output of the model and how they specifically apply to NY.

The added language does not include a narrative of the State's description and performance evaluation of all the models used; nor does it include a discussion that presents performance assurances for both regional and State levels including whether the models were used in a relative or absolute manner. Again, it is not enough to merely reference the Appendix containing the MANE-VU modeling report. The State must explain how the information was considered by NYDEC and how it was applied specifically to NY.

Response: A brief description of the models and the performance analysis was placed in the text in Section 9.5.1, and has been supplemented. All other detail can be found in Appendix R - “MANE-VU Modeling for Reasonable Progress Goals Model performance evaluation, pollution apportionment, and control measure benefits" as is appropriate.

22. <u>Comment:</u> Section 9.12, page 9-25 - The narrative communicates that because NY is a member of a group of States that are controlling emissions, and that because the group's strategy has been shown through computer modeling to meet the EPA's uniform glide slope guideline for all Class I areas, "NY will therefore meet its obligation under the SIP and Regional Haze Program." This is neither a reasonable nor an appropriate conclusion to make without further details provided in the SIP and a commitment that NY's strategies provide a "share" of reasonable progress.

In order to state that NY is meeting its obligations for the SIP and the Regional Haze program, the State must discuss its specific emission reductions and conclude that the reductions are "reasonable" based on the four factors. As part of this demonstration, the State may also examine its emission reductions that will provide for the State's "share" in reaching a specific Class I area's apportionment request.

For example, in section 7.6, when discussing the RPO and State emissions, NYDEC offered a before-and-after total of Statewide emission levels broken down by pollutant species. NYDEC could take this same approach in demonstrating the before-and-after of visibility impacts at the Class 1 areas affected by emissions originating in NY. If the regional modeling is not sufficient to demonstrate NY's contribution to extinction at the affected Class I areas; the SIP should document the changes in extinction achieved by the regional plan at these Class I areas, by pollutant species, and compare those overall extinction changes with changes in NY's emissions of the associated precursor emissions. This would help assure that the State is contributing its "share" toward reasonable progress. It may help to discuss the specific sources or regions with significant size/location relationships with a Class I area where controls are located. Although categorical controls are effective, specific control evaluation is very important because Class I areas are not evenly distributed geographically. If NYDEC believes that emissions reductions in any part of the State contributes more or less proportionally toward reductions in associated visibility impairing aerosols in all the affected Class I areas, then the SIP should present that working assumption in support of an assessment of statewide reductions as meeting reasonable progress requirements.

Response: A description of the four factor analysis and the reasonable reductions expected as a result of the analysis are contained in Section 9. The application of this analysis to New York is fully described in the SIP.

Emission reductions resulting from New York's are described in Section 7, Emissions Inventory. However, MANE-VU did not provide New York with state-specific extinction modeling information, nor does it appear to have been a product of the work done by MANE-VU. New York has agreed to implement controls to reduce emissions and has agreed to implement a reasonable control strategy as defined by the Class I states. DEC has thus made commitments to reduce emissions and improve visibility in Class I areas by agreeing to the reasonable measures proposed by MANE-VU.

23. Comment: The State must include in the SIP a discussion that reviews visibility

conditions in affected Class I areas before and after NY control efforts. Otherwise, there is no demonstration that the control efforts will be effective. The Regional Haze Rule makes the requirement for visibility apportionment from each State clear. At 40 CFR 51.308(d)(3)(ii), the rule states:

> "The State must demonstrate that it has included in its implementation plan all measures necessary to obtain its share of the emissions reduction needed to meet the progress goal for the area. If the State has participated in a regional planning process, the State must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through the process." (Italics are added for emphasis.)

It is reasonable to assume that in order for the State to ensure it has included all measures needed to achieve its apportionment that each State needs to know what that apportionment is. At 40 CFR 51.308(d)(3)(iii), the rule states:

> "The State may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants."

The claim that NY State-specific visibility apportionment is not required because MANE-VU has performed the analyses and the member States (including NY) have agreed on the measures to achieve the reasonable progress goal and approved the analyses is insufficient.

MANE-VU did not provide its member States with visibility apportionment information, so therefore NYDEC cannot make claim that it is relying on the RPO's technical analyses because the MANE-VU technical analyses are incomplete. The language in the rule assumes that the technical analyses done through the regional planning process included State-specific apportionment information. Furthermore, the rule states that every State must demonstrate that it has included in its SIP "all measures" necessary to obtain "its share of the emissions reduction" needed to meet the progress goal for the area. NYDEC cannot state or demonstrate that all measures necessary for NY are included in the SIP to meet area progress goals, when the State has no idea how its share of emission reductions will affect visibility in each Class I area.

<u>Response:</u> The comment incorrectly assumes that individual states must discuss their specific emission reductions. The citations provided from 51.308(d)(3), being extremely general, do not support this position. If anything, the second citation at 40 CFR 51.308(d)(3)(iii) validates New York’s level of analysis in this document SIP since control measures were identified “by relying on technical analyses developed by the regional planning organization and approved by all State participants.”

The control strategy developed in this SIP through MANE-VU was intended to derive a set of control measures based on the four-factor analysis that, if each state that is a member of the RPO adopts them, will enable the visibility of the Class I areas to meet the required reasonable progress goals. State-specific visibility apportionment information was not developed during the technical work conducted while this SIP was being developed and will not be available. A commitment on the part of New York to implement the control strategies requested by the Class I states (i.e., the "Ask") is sufficient evidence that New York will meet the reasonable progress goals. Only future monitoring data will be able to determine, if, in fact, the Class I area has met the reasonable progress goal.

DEC is committing to the level of reductions described in the MANE-VU Ask. The required 5-year progress reports and the mid-course review will allow the monitoring of progress and ensure that reasonable progress goals are being achieved.

24. Comment: The State has done a good job discussing its commitment to ensure that the New Source Review/Prevention of Significant Deterioration (PSD) Program in the State will work toward the interests of their regional haze goals. Please provide information on how NYDEC will use future permit review to contribute to progress in the regional haze process. Adding language that NYDEC intends to meet the requirement of full consultation with the FLMs for review of visibility impacts required by the NSR/PSD programs is one suggestion.

Response: The discussion of NSR/PSD in Section 10.3.3 (pp.10-31 through 10-33) contains this information, as well as detailing the need to involve FLMs in the review of projects affected by this program. Sections 10.8 and 10.10 additionally contain a description on how the requirements of the NSR/PSD program are applied through permitting.

10.0 Long Term Strategy

25. <u>Comment:</u> Section 10.2.2, page 1.0-6 - Consider adding tables similar to 10-1 to include future apportionment modeled predictions in both a percentage and mass basis.

<u>Response:</u> State-specific visibility apportionment information was not produced during the technical work conducted while this SIP was being developed, is not required or necessary, and will not be available.

26. <u>Comment:</u> Section 10.2.4, page 10-16, last paragraph - Simply stating that model performance was conducted by the provider is insufficient. Please provide a summary of RPO and State-level model performance of all tools utilized for the SIP. Please see comment 21.

<u>Response:</u> Please see the response to Comment 22.

27. <u>Comment:</u> Section 10.4.2, page 10-45 - The language added to this section in response to our initial comment is helpful. The language does a great job discussing MANE-VU's approach, but it doesn't include language that concludes that this approach is the approach for NY. Please elaborate in this section to include how the MANE-VU approach applies to the specific nature and sources within NY.

<u>Response:</u> Reviewers should refer to section 9.4 (especially section 9.4.1 which discusses New York's application of this approach in great detail) for the requested information on controls, and section 9.2.2 for the discussion on the application of the four-factor analysis in

deriving these control strategies.

28. <u>Comment:</u> Section 10.5.2, page 10-55 - The section on Agricultural and Forestry Smoke Management is exemplary.

<u>Response:</u> Comment acknowledged.

29. <u>Comment:</u> Section 10.7, page 10-62, second paragraph - This paragraph concludes that measures taken by NYDEC are reasonable and therefore, meet the State’s "share." More information is needed in order to substantiate this claim. Please see comment 21.

<u>Response:</u> Please see the response to Comment 22.

USDA Forest Service Comments Regarding
New York Draft Regional Haze Rule State Implementation Plan (SIP)

The air program staff of the U.S. Forest Service has reviewed the New York Draft Regional Haze State Implementation Plan (SIP) dated April, 2009, and has developed the comments listed below. We look forward to the New York Department of Environmental Conservation (NY DEC) response to these comments, as required in the Code of Federal Regulations (CFR) per section 40 CFR 51.308(i)(3). For further information regarding these comments, please contact Ralph Perron at (802) 222-1444 (rperron@fs.fed.us) or Rick Gillam at (404) 347-5058 (rgillam@fs.fed.us). The comments below are categorized by the emphasis areas outlined in our letter to Mr. David Shaw dated October, 13, 2006, included as Enclosure 2. That letter discussed our perspectives relevant to Regional Haze SIP preparation.

Overall Comments:

30. Comment: We are interested in the New York Regional Haze SIP because analyses conducted by MANE-VU have shown that air emissions sources located in New York affect visibility in Forest Service Class I areas in the states of Vermont and New Hampshire (see Section 1.4 of Draft SIP and Attachment B – MANE-VU Contribution Assessment). Overall, New York has done a commendable job compiling the Regional Haze SIP and addressing the requirements of the Regional Haze Rule. The following sections provide our comments related to specific sections of the Draft SIP.

Response: Comment acknowledged.

Specific Comments:

Natural Condition and Uniform Rate (Sections 5, 9 and 10 of Draft NY RH SIP)

- No comments.

Emission Inventories (Section 7 of Draft NY RH SIP)

- No comments

Area of Influence (Section 1of Draft NY RH SIP)

- No comments

Reasonable Progress Goals and Long Term Strategy (Sections 9 and 10 of Draft NY RH SIP)

- No comments

Wildland Fire (Section 10.5.2 of Draft NY RH SIP)

31. Comment: On May 6, 2009, we participated in a conference call with representatives from NY DEC to discuss questions related to the Draft Regional Haze SIP. Considering the information that was provided and discussions that occurred during the call, we request that the

following changes be made in Section 10.5.2.

- p. 10-55, 6 lines from bottom, please consider removing the phrase “Steps are taken to ensure that burning will not result in an increase in air pollution…” and replace with “Steps are taken to ensure that air quality impacts are minimized during burning…”
- p. 10-55, 13 lines from top, “Prescribed burns are those that are less than 10 acres in size.” Perhaps the state statute should be listed here, as prescribed burns may be larger than 10 acres in size.
- P. 10-55, 4 lines from bottom, “ …the prescribed burn plans for an area 10 acres or more must go through a State Environmental Review and Department review process.” Please consider adding a phrase that USDA Forest Service lands and Department of Defense lands are exempt from the review process for all prescribed burns. The Forest Service has processes in place to protect air quality and inform the public and communities prior to the initiation of prescribed burning activities on Forest Service lands and Ft. Drum. We will also continue to notify and keep the State of New York informed of our prescribed fire activities.

Response: The above changes have been made.

Regional Consistency (Section 3 of Draft NY RH SIP)

- No comments.

Verification and Contingencies

- No comments.

Coordination and Consultation (Section 3, 4 and 9.1, and 10.9 of Draft NY RH SIP)

- No comments.

Best Available Retrofit Technology (BART) (Section 8 of Draft NY RH SIP)

32. Comment: The Draft SIP does not contain emissions limitations representing Best Available Retrofit Technology (BART) for sources that have been determined to be BART-eligible. Section 8.0 of the draft SIP indicates that New York "has developed a strategy to implement BART that includes the adoption of a state rule that will contain the requirements for BART controls." Based on the discussion in Section 8.4 of the draft SIP, it appears that New York's BART Rule (if unchanged from that described) will address the requirements of the federal BART rule and will require controls to be in place by January 2013. We support New York's commitment to have the BART determinations completed and to have any necessary emissions controls in place by January 2013. We recognize that this date follows the 5-year timeframe outlined in the Federal BART Rule (based on the regulatory due date for the Regional Haze SIP of December 2007). However, we are concerned that since the process of conducting the BART determinations has not yet begun, and that New York's BART rule has not yet been finalized, it will be difficult for New York and the affected BART facilities to complete the

process by the January 2013 deadline. We encourage New York to move forward with the BART process as expeditiously as possible.

Response: New York cannot apply the requirements of the federal BART rule, including requiring the conduction of BART assessments by potential BART sources, until a state rule is in place. Upon completion of the state rule the BART determinations will be made and BART will be implemented on an expeditious schedule.

33. Comment: In our preliminary comments on the Draft SIP submitted for FLM review in February 2009, we requested that the Forest Service be provided a 60-day review period on BART determinations. NY DEC responded by stating "New York understands the U.S. Forest Service's need to review the BART determinations and commits to working with the Federal Land Managers (FLMs) and their other federal partners in implementing the BART program." We appreciate that New York recognizes the important role of the FLMs in the BART determination process. Section 8.4 of the Draft SIP provides a schedule for the NY BART rulemaking and describes the actions that will be taken to implement the rule. We request that a statement be added to Section 8.4 indicating that the FLMs will be provided a 60-day review period for the BART determinations, including any BART exemption modeling demonstrations.

Response: This statement has been added.

Additional Suggestions:

34. Comment: Page 10-41, 11 lines down from top, “Quebec’s five-year report on their reduction efforts to date discussed the measures taken from 2001 to 20054.” Should 20054 be corrected to 2005?

Response: This correction has been made.

United States
Environmental Protection
Agency

Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule

EPA-454/B-03-005
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Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program

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DISCLAIMER

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Abbreviations and Acronyms

b_{ext} - Total light extinction

CAA – Clean Air Act

CAAA – 1990 Clean Air Act Amendments

CASTNet - Clean Air Status and Trends Network

CM - Coarse mass

EPA – United States Environmental Protection Agency

f(RH) – Relative humidity adjustment factor

IMPROVE – Interagency Monitoring of protected Visual Environments

LAC - Light absorbing carbon

Mm^{-1} - Inverse megameter (10^{-6} m^{-1})

NAAQS – National Ambient Air Quality Standards

NWS - National Weather Service

OC - Organic carbon

OMC - Organic carbon mass

OP - Pyrolized organics

PM – Particulate matter

$PM_{2.5}$ – Particulate matter with an aerodynamic diameter less than 2.5 microns

PM_{10} – Particulate matter with an aerodynamic diameter less than 10 microns

RH - Relative humidity

SIP – State Implementation Plan

TOR - Thermal optical reflectance

Glossary of Terms

Aerosols – Suspensions of tiny liquid and/or solid particles in the air.

Coarse mass – Mass of particulate matter with an aerodynamic diameter greater than 2.5 microns but less than 10 microns.

Deciview (dv) - The unit of measurement of haze, as in the haze index (HI) defined below.

Default approach - The basic approach recommended by EPA to estimate the natural visibility conditions. States may choose to adopt the default values for natural visibility conditions or, with sufficient technical justification, propose alternatives to the basic approach or generate refined estimates. EPA believes that the default values that are provided in this document are adequately justified and believes that it can propose for approval States' use of them. However, EPA may not guarantee approval prior to receiving and fully considering public comment on any proposed actions.

Default values - the values obtained from adopting the default approach to estimating natural visibility conditions.

Fine particulate matter – particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2\ 5}$).

Fine soil – Particulate matter composed of material from the Earth's soil, with an aerodynamic diameter less than 2.5 microns. The fine soil mass is calculated from chemical mass measurements of fine aluminum, fine silicon, fine calcium, fine iron, and fine titanium as well as their associated oxides.

Haze index (HI) – A measure of visibility derived from calculated light extinction measurements, that is designed so that uniform changes in the haze index correspond to approximately uniform incremental changes in visual perception, across the entire range of conditions from pristine to highly impaired. The haze index [in units of deciviews (dv)] is calculated directly from the total light extinction [b_{ext} expressed in inverse megameters (Mm^{-1})] as follows:

$$HI = 10 \ln (b_{ext}/10)$$

Least-impaired days – The clearest, or least hazy, days.

Light absorbing carbon - Carbon particles in the atmosphere that absorb light; sometimes reported as elemental carbon.

Light extinction – A measure of how much light is absorbed or scattered as it passes through a medium, such as the atmosphere. The aerosol light extinction coefficient refers to the absorption and scattering by aerosols, and the total light extinction coefficient refers to the sum of the aerosol light extinction coefficient, the absorption coefficient of gases (such as NO_2), and the atmospheric light extinction coefficient due to molecular light scattering (Rayleigh scattering).

Mandatory Federal Class I areas – Certain National Parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence as of August 1977. Appendix A lists the mandatory Federal Class I areas.

Most impaired days – the dirtiest, or haziest, days.

Nitrate – Solid or liquid particulate matter containing ammonium nitrate [NH_4NO_3] or other nitrate salts. Atmospheric nitrate aerosols are often formed from the atmospheric oxidation of oxides of nitrogen (NO_x).

Organic carbon – Aerosols composed of organic compounds, which may result from emissions from incomplete combustion processes, solvent evaporation followed by atmospheric condensation, or the oxidation of some vegetative emissions.

Particulate matter – Material that is carried by liquid or solid aerosol particles with aerodynamic diameters less than 10 microns (in the discussions of this report). The term is used for both the in situ atmospheric suspension and the sample collected by filtration or other means.

Rayleigh scattering – Light scattering by gases in the atmosphere. At an elevation of 1.8 kilometers, the light extinction from Rayleigh scattering is approximately 10 inverse megameters (Mm^{-1}).

Relative humidity – The partial pressure of water vapor at the existing atmospheric temperature divided by the saturated vapor pressure of water at that temperature, expressed as a percentage.

Sulfate – Solid or liquid particulate matter composed of sulfuric acid [H_2SO_4], ammonium bisulfate [NH_4HSO_4], or ammonium sulfate [$(NH_4)_2SO_4$], or other sulfate salts. Atmospheric sulfate aerosols are often formed from the atmospheric oxidation of sulfur dioxide.

Total carbon – Sum of the light absorbing carbon and organic carbon.

Visibility impairment – Any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions. This change in atmospheric transparency results from added particulate matter or trace gases.

1. INTRODUCTION

1.1 What is regional haze?

Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. Visibility impairment is caused by particles and gases in the atmosphere. Some particles and gases scatter light while others absorb light. The net effect is called "light extinction." The result of the scattering and absorption processes is a reduction of the amount of light from a scene that is returned to the observer, and scattering of other light into the sight path, creating a hazy condition.

The primary cause of regional haze in many parts of the country is light scattering resulting from fine particles (i.e., particulate matter less than 2.5 microns in diameter, referred to as $PM_{2\ 5}$) in the atmosphere. These fine particles can contain a variety of chemical species including carbonaceous species (i.e., organics and elemental carbon), as well as ammonium nitrate, sulfates, and soil. Additionally, coarse particles between 2.5 and 10 microns in diameter can contribute to light extinction. Each of these components can be naturally occurring or the result of human activity. The natural levels of these species result in some level of visibility impairment, in the absence of any human influences, and will vary with season, daily meteorology, and geography.

1.2 What is meant by the term "natural visibility conditions?"

The term "natural visibility conditions" represents the ultimate goal of the regional haze program, consistent with the national visibility goal set forth in section 169A of the Clean Air Act (CAA). The national visibility goal is to remedy existing and prevent future human-caused impairment of visibility in mandatory Federal Class I areas. Regional haze strategies are to make reasonable progress towards this goal.

Natural visibility conditions represent the long-term degree of visibility that is estimated to exist in a given mandatory Federal Class I area in the absence of human-caused impairment. It is recognized that natural visibility conditions are not constant, but rather they vary with changing natural processes (e.g., windblown dust, fire, volcanic activity, biogenic emissions). Specific natural events can lead to high short-term concentrations of particulate matter and its precursors. However, for the purpose of this guidance and implementation of the regional haze program, natural visibility conditions represents a long-term average condition analogous to the 5-year average best-and worst-day conditions that are tracked under the regional haze program.

1.3 What is the purpose of the Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule?

The purpose of this document is to provide guidance to the States in implementing the regional haze program under the Clean Air Act. The regional haze regulations were published by EPA in 1999.[1] They are designed to protect visual air quality in 156 National Parks and wilderness areas (known as "mandatory Federal Class I areas"), across the country. As part of the program, States will develop goals and implement strategies for improving visibility in each mandatory Federal Class I area. Estimates of natural visibility conditions are needed by the States for the goal development process. This guidance document describes "default"[2] and "refined" approaches for estimating natural conditions. The EPA believes that natural conditions estimates developed using the default approach will be adequate to satisfy the requirements of the regional haze rule for the initial State implementation plan (SIP) submittals due no later than 2008.

This document provides guidance to EPA Regional, State, and Tribal air quality management authorities and the general public, on how EPA intends to exercise its discretion in implementing Clean Air Act provisions and EPA regulations, concerning the estimation of natural conditions under the regional haze program. The guidance is designed to implement national policy on these issues. Sections 169A and 169B of the Clean Air Act (42) U.S.C. § § 7491,7492 and implementing regulations at 40 CFR 51.308 and 51.309 contain legally binding requirements. This document does not substitute for those provisions or regulations, nor is it a regulation itself. Thus, it does not impose binding, enforceable requirements on any party, nor does it assure that EPA may approve all instances of its application, and thus the guidance may not apply to a particular situation based upon the circumstances. The EPA and State decision makers retain the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate. Any decisions by EPA regarding a particular SIP demonstration will only be made based on the statute and regulations, and will only be made following notice and opportunity for public review and comment. Therefore, interested parties are free to raise questions and objections about the appropriateness of the application of this guidance to a particular situation; EPA will, and States should, consider whether or not the recommendations in this guidance are appropriate in that situation. This guidance is a living document and may be

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[1] 64 Federal Register 35769, July 1, 1999.

[2] In the context of this guidance, the term "default" refers to the basic approach recommended by EPA to estimate the natural visibility conditions and the values obtained from adopting this approach. States are welcome to adopt the default values for natural visibility conditions or, with sufficient technical justification, to propose alternatives to the basic approach or to generate refined estimates. In theabsence of refinement, EPA recommends that the default values provided in this document be adopted.

revised periodically without public notice. The EPA welcomes public comments on this document at any time and will consider those comments in any future revision of this guidance document.

Readers of this document are cautioned not to regard statements recommending the use of certain procedures or defaults as either precluding other procedures or information or providing guarantees that using these procedures or defaults will result in actions that are fully approvable. As noted above, EPA cannot assure that actions based upon this guidance will be fully approvable in all instances, and all final actions may only be taken following notice and opportunity for public comment.

1.4 Does this guidance document apply to Tribal Class I areas as well as mandatory Federal Class I areas?

Not directly, although the procedures for estimating natural conditions that are described in this guidance can be used by Tribes if desired. The CAA and the regional haze rule call for the protection of visibility in 156 “mandatory Federal Class I areas.”[3] Tribes can establish Class I areas for the purposes of the prevention of significant deterioration (PSD) program, but the CAA does not provide for the inclusion of Tribal areas as mandatory Federal Class I areas subject to section 169A and 169B of the CAA. For this reason, progress goals and natural conditions estimates do not have to be established for Tribal Class I areas.

However, Tribes may find it advantageous for a number of reasons to participate in regional planning organizations (RPO) for regional haze and to develop regional haze tribal implementation plans (TIPs). Participation in an RPO may allow some Tribes to build capacity and enhance their air quality management capabilities. Under the Tribal Air Rule, Tribal governments may elect to implement air programs in much the same way as States, including development of Tribal implementation plans.[4] In this way, Tribes can work with other States and

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[3] Areas designated as mandatory Class I areas are those National Parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 areas, and all international parks which were in existence on August 7, 1977. Visibility has been identified as an important value in 156 of these areas. See 40 CFR part 81, subpart D. The extent of a Class I area includes subsequent changes in boundaries, such as park expansions. (CAA section 162(a)). States and tribes may designate additional areas as Class I, but the requirements of the visibility program under section 169A of the CAA apply only to "mandatory Class I areas," and do not affect these additional areas. For the purpose of this guidance document, the term “Class I area” will be used interchangeably with “mandatory Federal Class I area.”

[4] See 63 Federal Register 7254 (February 12, 1998), and 40 CFR Part 49.

Tribes on the development and adoption of specific emissions reduction strategies designed to protect air quality across a broad region including Tribal and State lands.

1.5 What is the statutory and regulatory background for the regional haze program?

In section 169A of the 1977 Amendments of the Clean Air Act, Congress established a national visibility goal as the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution." States are required to develop implementation plans that make "reasonable progress" toward this goal.

The EPA issued initial visibility regulations in 1980[5] that addressed visibility impairment in a specific mandatory Federal Class I area that is determined to be "reasonably attributable" to a single source or small group of sources. Regulations to address regional haze were deferred until improved techniques could be developed in monitoring, modeling, and in understanding the effects of specific pollutants on visibility impairment. The 1990 Clean Air Act Amendments included language in Section 169B to focus attention on regional haze issues. That section called for EPA to establish the Grand Canyon Visibility Transport Commission, and to issue regional haze rules within 18 months of receipt of a final report from the Commission. The EPA issued regional haze regulations in 1999.[6]

As noted in question 1.2 above, estimates of "natural visibility conditions," which are the national visibility goal of the Clean Air Act, are needed as part of the implementation process for the regional haze program.

1.6 What visibility metric will be used for estimating natural conditions, setting goals, and tracking progress?

According to the Regional Haze Rule, baseline visibility conditions, progress goals, and changes in natural visibility conditions must be expressed in terms of deciview (*dv*) units. The deciview is a unit of measurement of haze, implemented in a haze index (HI) that is derived from calculated light extinction, and that is designed so that uniform changes in haziness correspond approximately to uniform incremental changes in perception, across the entire range of conditions, from pristine to highly impaired. The HI is expressed by the following formula:

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[5] See 45 Federal Register 80084 (December 2, 1980).

[6] See 64 Federal Register 35713 (July 1, 1999). See also 40 CFR 51.300-309.

$$HI = 10 \ln(b_{ext}/10)$$

where

b_{ext} represents total light extinction expressed in inverse megameters (i.e., $Mm^{-1} = 10^{-6}\ m^{-1}$).

1.7 What are the key requirements and milestones for State implementation plans, pertaining to the estimation of natural visibility conditions under the regional haze rule?

The regional haze rule requires States to develop SIPs that include 1) reasonable progress goals for improving visibility in each mandatory Federal Class I area, and 2) a set of emission reduction measures to meet these goals. A State that does not have any Class I areas will not establish any progress goals in its SIP, but it is required to consult with nearby States having Class I areas that may be impacted by emissions from the State. A State without any Class I areas will also need to adopt emission reduction strategies to address its contribution to visibility impairment problems in Class I areas located in other States.

Specifically, a State is required to set progress goals for each Class I area in the State that:

- provide for an improvement in visibility for the 20% most impaired (i.e., worst visibility) days over the period of the implementation plan, and

- ensure no degradation in visibility for the 20% least impaired (i.e., best visibility) days over the same period.

Baseline visibility conditions for the 20% worst and 20% best days are to be determined using monitoring data collected during calendar years 2000-2004. Baseline conditions for 2000-2004, progress goals, and tracking changes over time are to be expressed in deciview units *via* the haze index.

Most States (and Tribes as appropriate) participating in regional planning organizations will submit regional haze implementation plans, including estimates of natural conditions and proposed progress goals, in the 2007-2008 time frame[7]. In developing any progress goal, the

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[7] Note that in the May 2002 American Corn Growers decision, the DC circuit court of appeals raised concerns with some of the deadlines for regional haze SIPs in the 1999 regional haze rule. While these issues are not fully resolved, EPA intends to seek solutions that will ensure that the schedule for regional haze implementation

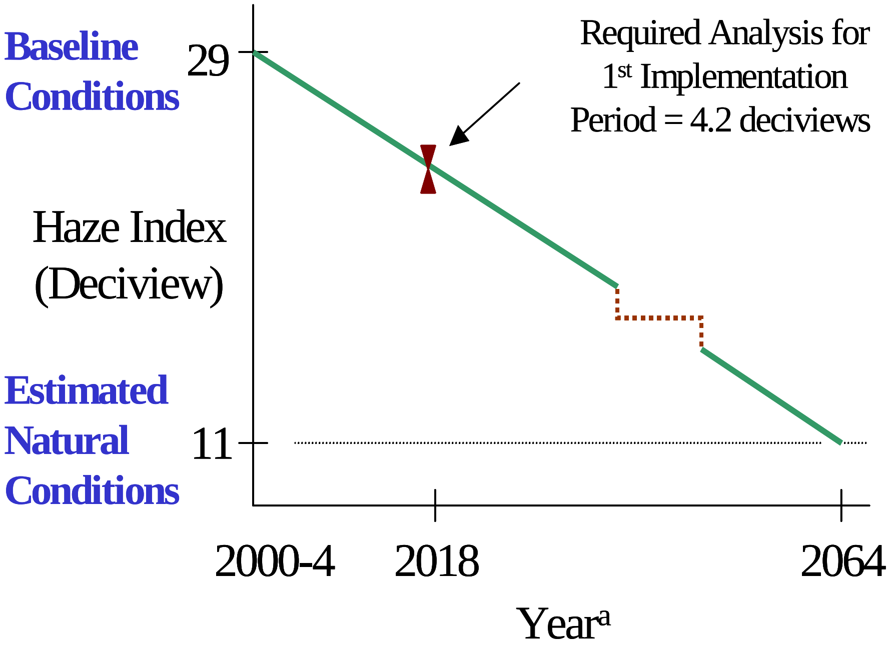

Figure 1-1 **Example of method for determining mandatory Federal Class I area rate of progress to be analyzed in SIP development process. ([a] HI values for 2004 are based on 2000-2004 data, etc.)**

State will need to analyze and consider in its set of options the rate of improvement between 2004 (when 2000-2004 baseline conditions are set) and 2018 that, if maintained in subsequent implementation periods, would result in achieving estimated natural conditions in 2064. In the example in Figure 1-1, baseline conditions for the 20% worst days exceed estimated natural conditions by 18 deciviews. The rate the State must analyze and consider for the 2018 progress goal is equal to 18 divided by 60 years = 0.3 deciviews per year x 14 years (2004 to 2018) = 4.2 deciviews. The State must demonstrate in the SIP whether it finds that this rate is reasonable or not, taking into consideration the relevant statutory factors. If it finds that this first rate is not reasonable, the State shall include a demonstration supporting its finding that an alternate rate is reasonable.

In order to determine the 2004-2018 progress rate for this analysis, the State should calculate baseline conditions in accordance with EPA guidance on tracking progress and use this guidance document for estimating natural conditions.

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plans is fully harmonized with the schedule for implementation plans addressing $PM_{2.5}$ nonattainment.

1.8 What other factors should be considered in developing progress goals?

Other important issues to be considered in developing mandatory Federal Class I area progress goals include the reasonable progress factors in the CAA, consultation with Tribes and other States, and emission reductions due to other Clean Air Act programs. The reasonable progress factors[8] to consider in developing any progress goal are:

- 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 existing source subject to such requirements.

The EPA plans to develop additional guidance on how to address these factors in the goal setting process.

Because visibility impairment results from human activities and their emissions transported over long distances - hundreds of miles in many cases - addressing impairment can be effective only through efforts among multiple States. For this reason, States are required to consult with other States (and Tribes, as appropriate) in developing mandatory Federal Class I area progress goals and long-term strategies to meet these goals. If a State is reasonably anticipated to cause or contribute to impairment in a mandatory Federal Class I area in another State, it is required to consult with that State on the development of that State's progress goals, and it must include strategies in its SIP that address its contribution to the haze in that State's mandatory Federal Class I area. Emissions reductions from other States may likewise be taken into account in setting mandatory Federal Class I area goals. The EPA supports the regional planning organization process currently under way as the most effective means to address the requirements of the regional haze program, and it is expected that much of the consultation, apportionment demonstrations, and technical documentation needed for SIPs will be facilitated and developed by the regional planning organizations.

Progress goals should also take into account any emission reduction strategies in place or on the way in order to meet other Clean Air Act requirements. For example, emission reduction strategies implemented to attain the $PM_{2\ 5}$ and ozone NAAQS, and national mobile source measures such as the Tier II or heavy duty diesel regulations, should be taken into account in

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[8] See CAA section 169A(g).

developing mandatory Federal Class I area progress goals for regional haze. Thus, EPA does not expect any progress goals for regional haze to be less ambitious than the level of visibility improvement expected from other programs.[9]

1.9 What progress reviews and future SIP revisions are required under the regional haze rule?

After the initial SIPs are approved, States will conduct formal progress reviews (in the form of a SIP revision) every 5 years from the date of SIP submittal (e.g., in 2013 if the initial SIP is submitted in 2008). Progress will be reviewed in terms of changes in visibility based on monitoring data, and in terms of the implementation of emission reduction measures contained in the plan. If progress is not consistent with the visibility and emission reduction goals established in the original SIP, the State must evaluate the reason for lack of progress and take any appropriate further action. If the lack of progress is primarily due to emissions from within the State, then the State must revise its implementation plan within 1 year to include additional measures to make progress. If the lack of progress is primarily due to emissions from other States, then the State must reinitiate the regional planning process to address this problem in the next major SIP revision (e.g., in 2018). If the State finds that international emissions sources are responsible for a substantial increase in emissions in any Class I area or causing a deficiency in visibility progress, the State must submit a technical demonstration to EPA in support of its finding. Similarly, the State should submit a technical demonstration if the State finds that unusual events (e.g., large wildfires), have affected visibility progress during the 5-year period.[10] Given that progress is determined based upon long-term averaging, the EPA believes that it is unlikely that such events will have a significant effect in most cases. See Section 1.14 for additional information about consideration of natural emissions from fire.

States will be required to conduct a comprehensive SIP revision in 2018 and every 10 years thereafter. This process will involve re-evaluating rates of progress for each mandatory Federal Class I area within the State as noted above and establishing new visibility improvement goals for these areas. The revised SIP should also include any revised emission reduction measures needed to meet the new mandatory Federal Class I area progress goals.

1.10 Should estimates of natural visibility conditions reflect contemporary conditions and

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[9] See regional haze rule, 40 CFR Section 51.308(d) (1) (vi).

[10] 64 Federal Register 35747 (Thursday, July 1, 1999).

land use patterns, or historic conditions?

For the purposes of this guidance, estimates of natural visibility conditions should reflect contemporary conditions and land use patterns. That is, estimates should attempt to calculate the degree of visibility impairment that exists today, given current vegetative landscapes, when human emissions contributions are removed. We believe that this is a more practical approach than attempting to speculate about what visibility conditions would have existed under the vegetative landscapes that existed 3 or 4 centuries ago, i.e., prior to the arrival of European settlers.

1.11 What estimates of natural conditions are referenced in the regional haze rule and preamble?

Section 308(d)(2)(iii) of the regional haze rule states that "[natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques.]" In the preamble to the regional haze rule, EPA states that "it will be appropriate to derive regional estimates of natural visibility conditions by using estimates of natural levels of visibility-impairing pollutants in conjunction with the IMPROVE methodology for calculating light extinction from measurements of the five main components of fine particle mass (sulfate, nitrate, organic carbon, elemental carbon, and crustal material)." As described elsewhere in this document, in addition to the five main components of fine particle mass, terms for coarse particle mass and Rayleigh scattering are also included in the calculation of light extinction.

The 1991 peer-reviewed report of the National Acid Precipitation Assessment Program (NAPAP) provides annual average estimates of natural concentrations for these six main components of PM for the eastern and western regions of the country.[11] By applying assumptions for average extinction efficiencies for each PM component and for the effect of humidity, the NAPAP report also included estimates of natural visibility conditions on an annual average basis. Those estimates are equivalent to about 9.6 deciviews in the eastern region and 5.3 deciviews in the western region of the United States.

In the regional haze preamble, EPA used the NAPAP estimates for natural concentrations of PM mass components, but used assumptions for average extinction efficiencies and annual

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[11] National Acid Precipitation Assessment Program, 1991. Acid Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions – Causes and Effects. Table 24-6, Washington, DC.

average humidity, based on updated methodologies developed under the IMPROVE program. Using this approach, EPA found that an appropriate estimate for natural conditions for the 20% worst days would be approximately 11-12 deciviews in the east and 8 deciviews in the west.

The preamble further stated that "with each subsequent SIP revision, the estimates of natural conditions for each mandatory Federal Class I area may be reviewed and revised as appropriate as the technical basis for estimates of natural conditions improve." Possible approaches for refining natural conditions estimates are discussed later in this document.

1.12 How are the natural visibility conditions at a mandatory Federal Class I area determined?

The general approach to estimating natural visibility conditions is based on the IMPROVE methodology for calculating visibility extinction. Using estimates of the natural concentrations of the primary components of particulate matter, along with estimates of the extinction efficiencies of these species, and site-specific factors to account for the effects of relative humidity on light scattering by particles, values for the annual average light extinction at each mandatory Federal Class I area are calculated. Figure 1-2 summarizes the approach to estimating natural visibility conditions.

1.13 What approaches for estimating natural conditions are discussed in this guidance document?

Chapter 2 of this guidance document describes the default approach for estimating natural visibility conditions for each mandatory Federal Class I area. This approach (see Figure 1-2) relies on the NAPAP estimates for PM mass components and the IMPROVE methodology for calculating light extinction. Important enhancements incorporated in this approach include the use of 10-year average relative humidity data from more than 300 weather stations, for development of appropriate relative humidity adjustment factors (*f(RH)*), and statistical techniques for estimating values for the 20% most impaired and 20% least impaired days. The EPA believes that this approach provides an adequate estimate of natural conditions for the purpose of developing initial visibility improvement goals and expects to be able to propose to approve goals in SIP submissions relying on this approach.

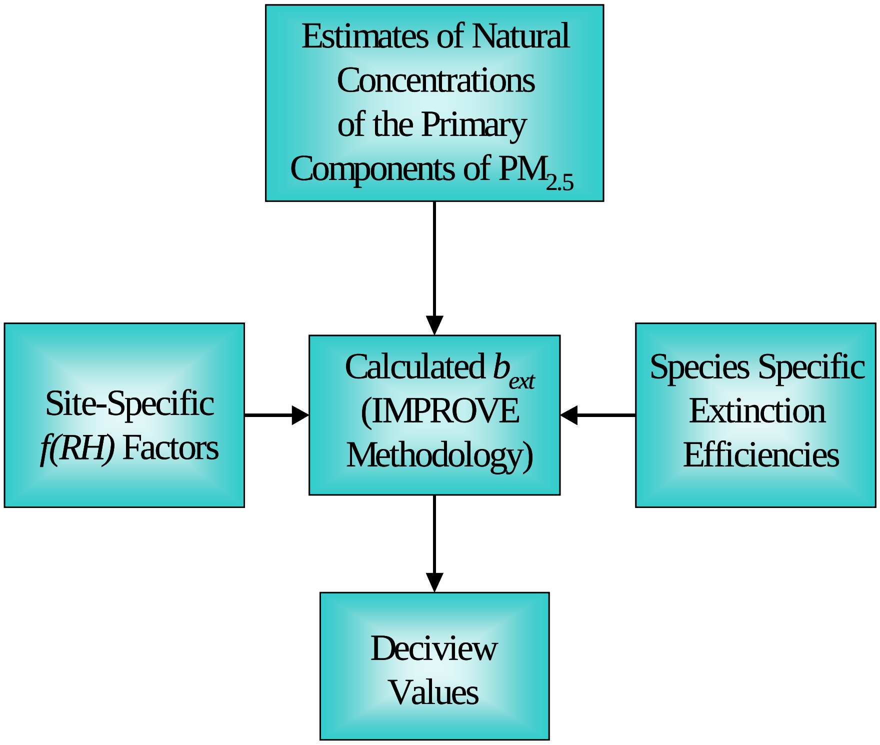

Figure 1-2 Types of Data Used in Approach for Estimating Natural Visibility Conditions

Chapter 3 of this guidance describes some alternative approaches by which States may refine their natural conditions estimates based on additional data and analyses. For example, one possible refined approach would involve updating the estimates of natural PM mass concentrations for each PM component, based on recent peer-reviewed literature, rather than using the NAPAP default values. These methods do not represent an exhaustive list and States are free to develop alternative approaches that will provide natural visibility conditions estimates that are technically and scientifically supportable. Any refined approach should be based on accurate, complete, and unbiased information and should be developed using a high degree of scientific rigor.

1.14 How are natural emissions from fire taken into account in estimates of natural PM and visibility levels?

Because some of the fires producing particulate emissions are naturally occurring, and would occur in the absence of human activities, the estimate of natural visibility conditions must take fire into account.

Appendix A of the NAPAP report discusses the approach used to estimate natural mass levels for each PM component. The estimates are based on compilations of natural versus man-made emission levels, ambient measurements in remote areas, and regression studies using man-made and/or natural tracers. Uncertainties are recognized in the estimates of each PM component. The report recognizes that estimated natural levels of both organic carbon and elemental carbon include contributions from fire emissions. The NAPAP report includes organic carbon as the most significant natural PM component by mass in both the eastern and western regions. Because most of the studies cited in the NAPAP Appendix were conducted in relatively remote areas, it is reasonable to assume that the contribution of fire to PM mass in the NAPAP estimates represents the natural regional contribution by fire. The NAPAP estimates included contributions from smoke but no distinction was made at the time between natural and man-made fire. Nonetheless, these are the best estimates available in the literature for current contributions from natural sources. Since the estimate of natural visibility conditions is a long-term (5-year) average, and because we expect to be able to further refine estimates over time based on improved information and methods, a regional contribution by fire emissions to overall natural visibility conditions should be adequate for the purpose of developing initial progress goals.

Data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time. Information from a number of additional activities and technical tools should be available over the coming years, including:

- implementation of a coordinated fire data system or fire tracking system;
- the collection of multiple years of speciated PM data in mandatory Federal Class I areas, and the assessment of potential contributions by natural fire events using data from the fire tracking system;
- development of chemical analysis techniques to identify carbon attributed to fire versus other sources;
- development of improved emissions factors and tracking of fire activity levels; and

- improved regional scale fire modeling, or remote sensing tools to retrospectively determine whether smoke from a fire impacted a Class I airshed.

1.15 How does the need to consider the fire component for natural visibility conditions interface with EPA's general policies regarding fire emissions?

The purpose of this document is to address the identification of methodologies for States to use in estimating natural visibility conditions, including the contribution from fire. This document is <u>not intended</u> to identify or dictate potential emission sources and control requirements.

The EPA acknowledges the need to allow the use of fire as an efficient and economical land management tool. The use of fire has proven benefits in maintaining the health of fire-tolerant and fire-dependent plant and animal ecosystems. In some cases, fire may be the only viable alternative to maintaining species diversity, enhancing productivity, or eliminating the threat of disease or catastrophic wildfires. The EPA, in partnership with the U.S. Department of Agriculture (USDA), and the Department of the Interior (DOI), will work with Federal and private land managers to develop alternatives to fire where applicable but will allow fire as a viable option in the maintenance of forest land and agricultural (cropland, rangeland, pastureland) ecosystems. The EPA has participated in the review of the USDA/DOI Wildland Fire Management Policies (1995 and 2001) and in the development of the 10-Year Comprehensive Strategy which establishes fire management priorities. The EPA is also actively involved with USDA and their Agricultural Air Quality Task force in addressing fire as a management tool for crop production and rangeland management. The EPA expects to amend the 1998 Interim Air Quality Policy on Wildland and Prescribed Fires to incorporate the final policy on burning for agricultural crop production and rangeland management. The EPA’s overall policy approach encourages the use of smoke management plans to minimize the impacts of burning activities on air quality and visibility impairment and provide some flexibility to areas with certified smoke management programs if it is determined that emissions from these fires contribute significantly to the National Ambient Air Quality Standards (NAAQS) violations.

States/tribes are aware of their responsibility to meet air quality standards and develop plans on how they will meet the standards. It is EPA’s view that smoke management plans are best negotiated and implemented at the local level, taking into account regional impacts, and that sources of emissions from burning are treated in an equitable manner. Recognizing the State’s responsibility to meet air quality standards, EPA encourages flexibility for local decisions on smoke management by States, locals, or tribal authorities. To address the NAAQS, reduce human health risk or exposure, or improve visibility in Class I areas, EPA encourages State and local air regulatory authorities to include their respective State/local agriculture, forestry, and park management agencies in stakeholder discussions and decisions, to ensure equitable and appropriate viable options for maintaining cropland, rangeland, pastureland, and forest land ecosystems while meeting air quality goals and standards.

The EPA understands the benefits of a tracking system to keep accurate accounting of fire emissions for emissions inventory, modeling, and attainment demonstrations and for the purposes of making sound decisions regarding burn and no burn days. The EPA is currently working with USDA and USDOI to develop a shared data system that would allow access to information useful to Federal, State, and local agencies. Some States or regional organizations have already started to develop their own tracking system for the area. The EPA is not endorsing any particular tracking system and will work with the States and regional planning organizations to make sure their tracking systems will interface with the Federal Tracking System to be developed.

In some cases, regional organizations have found it useful to classify fire emissions into two categories, natural and man-made, for the purposes of estimating natural visibility conditions. While EPA is not expressing an opinion on the importance of classifying fires, it supports those organizations who wish to do so for the purposes of estimating visibility conditions. However, the EPA does not require the distinction between natural and man-made fires. The EPA believes that it is important to recognize that any such classification of fire should not be construed to suggest any classification of emission sources for purposes of identifying those that are subject to control requirements. The criteria used to classify fires may or may not be the same criteria used to determine culpable sources and potential control requirements. Identifying culpable sources and potential control requirements to meet SIP requirements is beyond the scope and purpose of this document.

1.16 Can a State delay submittal of its control strategy SIP and associated mandatory Federal Class I area progress goals until it has developed a "refined" estimate of natural conditions?

No, States cannot use the development of a refined estimate of natural visibility conditions as a reason for delaying the submittal of regional haze control strategy SIPs required by statute and regulation. The EPA believes that the default approach to estimating natural visibility conditions presented in this document is adequate for the development of progress goals for the first implementation period under the regional haze rule. In addition, the timeline for implementing the regional haze program already includes a significant amount of lead time for developing these SIPs, and EPA does not believe that SIP due dates may be extended beyond the existing regulatory requirements. The EPA expects that States will need to begin assessing progress goals and emission reduction strategies beginning in the 2004-2005 time frame, in order to leave adequate time for air quality modeling, analysis of the statutory factors, consultation with other States or Tribes, development of regional recommendations, and adoption of individual State regulations by 2007-8. Because the process of planning and implementing strategies and evaluating progress is an iterative one, there will be future opportunities to refine progress goals based on new information about natural visibility conditions, rates of growth and development, and the effectiveness of controls.

2. DEFAULT APPROACH TO ESTIMATING NATURAL VISIBILITY CONDITIONS

This section of the guidance document presents the default approach to be used in estimating the natural visibility conditions for both the 20% most and 20% least impaired days.

2.1 What are the default estimates of the natural concentrations for the $PM_{2.5}$ components?

The estimates of the annual averages for the natural levels of fine particle constituents and of coarse particles are drawn from the 1990 report of NAPAP.[12] That report draws published data from a variety of sources and presents estimates for the natural levels of sulfates, organics, light absorbing carbon (also referred to as elemental carbon), ammonium nitrate, soil dust, and coarse particles for the eastern and western regions of the United States. The estimates presented in that report include significant uncertainties which indicate that the actual natural levels for these species are likely to fall within a range around the values reported. However, with minor adjustments, these estimates provide the starting point for calculating natural visibility conditions in the mandatory Federal Class I areas.

The approach to estimating natural conditions presented in the NAPAP report defines two separate regions of the United States: (1) the East, which consists of all the States east of the Mississippi River, and up to one tier of States west of the Mississippi; and (2) the West, including the desert/mountain regions of the Mountain and Pacific time zones. Geographically, these two subregions show strong differences in haze sources, vegetation, relative humidity, and regional haze levels. Within these two subregions, spatial variations in the natural aerosol levels would be expected. As a result, States near the boundary between East and West should choose which set of NAPAP estimates are most appropriate and adopt those values.

Table 2-1 presents the default estimated natural concentrations of the particulate species for the East and the West along with estimates of the dry extinction efficiencies for each species. These concentration estimates are used with the respective estimates of the dry extinction efficiencies to establish the light extinction attributed to natural sources in the East and West. As Table 2-1 shows, the natural concentration estimates differ between the East and West only in the concentrations of sulfate and organic species.

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[12] Trijonis, J.C., NAPAP State of Science & Technology, Vol. III, 1990.

Table 2-1 Average Natural Levels of Aerosol Components[a]

	Average Natural Concentration		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	0.47	1.40	2	4
Elemental carbon	0.02	0.02	2-3	10
Soil	0.50	0.50	1½ - 2	1
Coarse Mass	3.0	3.0	1½ - 2	0.6

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1 $\mu g/m^3$ and 0.2 $\mu g/m^3$ of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 $\mu g/m^3$ and 1.5 $\mu g/m^3$ of organic compounds.

2.2 What should be done if the default estimate for any naturally contributed species exceeds the corresponding measured concentrations?

Contributions by natural sources to haze are defined as "those not from man-made sources," accordingly, neither natural nor man-made contributions to haze can exceed the total haze levels over any period of time. The default natural concentration estimates are for long-term average conditions, and so may be larger than the measured current concentrations for short periods, but should not exceed the average concentration over several annual cycles. If the average measured level of any of the six particle species (for the baseline period, or for any other 5-year period), is smaller than the corresponding default natural values, then the default values should be replaced by values that are equal to or less than the measured values. This would constitute a refinement of the default as discussed in Section 3.

2.3 How are the long-term relative humidity data used to determine f(RH) values?

The U.S. EPA recently sponsored a project to examine measured hourly relative humidity data over a 10-year period (1988-1997) within the United States, to derive month-specific climatological mean humidity correction factors for each mandatory Federal Class I area.[13] These relative humidity (RH) factors were calculated from available hourly relative humidity data from 292 National Weather Service (NWS) stations across the 50 States and the District of Columbia, as well as from 29 IMPROVE and IMPROVE protocol monitoring sites, 48 Clean Air Status and Trends Network (CASTNet) sites, and 13 additional sites administered by the National Park Service.

The hourly RH measurements from each site were converted to hourly *f(RH)* values using a non-linear weighting factor curve, based on a modified ammonium sulfate growth curve (see Appendix A), applied to the 10 years of surface relative humidity data.

The annual average *f(RH)* values for all mandatory Federal Class I areas are tabulated in Appendix A of this document. Those values are used in the default approach to establishing natural visibility conditions. The 12 monthly averaged *f(RH)* values for each of these Class I areas are also tabulated in Appendix A. In most regions there is a seasonal cycle of relative humidity, which is evident in the appropriate monthly *f(RH)* values. The monthly *f(RH)* values may be used in refined estimates of the natural visibility conditions (Chapter 3). Note that Table A-2 and supplementary Table A-3 only includes f(RH) values for the designated mandatory Federal Class I areas. However, the software program needed to calculate *f(RH)* values for other sites is available for use by States, Tribes, and other agencies or interested parties, upon request to EPA.

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[13] U.S. EPA, Interpolating Relative Humidity Weighting Factors to Calculate Visibility Impairment and the Effects of IMPROVE Monitor Outliers, prepared by Science Applications International Corporation, Raleigh, NC, EPA Contract No. 68-D-98-113, August 30, 2001.

2.4 How is the default natural light extinction at a mandatory Federal Class I area calculated?

The calculation of natural light extinction is based on the IMPROVE methodology. Using the values in Table 2-1, the natural light extinction can be calculated from Equation 1:

$$\begin{aligned} b_{ext} = {} & (3) f(RH)[SULFATE] + \\ & (3) f(RH)[NITRATE] \\ & +(4)[OMC] \\ & +(10)[LAC] \\ & +(1)[SOIL] \\ & +(0.6)[CM] \\ & +10 \end{aligned} \tag{1}$$

where b_{ext} is the calculated total light extinction in inverse megameters. (Note: A value of 10 Mm^{-1} is used for all mandatory Federal Class I areas as an estimate of the light extinction caused by the light scattering from gas molecules, i.e., Rayleigh scattering). Relative humidity correction factors, *f(RH)*, are included for the sulfate and nitrate species as these are hygroscopic (i.e., absorb water) and their extinction efficiencies change with relative humidity. Annual average site-specific *f(RH)* values for 154 of the 156 mandatory Federal Class I areas (Appendix A) have been determined from historical data and are used in the default approach to establish site-specific natural visibility conditions.

Example calculations with Equation 1 will illustrate the use of the default approach. Looking at two examples in the East, and referring to Table 2-1 for default concentrations and Appendix A for annual *f(RH)* values, we see that the natural total light extinction for the Acadia National Park (Maine) is:

$$\begin{aligned} b_{ext} &= 3(3.4)[0.23] + 3(3.4)[0.1] + 4[1.4] + 10[0.02] + 1[0.5] + 0.6[3.0] + 10 \\ &= 21.5\,Mm^{-1} \end{aligned}$$

Similarly, for the Everglades National Park (Florida) b_{ext} is:

$$\begin{aligned} b_{ext} &= 3(2.7)[0.23] + 3(2.7)[0.1] + 4[1.4] + 10[0.02] + 1[0.5] + 0.6[3.0] + 10 \\ &= 20.8\,Mm^{-1} \end{aligned}$$

In the West, we see that Bandelier National Monument (New Mexico) has a default natural light extinction of:

$$\begin{aligned} b_{ext} &= 3(1.9)[0.12] + 3(1.9)[0.1] + 4[0.47] + 10[0.02] + 1[0.5] + 0.6[3.0] + 10 \\ &= 15.6\,Mm^{-1} \end{aligned}$$

and Yellowstone National Park (Wyoming) has a default b_{ext} of:

$$\begin{aligned} b_{ext} &= 3(2.1)[0.12] + 3(2.1)[0.1] + 4[0.47] + 10[0.02] + 1[0.5] + 0.6[3.0] + 10 \\ &= 15.8\,Mm^{-1} \end{aligned}$$

The default natural light extinction values have been calculated by this approach for 154 of the 156 mandatory Federal Class I areas and are listed in Appendix B.

2.5 How are the default b_{ext} values used to estimate natural visibility in deciview units?

The default light extinction values are used to calculate estimates for the annual average HI values (in *dv* units) at each mandatory Federal Class I area. These default HI values are determined from Equation 2:

$$HI = 10\ln(b_{ext} / 10) \qquad \textbf{(2)}$$

where b_{ext} is the default total light extinction in Mm^{-1} as calculated by Equation 1. From the examples above, the default annual average HI value for Acadia National Park is:

$$\begin{aligned} HI &= 10\ln(21.5 / 10) \\ &= 7.7\ dv. \end{aligned}$$

For the Everglades National Park, the default HI value is:

$$\begin{aligned} HI &= 10\ln(20.8 / 10) \\ &= 7.3\ dv. \end{aligned}$$

The default HI value for Bandelier National Monument is:

$$\begin{aligned} HI &= 10\ln(15.6/10) \\ &= 4.4\ dv. \end{aligned}$$

and for Yellowstone National Park the default HI is:

$$\begin{aligned} HI &= 10\ln(15.8/10) \\ &= 4.6\ dv. \end{aligned}$$

The calculated annual average HI values for each mandatory Federal Class I area are presented in Appendix B along with the default total light extinction (b_{ext})values.

2.6 How are the 20% best visibility days and the 20% worst visibility days determined in the default approach?

The calculated HI value represents an estimate of the annual average of daily natural visibility in *dv* units. If daily HI values for the natural background visibility in *dv* units were available, those values could be arranged in order, and the averages of the best 20% and the worst 20% of the values could be calculated to establish the regional haze rule goals for each mandatory Federal Class I area. However, since daily natural visibility *HI* values are not available, the default approach provides only an estimate of the annual average natural background visibility, and the averages for the best and worst 20% must be estimated.

Ames and Malm[14] have shown that the frequency distributions of daily calculated *HI* values for sites in the East and in the West, can each be well represented by normal distributions. Consequently, the average *HI* values for the 20% best visibility days and the 20% worst visibility days can be estimated from 10th and 90th percentile *HI* values, respectively. That is,

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[14] Rodger Ames and William Malm, Recommendations for Natural Condition Deciview Variability: An Examination of IMPROVE Data Frequency Distributions, Proceedings of "Regional Haze and Global Radiation Balance - Aerosol Measurements and Models: Closure Reconciliation and Evaluation," October 2-5, 2002, Bend, Oregon.

since the frequency distributions appear to behave normally, the 10th and 90th percentile *HI* values (*p***10** and *p***90**, respectively) for a mandatory Federal Class I area can be estimated from the following equations:

$$p10 = \overline{HI} - 128sd \qquad \textbf{\textit{(3)}}$$

and,

$$p90 = \overline{HI} + 1.28sd \qquad \textbf{\textit{(4)}}$$

where *sd* represents the standard deviation (in *dv* units) of the daily *HI* values for that area, and $\overline{HI}$ is the annual average of the *HI* values. Estimates of *sd* for current visibility conditions for eastern and western sites were derived from a database of current visibility conditions. At each site, daily *HI* values were calculated from the calculated light extinction values, and the mean and standard deviation of the daily *HI* values were determined. Comparison of sites within the same region showed that, in the East, the current visibility conditions have on average an *HI* value of approximately 18 *dv,* with an average *sd* of approximately 5 *dv*. In the West, the current visibility conditions showed an average *HI* of approximately 8 *dv* and an average *sd* of approximately 2.4 *dv*. More important in the present context, by inspection of the relationships between *sd* and *HI*, Ames and Malm[14] inferred best estimates of the *sd* values for natural visibility in both the West and East. In the West this best estimate of the natural visibility *sd* is 2 *dv,* whereas in the East the best estimate of the natural visibility *sd* is 3 *dv.*

These estimates of the standard deviation of natural contributions to visibility impairment can be used in Equations 3 and 4 above, along with the default natural *HI* values, to estimate the averages of the 20% best and 20% worst natural visibility contributions.

For example, the calculated 10th and 90th percentile natural *HI* values for Acadia National Park are:

$$p10 = 7.7 - 1.28(3) = 3.8$$
$$p90 = 7.7 + 1.28(3) = 11.5$$

Appendix B provides the default 10th and 90th percentile natural visibility *HI* values in *dv* units for each of the 156 mandatory Federal Class I areas. Figure 2-1 is a map of the 10th percentile default *HI* at mandatory Federal Class I areas across the United States, indicating a range from approximately 2 *dv* in the West to 4 *dv* in the East. Figure 2-2 is a map of the 90th percentile *HI*, which ranges from approximately 7 *dv* in the west to 11 dv in the East. Note that different color scales apply to the East and West portions of Figures 2-1 and 2-2, as indicated in the figures. Higher natural *HI* values in the northwest than the southwest United States are due to higher RH in the northwest. Higher natural condition organic carbon mass concentrations in the East are primarily responsible for higher default 10th and 90th percentile natural *HI* values in the East relative to the western United States. As noted in Section 2.1, States near the boundary between East and West have the option of choosing which set of default natural background conditions to use.

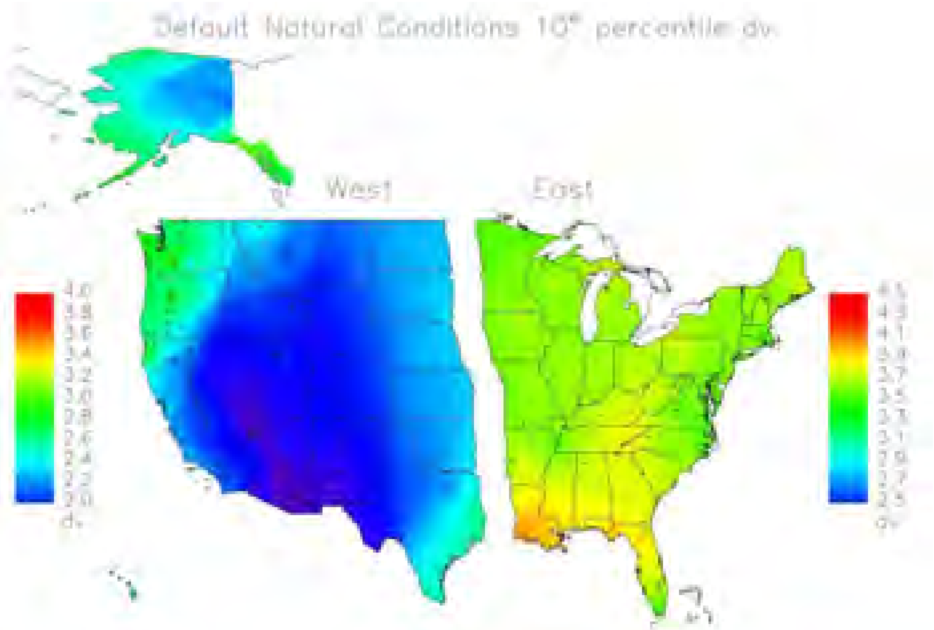

Figure 2-1 Estimates of the Default 10% Natural Haze Index Values (in *dv*)
(Note different color scales for the two parts of the figure)

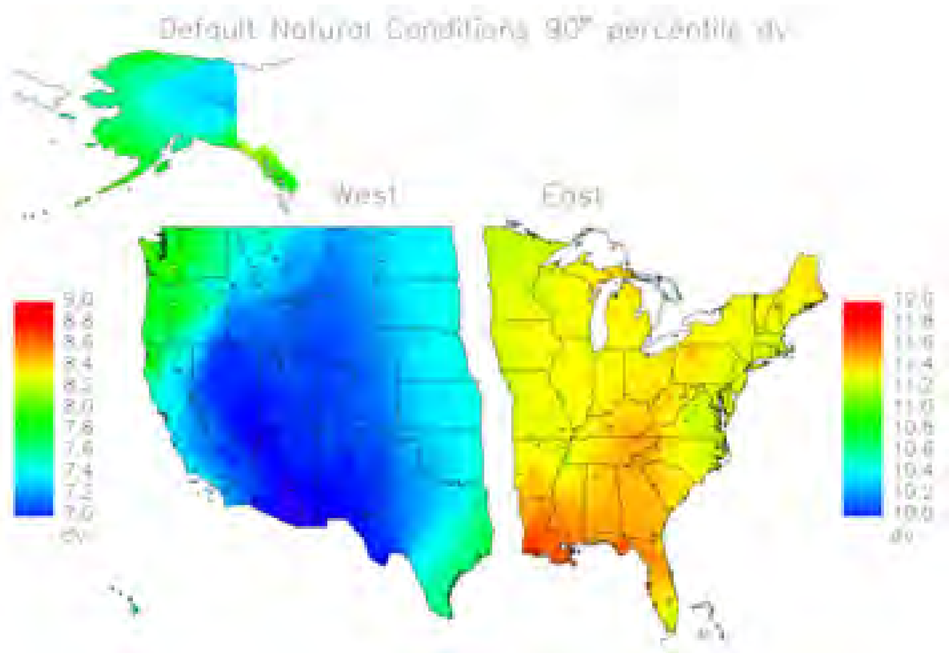

**Figure 2-2 Estimates of the Default 90% Natural Haze Index Values (in *dv*)
(Note different color scales for the two parts of the figure)**

3. REFINED ESTIMATION APPROACHES REGIONAL & SITE-SPECIFIC APPLICATION

3.1 Why might States want to use a refined approach to estimate natural visibility conditions?

There are a variety of circumstances under which States might wish to adopt a refined approach to estimating natural visibility conditions. For example, if the default estimates of the natural background conditions are close to the current visibility conditions, small uncertainties can have significant impacts on States' ability to meet SIP goals. In some regions, natural sources are known to exhibit predictable seasonal influences on visibility. Therefore, States might wish to use refined estimates of natural visibility conditions to account for these influences. Also, States which receive significant visibility impacts from biomass smoke might wish to distinguish more explicitly between man-made and natural sources. These examples are non-exhaustive, and there may be many other circumstances under which States find it desirable to develop more refined estimates. In all such cases, they should be prepared to support alternative approaches with sufficient information so that EPA and the reviewing public can verify their accuracy and validity.

3.2 What are some of the approaches that could be used by States to refine the default natural visibility estimates?

A refined approach is essentially one that uses species concentration estimates that differ from the NAPAP default values given in Table 2-1. Several possible refined approaches which can be adopted are described in this document, and States may identify others that are more appropriate for their own situations.

One possible refined approach is to revise the NAPAP default estimates of the natural concentrations of one or more of the composite components, and repeat the calculations with the refined concentrations. This approach might be adopted where there is an offset between the regional natural concentrations and the NAPAP default estimates. In this approach, the visibility calculations (i.e., Equations 1-4) would be carried out using refined annual average concentration estimates and the default annual average $f(RH)$ values. Note that any refined natural concentration estimates must retain the distinction between natural and anthropogenic components. For example, the natural concentration estimate for a species can never exceed the actual measured concentration of that species over a 5-year period.

In cases where constant values for natural species concentrations may not be appropriate, a second possible approach could estimate natural visibility using species concentrations that vary (e.g., seasonally, monthly, or climatologically). This approach might adopt the NAPAP default estimates for some species, and temporally varying estimates for others. Alternatively, the NAPAP estimates might be used for some seasons or time periods and other technically justified estimates or measurements for the remaining time periods. This approach would use the refined concentration estimates and if the time-varying species is hygroscopic (i.e., sulfate or nitrate), it would also use the appropriate monthly average *f(RH)* values (Appendix A).

Finally, a refined approach might account for infrequent natural events, such as forest fires or wind-blown dust, as major influences on visibility. Such an approach would require estimating the frequency and magnitude of the natural contribution to particle concentrations during the events.

3.3 Which refined approach is most appropriate for States to use?

To determine which approach is most appropriate, States should first identify whether any of the particle species concentrations are thought to deviate significantly from the NAPAP default values. Once identified, States should classify the deviations as either a constant offset (e.g., NAPAP sulfate values are too low near the sea coast), a systematic temporal variation (e.g., natural organics are seasonally higher in the summer), or an infrequent natural variation (e.g., dust produced by a natural sand dune area during wind events). The refinement of particle species concentrations could follow a range of different approaches, from using different annual average species concentrations, to using seasonal or monthly concentrations, to using different natural concentrations for individual sample events. Such refined approaches may require alternative methods to predict the 10th and 90th percentile natural condition *HI* values. The EPA encourages flexibility in the approaches used so that default and refined annual average, seasonal, monthly, and event-specific species concentrations may be intermingled to provide the best estimates of natural visibility for each of the mandatory Federal Class I areas.

3.4 What should States do if they want to use a refined approach, rather than the default approach to estimate natural visibility conditions?

States wishing to employ a refined approach should supply demonstrations that the refined approach is technically sound and provides regionally representative estimates of natural visibility conditions. The proposed refined approach must be based upon particle species classification into natural and man-made components (i.e., in any given time period, the natural particle species concentration cannot exceed the measured concentration), and should be submitted to EPA for approval prior to implementation.

States wishing to adopt a refined approach based on a constant offset of the natural concentrations of the particle species should provide technical justification for revising the NAPAP default concentrations. Using the refined concentrations, the natural visibility condition should then be calculated based on an approach that is consistent with the methodology that is used to track trends, such as the default approach.

States wishing to adopt a refined approach based on estimates of annually varying (seasonally, monthly, climatologically, etc.) natural particle concentrations should also provide technical justification for the estimates of the natural particle species concentrations. For example, if seasonal variations in particle species are the basis for the refined approach, then estimates should be provided of natural concentrations in every season for every pertinent species. Those particle species components that do not vary significantly should be treated using a constant estimate of the natural concentrations (e.g., use NAPAP value for each season).

In any case, the appropriate mechanism for putting a refined estimation approach in place is to incorporate the approach in a new or revised SIP. The justification for the proposed refined approach will thereby be considered as part of the normal SIP review process.

3.5 How might an infrequent natural impact be quantified?

Infrequent events affecting the visibility at specific mandatory Federal Class I areas could be addressed by using a constant or temporally varying value for species affected by the event during all non-event periods, and a different value for those same species for sampling periods during the event. For example, consider a forest fire, which affects particulate organic and elemental carbon. The contribution of the fire event to the natural levels of those species during the fire might be estimated by assuming all of the observed increment above the mean of the sample periods immediately pre- and post-fire event was the result of the fire. Multiple pre- and post-event sample periods could be used to strengthen the comparison. Alternatively, an air quality model might be used to estimate the impact of the smoke plume on particle carbon levels, or other air quality measurements might be used to estimate the impact of the event.

3.6 Can natural visibility estimates be made on a sample-period-by-sample-period basis?

Yes, such calculations can be done, but refined concentration estimates should be justified to support such an approach. In that case, the calculation of the current b_{ext} would first be done for each sample day, using Equation 1, the appropriate monthly *f(RH)* values, and the daily monitoring data for each species. The resulting daily b_{ext} values would then be converted to an *HI* value in *dv* units by Equation 2. Those *HI* values would then be sorted, and the highest 20% and lowest 20% identified, indicating the days with the most and the least visibility impairment, respectively. (This procedure is described in detail in a separate guidance document for tracking progress). For each of the days in these two groups, the natural contribution to light extinction would then be estimated. The average of each of these two groups of natural contributions would then be calculated.

As noted above, in any given time period the natural concentration of a species estimated by this calculation cannot exceed the actual measured concentration. Furthermore, if this approach is taken, natural visibility conditions (i.e., the averages of the 20% worst and 20% best natural *HI* values) should be estimated for as many years as possible to ensure that the average results are more representative of the long-term conditions.

Appendix A

Annual Average *f(RH)* and Monthly Average *f(RH)* Values at All Mandatory Federal Class I Areas

Appendix A
Origin of Relative Humidity and f(RH) Values

In terms of visibility reduction caused by fine particles, it is appropriate to treat relative humidity differently for different objectives. If the objective is the most reliable short-term estimate of visibility, then the measured or estimated relative humidity for the specific time and location of the aerosol speciation data is most appropriate. If the objective is to assess the long-term changes in man-made visibility impairment, it is appropriate to use relative humidity that is the same for the baseline period and future periods. In other words, it is more appropriate to eliminate the confounding effects of varying relative humidity, if the purpose is to track the visibility effects of air pollution emissions over extended time periods.

A number of approaches were considered to prevent variations in the relative humidity adjustment factor from confounding efforts to track progress related to emission controls. The simplest approach would use the same typical or overall average adjustment factor for all Class I areas at all times. However, this would enhance the contributions of hygroscopic particle species in dry locations and during typically dry seasons above what they truly should be while reducing their contributions in moist locations and seasons. Such distortions of the contributions to haze by hygroscopic particle species are unnecessary if a set of Class I area-specific adjustment factors are used that reflect seasonal changes in relative humidity.

A second approach would be to review relative humidity data over a long period of time to derive climatological estimates for relative humidity adjustment factors. These climatological estimates would then be used to estimate visibility extinction coefficients. These estimates are more likely to reflect "typical" relative humidity at the different mandatory Federal Class I areas during different times of year and, thus, are more likely to be more appropriate for establishing trends in visibility at the mandatory Federal Class I areas.

Recently, the U.S. EPA sponsored a project to examine measured hourly relative humidity data over a 10-year period within the United States, to derive month-specific climatological mean humidity correction factors for each mandatory Federal Class I area.[15] The results of that work are presented in the table below and the draft report is available at:

http://www.epa.gov/ttn/naaqs/pm/pm25_tech.html

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[15] U.S. EPA, Interpolating Relative Humidity Weighting Factors to Calculate Visibility Impairment and the Effects of IMPROVE Monitor Outliers, prepared by Science Applications International Corporation, Raleigh, NC, EPA Contract No. 68-D-98-113, August 30, 2001.

These relative humidity factors have been calculated from available hourly relative humidity data from 292 National Weather Service stations across the 50 States and District of Columbia as well as from 29 IMPROVE and IMPROVE protocol monitor sites, 48 CASTNet sites, and 13 additional sites administered by the National Park Service.

The hourly RH measurements from each site were converted to *f(RH)* values using a non-linear weighting factor curve, based on a modified ammonium sulfate growth curve. Values above 95% RH were set equal to the *f(RH)* corresponding to 95% RH. For days in which at least 16 hours of valid RH data were available, daily averages were determined from these hourly *f(RH)* values at each site. Monthly averages were then calculated from the daily *f(RH)* averages at each site.

The monthly average *f(RH)* values were interpolated at 1/4-degree increments using the inverse distance weighting technique (with a distance interpolation exponent of 1):

$$f(RH)_g = \frac{\sum f(RH)_w / x_{wg}}{\sum 1/x_{wg}}$$

where the monthly $f(RH)_g$ of the grid cell is calculated from $f(RH)_w$ at the weather station, and the horizontal distance between the grid cell center and the weather station, x_{wg}, summed over all the weather stations within a 250-mile radius with valid *f(RH)* values for that month.

In most regions there is a seasonal cycle of relative humidity which is accounted for by this process of appropriate *f(RH)* values for each month of the year from the daily-averaged values. Thus, the 12 monthly-averaged *f(RH)* values determined in this way for each Class I area should be used for all aerosol speciation data or model predictions for that location. However, a more complicated approach has also been investigated, as described below.

The regional haze regulation requires separate tracking of visibility changes for the worst 20% and best 20% of visibility days. If there is a significant correlation in any month at any site between daily relative humidity and the sulfate or nitrate concentrations, then use of the monthly-averaged *f(RH)* will systematically over- or under-predict the contribution to visibility impairment of the aerosol species. Fortunately, this concern can be tested at a number of locations in all regions of the country using the IMPROVE database. If the use of monthly-averaged values were found to cause large systematic biases in any region of the country, the Class I areas in those regions would require two *f(RH)* values for each month. One value would be the average *f(RH)* associated with relative humidity conditions that correspond to the worst 20% and the other value associated with relative humidity conditions that correspond to the best

20% of the light extinction values. Therefore there is the potential that some Class I area locations could require up to 24 *f(RH)* values for use in calculating extinction for aerosol data.

The U.S. National Park Service has tested this possibility, by examining data for each of the 12 months from 20 mandatory Federal Class I areas where relative humidity measurements are made. In nearly all cases, no statistically significant correlations were found between measured concentrations of SO_4^{2-}, NO_3^- and $[SO_4^{2-} + NO_3^-]$ vs. daily values of relative humidity in a large majority of months. Furthermore, deciview calculations were made using day-specific vs. climatological values for the relative humidity adjustment factor for each of 10 years in 15 mandatory Federal Class I areas. In 14 of the 15 areas, little if any difference was observed in the year to year calculations for the mean deciview values for the 20% worst and 20% best days, nor was there any difference in the trends. Some difference in the mean deciview value for the worst 20% days was observed in one mandatory Federal Class I area. However, the overall trend in the mean worst and best deciview values for this site was similar using the two types of *f(RH)* values. These results suggest there is a relatively weak correlation between hygroscopic components of PM and relative humidity and that the choice of a “climatological” vs. “day-specific” method for computing *f(RH)* has little apparent effect on observed trends in visibility. Consequently, the simpler climatological approach is used in regional haze calculations.

Table A-1 Values for f(RH) determined from the growth of ammonium sulfate

RH	f(RH)	RH	f(RH)	RH	f(RH)
1	1.00	34	1.00	67	2.03
2	1.00	35	1.00	68	2.08
3	1.00	36	1.00	69	2.14
4	1.00	37	1.02	70	2.19
5	1.00	38	1.04	71	2.25
6	1.00	39	1.06	72	2.31
7	1.00	40	1.08	73	2.37
8	1.00	41	1.10	74	2.43
9	1.00	42	1.13	75	2.50
10	1.00	43	1.15	76	2.56
11	1.00	44	1.18	77	2.63
12	1.00	45	1.20	78	2.70
13	1.00	46	1.23	79	2.78
14	1.00	47	1.26	80	2.86
15	1.00	48	1.28	81	2.94
16	1.00	49	1.31	82	3.03
17	1.00	50	1.34	83	3.12
18	1.00	51	1.37	84	3.22
19	1.00	52	1.41	85	3.33
20	1.00	53	1.44	86	3.45
21	1.00	54	1.47	87	3.58
22	1.00	55	1.51	88	3.74
23	1.00	56	1.54	89	3.93
24	1.00	57	1.58	90	4.16
25	1.00	58	1.62	91	4.45
26	1.00	59	1.66	92	4.84
27	1.00	60	1.70	93	5.37
28	1.00	61	1.74	94	6.16
29	1.00	62	1.79	95	7.40
30	1.00	63	1.83	96	9.59
31	1.00	64	1.88	97	14.1
32	1.00	65	1.93	98	26.4
33	1.00	66	1.98		

Table A-2 Recommended Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Representative IMPROVE Site Location

Class I Area	Site Name		Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Acadia	Acadia	1	ACAD1	ME	44 38	-68.37	3.2	2.8	2.8	3.2	3 2	3.3	3.7	3.7	3.9	3.5	3.4	3.5
Agua Tibia	Agua Tibia	100	AGTI1	CA	33 38	-116.87	2.4	2.3	2.4	2.2	2 2	2.2	2.2	2 3	2.3	2.2	2.1	2.2
Alpine Lakes	Snoqualmie Pass	80	SNPA1	WA	47 38	-121.37	5.3	5.0	3.7	3.6	4 2	3.1	3.5	3.4	3.8	4.9	5.5	5.3
Anaconda - Pintler	Sula	71	SULA1	MT	45.88	-114.12	3.4	3.0	2.6	2.3	2 3	2.2	1.9	1 8	2.0	2.5	3.3	3.4
Ansel Adams	Kaiser	110	KAIS1	CA	37.13	-119.12	3.0	2.7	2.5	2.1	2 0	1.7	1.7	1.7	1.8	1.9	2.3	2.7
Arches	Canyonlands	50	CANY1	UT	38 38	-109.87	2.6	2.3	1.8	1.6	1 5	1.2	1.3	1.5	1.5	1.6	2.0	2.3
Badlands	Badlands	59	BADL1	SD	43.63	-101.87	2.8	2.8	2.8	2.6	2 8	2.7	2.4	2.4	2.3	2.3	2.9	2.8
Bandelier	Bandelier	33	BAND1	NM	35 88	-106.37	2.3	2.1	1.8	1.6	1.6	1.4	1.7	2 0	1.9	1.7	2.0	2.3
Bering Sea (a)																		
Big Bend	Big Bend	31	BIBE1	TX	29.38	-103.12	1.8	1.7	1.5	1.4	1 5	1.5	1.6	1.8	1.9	1.7	1.7	1.7
Black Canyon of the Gunnison	Weminuche	55	WEMI1	CO	37.63	-107.87	2.5	2.3	2.0	1.7	1.7	1.5	1.7	2.0	1.9	1.7	2.2	2.4
Bob Marshall	Monture	73	MONT1	MT	47.13	-113.12	3.3	2.9	2.6	2.4	2.4	2.4	2.1	2.0	2.3	2.7	3.2	3.3
Bosque del Apache	Bosque del Apache	38	BOAP1	NM	33 88	-106.87	2.2	2.0	1.6	1.4	1.4	1.3	1.7	1.9	1.9	1.6	1.8	2.2
Boundary Waters Canoe Area	Boundary Waters	23	BOWA1	MN	47 88	-91.62	2.9	2.6	2.6	2.3	2 5	2.8	3.0	3.1	3.2	2.7	3.1	3.1
Breton	Breton	20	BRET1	LA	29.13	-89.12	3.5	3.3	3.3	3.3	3.4	3.6	3.8	3.8	3.6	3.4	3.4	3.5
Bridger	Bridger	65	BRID1	WY	42 88	-109.87	2.5	2.3	2.3	2.1	2.1	1.8	1.5	1.5	1.8	2.0	2.5	2.4
Brigantine	Brigantine	5	BRIG1	NJ	39.38	-74.37	2.9	2.6	2.7	2.6	2 9	3.0	3.2	3.4	3.4	3.2	2.8	2.9
Bryce Canyon	Bryce Canyon	49	BRCA1	UT	37.63	-112.12	2.6	2.4	2.0	1.6	1.5	1.3	1.3	1 5	1.5	1.6	2.0	2.4
Cabinet Mountains	Cabinet Mountains	75	CABI1	MT	47.88	-115.62	3.7	3.2	2.8	2.5	2.5	2.4	2.1	2.1	2.4	2.9	3.6	3.8
Caney Creek	Caney Creek	29	CACR1	AR	34.38	-94.12	3.3	3.0	2.7	2.8	3.2	3.2	3.0	3 0	3.2	3.2	3.1	3.3
Canyonlands	Canyonlands	50	CANY1	UT	38.38	-109.87	2.6	2.3	1.8	1.6	1.5	1.2	1.3	1 5	1.5	1.6	2.0	2.3
Cape Romain	Cape Romain	15	ROMA1	SC	32.88	-79.62	3.2	2.9	2.8	2.7	2.9	3.3	3.3	3.6	3.5	3.4	3.1	3.1
Capitol Reef	Capitol Reef	52	CAPI1	UT	38 38	-111.37	2.7	2.5	2.0	1.7	1.6	1.4	1.4	1.6	1.6	1.7	2.1	2.5
Caribou	Lassen Volcanic	90	LAVO1	CA	40.63	-121.62	3.7	3.1	2.8	2.4	2 3	2.1	2.0	2 0	2.1	2.3	3.1	3.5
Carlsbad Caverns	Guadalupe Mountains	32	GUMO1	TX	31.88	-104.87	2.4	2.0	1.6	1.4	1.6	1.5	1.9	2.2	2.4	1.7	1.9	2.3
Chassahowitzka	Chassahowitzka	18	CHAS1	FL	28.63	-82.62	3.5	3.2	3.1	3.0	3 0	3.5	3.5	3.7	3.7	3.5	3.4	3.6
Chiricahua NM	Chiricahua	39	CHIR1	AZ	32.13	-109.37	2.0	1.9	1.6	1.2	1 2	1.1	1.7	2.0	1.7	1.5	1.6	2.1
Chiricahua W	Chiricahua	39	CHIR1	AZ	32.13	-109.37	2.0	1.9	1.6	1.2	1 2	1.1	1.7	2 0	1.7	1.5	1.6	2.1
Cohutta	Cohutta	12	COHU1	GA	34.88	-84.62	3.4	3.1	2.9	2.7	3 2	3.6	3.6	3.7	3.7	3.5	3.2	3.4
Crater Lake	Crater Lake	86	CRLA1	OR	42 88	-122.12	4.6	4.0	3.7	3.5	3 2	2.9	2.6	2.7	2.9	3.6	4.6	4.7
Craters of the Moon	Craters of the Moon	69	CRMO1	ID	43 38	-113.62	3.1	2.7	2.3	2.0	2 0	1.8	1.4	1.4	1.6	2.0	2.7	3.0
Cucamonga	San Gabriel	93	SAGA1	CA	34.38	-118.12	2.6	2.5	2.5	2.2	2 2	2.1	2.2	2.2	2.3	2.2	2.2	2.3
Denali	Denali	102	DENA1	AK	63.75	-148.75	2.5	2.3	2.1	1.9	1 8	2.1	2.5	2 9	2.8	3.0	2.9	3.0
Desolation	Bliss	95	BLIS1	CA	38 88	-120.12	3.2	2.8	2.5	2.0	1 9	1.6	1.5	1.5	1.7	1.8	2.4	3.0
Diamond Peak	Crater Lake	86	CRLA1	OR	42 88	-122.12	4.6	4.0	3.7	3.5	3 2	2.9	2.6	2.7	2.9	3.6	4.6	4.7
Dolly Sods	Dolly Sods	8	DOSO1	WV	39.13	-79.37	3.0	2.7	2.7	2.5	3 5	3.1	3.2	3 5	3.5	3.1	2.8	3.1
Dome Land	Dome Land	109	DOME1	CA	35.63	-118.12	2.6	2.3	2.2	1.9	1 9	1.8	1.8	1.8	1.9	1.9	2.0	2.2
Eagle Cap	Starkey	76	STAR1	OR	45.13	-118.62	4.3	3.8	3.2	2.9	2.7	2.4	2.0	2.1	2.4	3.3	4.2	4.5
Eagles Nest	White River	56	WHRI1	CO	39.13	-106.87	2.2	2.2	2.0	2.0	2 0	1.7	1.8	2.1	2.1	1.8	2.1	2.1
Emigrant	Yosemite	96	YOSE1	CA	37.63	-119.62	3.0	2.9	2.7	2.2	2.1	1.7	1.5	1.5	1.6	1.8	2.3	2.7
Everglades	Everglades	19	EVER1	FL	25.38	-80.62	2.6	2.5	2.5	2.3	2.3	2.6	2.5	2 8	2.9	2.7	2.5	2.6
Fitzpatrick	Bridger	65	BRID1	WY	42 88	-109.87	2.5	2.3	2.3	2.1	2.1	1.8	1.5	1 5	1.8	2.0	2.5	2.4
Flat Tops	White River	56	WHRI1	CO	39.13	-106.87	2.2	2.2	2.0	2.0	2 0	1.7	1.8	2.1	2.1	1.8	2.1	2.1

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Class I Area	Site Name		Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Galiuro	Chiricahua	39	CHIR1	AZ	32.13	-109.37	2.0	1.9	1.6	1.2	1 2	1.1	1.7	2.0	1.7	1.5	1.6	2.1
Gates of the Mountains	Gates of the Mountains	74	GAMO1	MT	46.88	-111.62	2.8	2.5	2.4	2.3	2.3	2.2	2.0	1 9	2.1	2.4	2.7	2.7
Gearhart Mountain	Crater Lake	86	CRLA1	OR	42.88	-122.12	4.6	4.0	3.7	3.5	3 2	2.9	2.6	2.7	2.9	3.6	4.6	4.7
Gila	Gila Cliffs	42	GICL1	NM	33.13	-108.12	2.1	1.9	1.6	1.3	1 3	1.2	1.9	1.9	1.8	1.6	1.8	2.2
Glacier	Glacier	72	GLAC1	MT	48.63	-114.12	3.9	3.4	3.1	2.9	3 0	3.0	2.5	2.5	3.0	3.3	3.7	3.8
Glacier Peak	North Cascades	81	NOCA1	WA	48.63	-121.12	4.5	4.1	3.6	3.4	3 3	3.0	2.9	3.1	3.5	4.2	4.7	4.7
Goat Rocks	White Pass	79	WHPA1	WA	46.63	-121.37	4.8	4.2	3.8	3.6	3.4	3.1	2.9	3.0	3.5	4.3	4.9	5.0
Grand Canyon	Grand Canyon, Hance	48	GRCA2	AZ	35.88	-111.87	2.5	2.4	2.0	1.6	1.4	1.2	1.4	1.7	1.7	1.7	2.0	2.3
Grand Teton	Yellowstone	66	YELL2	WY	44.63	-110.37	2.5	2.3	2.2	2.1	2.1	1.9	1.7	1.6	1.8	2.1	2.4	2.5
Great Gulf	Great Gulf	4	GRGU1	NH	44.38	-71.12	2.8	2.6	2.6	2.8	2 9	3.0	3.3	3 5	3.6	3.2	3.0	2.9
Great Sand Dunes	Great Sand Dunes	53	GRSA1	CO	37.63	-105.62	2.4	2.3	2.0	1.9	1 9	1.7	1.9	2.3	2.2	1.9	2.3	2.4
Great Smoky Mountains	Great Smoky Mountains	10	GRSM1	TN	35.63	-83.87	3.6	3.0	3.0	2.8	3 2	3.6	3.6	3.6	3.7	3.4	3.3	3.5
Guadalupe Mountains	Guadalupe Mountains	32	GUMO1	TX	31.88	-104.87	2.4	2.0	1.6	1.4	1.6	1.5	1.9	2.2	2.4	1.7	1.9	2.3
Haleakala	Haleakala	108	HALE1	HI	20.75	-156.25	2.7	2.6	2.5	2.5	2.4	2.3	2.4	2.4	2.3	2.5	2.7	2.6
Hawaii Volcanoes	Hawaii Volcanoes	107	HAVO1	HI	19 25	-155.25	3.0	2.9	2.9	2.9	2 9	2.9	3.0	3.0	3.0	3.0	3.3	3.0
Hells Canyon	Hells Canyon	77	HECA1	OR	44 88	-116.87	3.7	3.1	2.4	2.1	2 0	1.8	1.5	1.4	1.6	2.2	3.4	3.8
Hercules - Glade	Hercules - Glade	28	HEGL1	MO	36.63	-92.87	3.2	2 9	2.6	2.6	3 0	3.0	3.0	3.0	3.2	2.9	3.0	3.2
Hoover	Hoover	97	HOOV1	CA	38.13	-119.12	3.1	2.7	2.5	2.0	1 9	1.6	1.5	1.5	1.6	1.8	2.3	2.8
Isle Royale	Isle Royale	25	ISLE1	MI	47 38	-88.12	3.1	2.6	2.7	2.5	2.4	2.9	3.2	3.4	3.5	2.9	3.3	3.3
James River Face	James River Face	7	JARI1	VA	37.63	-79.62	2.9	2.7	2.6	2.4	2 9	3.1	3.2	3.3	3.4	3.0	2.7	3.0
Jarbidge	Jarbidge	68	JARB1	NV	41 88	-115.37	2.9	2.6	2.1	2.1	2 2	2.0	1.6	1.4	1.4	1.6	2.4	2.8
John Muir	Kaiser	110	KAIS1	CA	37.13	-119.12	3.0	2.7	2.5	2.1	2 0	1.7	1.7	1.7	1.8	1.9	2.3	2.7
Joshua Tree	Joshua Tree	101	JOSH1	CA	34.13	-116.37	2.4	2.3	2.3	2.0	2 0	1.9	1.5	2.0	2.0	2.0	1.9	2.1
Joyce Kilmer - Slickrock	Great Smoky Mountains	10	GRSM1	TN	35.63	-83.87	3.6	3.0	3.0	2.8	3 2	3.6	3.6	3.6	3.7	3.4	3.3	3.5
Kaiser	Kaiser	110	KAIS1	CA	37.13	-119.12	3.0	2.7	2.5	2.1	2 0	1.7	1.7	1.7	1.8	1.9	2.3	2.7
Kalmiopsis	Kalmiopsis	89	KALM1	OR	42.63	-124.12	4.5	3.9	3.7	3.5	3 3	3.1	2.9	3 0	3.1	3.6	4.4	4.4
Kings Canyon	Sequoia	98	SEQU1	CA	36 38	-118.87	2.9	2.6	2.5	2.2	2.1	1.8	1.7	1.7	1.8	1.9	2.3	2.5
La Garita	Weminuche	55	WEMI1	CO	37.63	-107.87	2.5	2.3	2.0	1.7	1.7	1.5	1.7	2 0	1.9	1.7	2.2	2.4
Lassen Volcanic	Lassen Volcanic	90	LAVO1	CA	40.63	-121.62	3.7	3.1	2.8	2.4	2 3	2.1	2.0	2.0	2.1	2.3	3.1	3.5
Lava Beds	Lava Beds	87	LABE1	CA	41.63	-121.62	4.0	3.4	3.1	2.8	2.6	2.4	2.2	2 2	2.4	2.8	3.6	4.0
Linville Gorge	Linville Gorge	13	LIGO1	NC	35.88	-81.87	3.2	3.0	2.9	2.7	3.2	3.6	3.6	3 9	3.9	3.4	3.1	3.2
Lostwood	Lostwood	62	LOST1	ND	48.63	-102.37	3.0	2.9	3.0	2.3	2 2	2.5	2.5	2.3	2.2	2.4	3.2	3.2
Lye Brook	Lye Brook	3	LYBR1	VT	43.13	-73.12	2.8	2.6	2.7	2.6	2 8	2.9	3.1	3.3	3.4	3.2	2.9	2.9
Mammoth Cave	Mammoth Cave	9	MACA1	KY	37.13	-86.12	3.3	3.0	2.9	3.0	4.1	4.7	4.6	3.5	3.5	3.2	3.1	3.4
Marble Mountain	Trinity	104	TRIN1	CA	40 88	-122.87	4.0	3.4	3.2	2.9	2.8	2.6	2.5	2.6	2.7	2.9	3.6	3.9
Maroon Bells - Snowmass	White River	56	WHRI1	CO	39.13	-106.87	2.2	2.2	2.0	2.0	2 0	1.7	1.8	2.1	2.1	1.8	2.1	2.1
Mazatzal	Ike's Backbone	46	IKBA1	AZ	34.38	-111.62	2.2	2.0	1.8	1.4	1.3	1.2	1.4	1.7	1.6	1.5	1.8	2.1
Medicine Lake	Medicine Lake	63	MELA1	MT	48 38	-104.37	3.0	2.9	2.9	2.2	2 2	2.4	2.4	2.1	2.2	2.3	3.1	3.1
Mesa Verde	Mesa Verde	54	MEVE1	CO	37.13	-108.37	2.8	2.6	2.2	1.7	1.7	1.3	1.7	2 0	1.9	1.8	2.2	2.6
Mingo	Mingo	26	MING1	MO	36.88	-90.12	3.2	2.9	2.7	2.6	2 9	3.0	3.1	3.1	3.2	2.9	3.0	3.2
Mission Mountains	Monture	73	MONT1	MT	47.13	-113.12	3.3	2.9	2.6	2.4	2.4	2.4	2.1	2 0	2.3	2.7	3.2	3.3
Mokelumne	Bliss	95	BLIS1	CA	38 88	-120.12	3.2	2.8	2.5	2.0	1 9	1.6	1.5	1.5	1.7	1.8	2.4	3.0
Moosehorn	Moosehorn	2	MOOS1	ME	45.13	-67.37	3.0	2.7	2.7	2.9	2 9	3.1	3.5	3.6	3.8	3.3	3.2	3.2

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Mount Adams	White Pass	79	WHPA1	WA	46.63	-121.37	4.8	4.2	3.8	3.6	3.4	3.1	2.9	3.0	3.5	4.3	4.9	5.0
Mount Baldy	Mount Baldy	43	BALD1	AZ	34.13	-109.37	2.2	2.1	1.7	1.4	1 3	1.2	1.6	1.9	1.7	1.6	1.9	2.3
Mount Hood	Mount Hood	85	MOHO1	OR	45.38	-121.87	4.6	4.1	3.7	3.6	3 2	3.0	2.7	2.8	3.2	4.1	4.8	4.8
Mount Jefferson	Three Sisters	84	THSI1	OR	44 38	-122.12	5.3	4.6	4.4	4.3	3 8	3.4	2.7	2.7	3.1	4.3	5.2	5.3
Mount Rainier	Mount Rainier	78	MORA1	WA	46 88	-122.12	5.3	4.7	4.4	4.3	3 9	3.7	3.4	3.6	4.2	5.1	5.5	5.6
Mount Washington	Three Sisters	84	THSI1	OR	44 38	-122.12	5.3	4.6	4.4	4.3	3 8	3.4	2.7	2.7	3.1	4.3	5.2	5.3
Mount Zirkel	Mount Zirkel	58	MOZI1	CO	40.63	-106.62	2.2	2.2	2.0	2.1	2 2	1.8	1.7	1.8	2.0	1.9	2.1	2.1
Mountain Lakes	Crater Lake	86	CRLA1	OR	42 88	-122.12	4.6	4.0	3.7	3.5	3 2	2.9	2.6	2.7	2.9	3.6	4.6	4.7
North Absaroka	North Absoraka	67	NOAB1	WY	44.63	-109.37	2.4	2.2	2.2	2.1	2.1	1.9	1.6	1.5	1.8	2.0	2.3	2.4
North Cascades	North Cascades	81	NOCA1	WA	48.63	-121.12	4.5	4.1	3.6	3.4	3 3	3.0	2.9	3.1	3.5	4.2	4.7	4.7
Okefenokee	Okefenokee	16	OKEF1	GA	30.63	-82.12	3.3	3.0	3.2	3.0	3 2	3.8	3.4	3.6	3.6	3.4	3.3	3.4
Olympic	Olympic	83	OLYM1	WA	48.13	-122.87	4.2	3.9	3.6	3.5	2.9	3.2	2.7	3 3	3.8	4.3	4.5	4.4
Otter Creek	Dolly Sods	8	DOSO1	WV	39.13	-79.37	3.0	2.7	2.7	2.5	3.5	3.1	3.2	3 5	3.5	3.1	2.8	3.1
Pasayten	Pasayten	82	PASA1	WA	48.38	-119 87	4.6	4.1	3.5	3.3	3.2	2.9	2.8	2.9	3.4	4.1	4.7	4.8
Pecos	Wheeler Peak	35	WHPE1	NM	36.63	-105.37	2.4	2.2	1.9	1.8	1 8	1.6	1.8	2.1	2.1	1.8	2.2	2.4
Petrified Forest	Petrified Forest	41	PEFO1	AZ	35.13	-109.87	2.4	2.1	1.7	1.4	1 3	1.2	1.5	1.8	1.6	1.6	2.0	2.3
Pine Mountain	ke's Backbone	46	IKBA1	AZ	34 38	-111.62	2.2	2.0	1.8	1.4	1.3	1.2	1.4	1.7	1.6	1.5	1.8	2.1
Pinnacles	Pinnacles	92	PINN1	CA	36 38	-121.12	3.4	3.4	3.5	2.6	2.4	2.2	2.1	2 2	2.2	2.4	2.4	2.9
Point Reyes	Point Reyes	91	PORE1	CA	38.13	-122.87	3.6	3.2	3.1	2.6	2 5	2.3	2.4	2.4	2.5	2.5	2.9	3.3
Presidential Range - Dry River	Great Gulf	4	GRGU1	NH	44.38	-71.12	2.8	2.6	2.6	2.8	2 9	3.0	3.3	3.5	3.6	3.2	3.0	2.9
Rawah	Mount Zirkel	58	MOZI1	CO	40.63	-106.62	2.2	2.2	2.0	2.1	2 2	1.8	1.7	1 8	2.0	1.9	2.1	2.1
Red Rock Lakes	Yellowstone	66	YELL2	WY	44.63	-110.37	2.5	2.3	2.2	2.1	2.1	1.9	1.7	1.6	1.8	2.1	2.4	2.5
Redwood	Redwood	88	REDW1	CA	41.63	-124.12	3.8	3.6	3.8	3.6	3 8	3.9	4.2	4.2	3.7	3.4	3.6	3.4
Rocky Mountain	Rocky Mountain	57	ROMO1	CO	40 38	-105.62	1.9	2.0	2.0	2.1	2 3	2.0	1.9	1.9	2.0	1.8	2.0	1.9
Roosevelt Campobello	Moosehorn	2	MOOS1	ME	45.13	-67.37	3.0	2.7	2.7	2.9	2 9	3.1	3.5	3.6	3.8	3.3	3.2	3.2
Saguaro	Saguaro	40	SAGU1	AZ	32.13	-110.62	1.8	1.6	1.4	1.1	1.1	1.0	1.4	1.7	1.5	1.4	1.5	2.0
Saint Marks	Saint Marks	17	SAMA1	FL	30.13	-84.12	3.5	3.3	3.2	3.1	3 2	3.6	3.8	3.8	3.7	3.5	3.4	3.6
Salt Creek	Salt Creek	36	SACR1	NM	33 38	-104.37	2.2	1.9	1.5	1.5	1.6	1.5	1.7	1 9	2.0	1.7	1.8	2.0
San Gabriel	San Gabriel	93	SAGA1	CA	34.38	-118.12	2.6	2.5	2.5	2.2	2 2	2.1	2.2	2.2	2.3	2.2	2.2	2.3
San Gorgonio	San Gorgonio	99	SAGO1	CA	34.13	-116.87	2.5	2.6	2.4	2.1	2.1	1.8	1.7	1.8	1.9	1.8	1.9	2.1
San Jacinto	San Gorgonio	99	SAGO1	CA	34.13	-116.87	2.5	2.6	2.4	2.1	2.1	1.8	1.7	1.8	1.9	1.8	1.9	2.1
San Pedro Parks	San Pedro Parks	34	SAPE1	NM	36.13	-106.87	2.4	2.2	1.9	1.6	1.6	1.4	1.7	2 0	1.9	1.7	2.1	2.3
San Rafael	San Rafael	94	RAFA1	CA	34.63	-120.12	3.0	2.8	2.8	2.5	2 5	2.4	2.5	2.6	2.7	2.6	2.4	2.6
Sawtooth	Sawtooth	70	SAWT1	ID	44.13	-114.87	3.3	2.8	2.3	2.0	2 0	1.8	1.4	1.4	1.5	2.0	2.9	3.3
Scapegoat	Monture	73	MONT1	MT	47.13	-113.12	3.3	2.9	2.6	2.4	2.4	2.4	2.1	2.0	2.3	2.7	3.2	3.3
Selway - Bitterroot	Sula	71	SULA1	MT	45.88	-114.12	3.4	3.0	2.6	2.3	2 3	2.2	1.9	1.8	2.0	2.5	3.3	3.4
Seney	Seney	22	SENE1	MI	46.38	-85.87	3.3	2.8	2.9	2.7	2.6	3.0	3.3	3.6	3.7	3.3	3.5	3.4
Sequoia	Sequoia	98	SEQU1	CA	36.38	-118.87	2.9	2.6	2.5	2.2	2.1	1.8	1.7	1.7	1.8	1.9	2.3	2.5
Shenandoah	Shenandoah	6	SHEN1	VA	38.63	-78.37	2.9	2.6	2.7	2.4	2 9	3.1	3.2	3.5	3.5	3.0	2.7	2.9
Shining Rock	Shining Rock	11	SHRO1	NC	35 38	-82.87	3.3	3.0	2.9	2.7	3 2	3.6	3.6	3.9	3.9	3.5	3.2	3.3
Sierra Ancha	Sierra Ancha	45	SIAN1	AZ	34.13	-110.87	2.2	2.0	1.7	1.4	1 3	1.1	1.5	1 8	1.6	1.5	1.8	2.2
Simeonof	Simeonof	105	SIME1	AK	55.25	-160.75	4.2	4.2	3.8	4.0	4 2	4.6	5.0	5.2	4.5	3.7	3.9	4.2
Sipsey	Sipsey	21	SIPS1	AL	34 38	-87.37	3.3	3.0	2.8	2.7	3.1	3.4	3.5	3.5	3.5	3.3	3.1	3.3

Table A-2 Recommended Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Representative IMPROVE Site Location

Class I Area	Site Name		Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
South Warner	Lava Beds	87	LABE1	CA	41.63	-121.62	4.0	3.4	3.1	2.8	2.6	2.4	2.2	2.2	2.4	2.8	3.6	4.0
Strawberry Mountain	Starkey	76	STAR1	OR	45.13	-118.62	4.3	3.8	3.2	2.9	2.7	2.4	2.0	2.1	2.4	3.3	4.2	4.5
Superstition	Tonto	44	TONT1	AZ	33.63	-111.12	2.1	1.9	1.6	1.3	1 2	1.1	1.4	1.7	1.6	1.5	1.7	2.1
Swanquarter	Swanquarter	14	SWAN1	NC	35.38	-76.12	2.9	2.7	2.6	2.4	2.7	3.0	3.1	3.2	3.1	3.0	2.7	2.9
Sycamore Canyon	Sycamore Canyon	47	SYCA1	AZ	35.13	-111.87	2.4	2.4	2.0	1.6	1 5	1.2	1.5	2.0	1.9	1.8	2.0	2.3
Teton	Yellowstone	66	YELL2	WY	44.63	-110.37	2.5	2.3	2.2	2.1	2.1	1.9	1.7	1.6	1.8	2.1	2.4	2.5
Theodore Roosevelt	Theodore Roosevelt	61	THRO1	ND	46 88	-103.37	2.9	2.8	2.8	2.4	2.4	2.5	2.4	2 2	2.2	2.3	3.0	3.0
Thousand Lakes	Lassen Volcanic	90	LAVO1	CA	40.63	-121.62	3.7	3.1	2.8	2.4	2 3	2.1	2.0	2.0	2.1	2.3	3.1	3.5
Three Sisters	Three Sisters	84	THSI1	OR	44 38	-122.12	5.3	4.6	4.4	4.3	3 8	3.4	2.7	2.7	3.1	4.3	5.2	5.3
Tuxedni	Tuxedni	103	TUXE1	AK	59.75	-152.75	3.6	3.4	2.9	2.8	2 8	2.9	3.6	3.9	3.8	3.4	3.5	3.7
UL Bend	UL Bend	64	ULBE1	MT	47.63	-108.62	2.6	2.4	2.4	2.3	2 2	2.1	1.9	1.8	1.9	2.2	2.6	2.6
Upper Buffalo	Upper Buffalo	27	UPBU1	AR	35 88	-93.12	3.2	2.9	2.6	2.7	3.1	3.1	3.0	3 0	3.2	3.0	3.0	3.2
Ventana	Pinnacles	92	PINN1	CA	36 38	-121.12	3.4	3.4	3.5	2.6	2.4	2.2	2.1	2.2	2.2	2.4	2.4	2.9
Virgin Islands (b)	Virgin Islands	106	VIIS1	VI	18.75	-155.75												
Voyageurs	Voyageurs	24	VOYA2	MN	48.38	-92.87	2.7	2.4	2.3	2.2	2 2	2.8	2.5	2.7	2.9	2.5	2.8	2.7
Washakie	North Absoraka	67	NOAB1	WY	44.63	-109.37	2.4	2.2	2.2	2.1	2.1	1.9	1.6	1.5	1.8	2.0	2.3	2.4
Weminuche	Weminuche	55	WEMI1	CO	37.63	-107.87	2.5	2.3	2.0	1.7	1.7	1.5	1.7	2.0	1.9	1.7	2.2	2.4
West Elk	White River	56	WHRI1	CO	39.13	-106.87	2.2	2.2	2.0	2.0	2.0	1.7	1.8	2.1	2.1	1.8	2.1	2.1
Wheeler Peak	Wheeler Peak	35	WHPE1	NM	36.63	-105.37	2.4	2.2	1.9	1.8	1 8	1.6	1.8	2.1	2.1	1.8	2.2	2.4
White Mountain	White Mountain	37	WHIT1	NM	33.38	-105.62	2.2	1.9	1.6	1.5	1.5	1.4	1.7	1 9	2.0	1.7	1.8	2.1
Wichita Mountains	Wichita Mountains	30	WIMO1	OK	34.63	-98.62	2.8	2.6	2.4	2.4	2.7	2.5	2.2	2.4	2.7	2.5	2.6	2.8
Wind Cave	Wind Cave	60	WICA1	SD	43.63	-103.37	2.5	2.5	2.5	2.5	2.6	2.5	2.2	2 2	2.1	2.2	2.6	2.5
Wolf Island	Okefenokee	16	OKEF1	GA	30.63	-82.12	3.3	3.0	3.2	3.0	3.2	3.8	3.4	3.6	3.6	3.4	3.3	3.4
Yellowstone	Yellowstone	66	YELL2	WY	44.63	-110.37	2.5	2.3	2.2	2.1	2.1	1.9	1.7	1.6	1.8	2.1	2.4	2.5
Yolla Bolly - Middle Eel	Trinity	104	TRIN1	CA	40 88	-122.87	4.0	3.4	3.2	2.9	2 8	2.6	2.5	2.6	2.7	2.9	3.6	3.9
Yosemite	Yosemite	96	YOSE1	CA	37.63	-119.62	3.0	2.9	2.7	2.2	2.1	1.7	1.5	1.5	1.6	1.8	2.3	2.7

a: No particulate matter sampling or visibility monitoring is conducted in the Bering Sea Wilderness.

b**:** *f(RH)* values for Virgin Islands National Park were not calculated because of the limited RH data available.

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Acadia	Acadia	1	ACAD1	ME	44.37	68.26	3.3	2.9	2.8	3.4	3.1	3.0	3.4	3.8	4.0	3.8	3.6	3.5
Agua Tibia	Agua Tibia	100	AGTI1	CA	33.41	116.98	2.4	2.4	2.4	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.1	2.2
Alpine Lakes	Snoqualmie Pass	80	SNPA1	WA	47.42	121.42	4.3	3.8	3.5	3.9	2.9	3.2	2.9	3.1	3.3	3.9	4.5	4 5
Anaconda - Pintler	Sula	71	SULA1	MT	45.98	113.42	3.3	2.9	2.5	2.4	2.4	2.3	2.0	1 9	2.1	2.5	3.2	3.3
Ansel Adams	Kaiser	110	KAIS1	CA	37.65	119.20	3.0	2.7	2.4	2.1	1.9	1.7	1.6	1.6	1.6	1.8	2.3	2.7
Arches	Canyonlands	50	CANY1	UT	38.64	109.58	2.6	2.3	1.8	1.6	1.6	1.3	1.4	1.5	1.6	1.6	2.0	2 3
Badlands	Badlands	59	BADL1	SD	43.74	101.94	2.6	2.7	2.6	2.4	2.8	2.7	2.5	2.4	2.2	2.3	2.7	2.7
Bandelier	Bandelier	33	BAND1	NM	35.78	106.27	2.2	2.1	1.8	1.6	1.6	1.4	1.7	2.1	1.9	1.7	2.0	2.2
Bering Sea (a)					60.45	172.79												
Big Bend	Big Bend	31	BIBE1	TX	29.31	103.19	2.0	1.9	1.6	1.5	1.6	1.6	1.7	2.0	2.1	1.9	1.8	1.9
Black Canyon of the Gunnison	Weminuche	55	WEMI1	CO	38.58	107.70	2.4	2.2	1.9	1.9	1.9	1.6	1.7	1.9	2.0	1.8	2.1	2.3
Bob Marshall	Monture	73	MONT1	MT	47.75	113.38	3.6	3.1	2.8	2.6	2.7	2.7	2.3	2.2	2.6	2.9	3.5	3 5
Bosque del Apache	Bosque del Apache	38	BOAP1	NM	33.79	106.83	2.1	1.9	1.6	1.4	1.4	1.3	1.8	2.0	1.9	1.6	1.8	2.2
Boundary Waters Canoe Area	Boundary Waters	23	BOWA1	MN	47.95	91.50	3.0	2.6	2.7	2.4	2.3	2.9	3.1	3.4	3.5	2.8	3.2	3.2
Breton	Breton	20	BRET1	LA	29.73	88.88	3.7	3.5	3.7	3.6	3.8	4.0	4.3	4.3	4.2	3.7	3.7	3.7
Bridger	Bridger	65	BRID1	WY	42.98	109.76	2.5	2.4	2.3	2.2	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.4
Brigantine	Brigantine	5	BRIG1	NJ	39.46	74.45	2.8	2.6	2.7	2.6	3.0	3.2	3.4	3.7	3.6	3.3	2.9	2.8
Bryce Canyon	Bryce Canyon	49	BRCA1	UT	37.62	112.17	2.6	2.4	1.9	1.6	1.5	1.3	1.3	1.5	1.5	1.6	2.0	2.4
Cabinet Mountains	Cabinet Mountains	75	CABI1	MT	48.21	115.71	3.8	3.3	2.9	2.6	2.7	2.7	2.3	2.2	2.6	3.0	3.7	3.9
Caney Creek	Caney Creek	29	CACR1	AR	34.41	94.08	3.4	3.1	2.9	3.0	3.6	3.6	3.4	3.4	3.6	3.5	3.4	3 5
Canyonlands	Canyonlands	50	CANY1	UT	38.46	109.82	2.6	2.3	1.7	1.6	1.5	1.2	1.3	1.5	1.6	1.6	2.0	2.3
Cape Romain	Cape Romain	15	ROMA1	SC	32.94	79.66	3.3	3.0	2.9	2.8	3.2	3.7	3.6	4.1	4.0	3.7	3.4	3.2
Capitol Reef	Capitol Reef	52	CAPI1	UT	38.36	111.05	2.7	2.4	2.0	1.7	1.6	1.4	1.4	1.6	1.6	1.7	2.1	2.5
Caribou	Lassen Volcanic	90	LAVO1	CA	40.50	121.18	3.7	3.1	2.8	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.0	3.4
Carlsbad Caverns	Guadalupe Mountains	32	GUMO1	TX	32.14	104.48	2.1	2.0	1.6	1.5	1.6	1.6	1.8	2.1	2.2	1.8	1.9	2.1
Chassahowitzka	Chassahowitzka	18	CHAS1	FL	28.75	82.55	3.8	3.5	3.4	3.2	3 3	3.9	3.9	4.2	4.1	3.9	3.7	3.9
Chiricahua NM	Chiricahua	39	CHIR1	AZ	32.01	109.39	2.0	2.0	1.6	1.3	1.3	1.1	1.8	2.1	1.8	1.5	1.6	2.2
Chiricahua W	Chiricahua	39	CHIR1	AZ	31.84	109.27	2.0	1.9	1.6	1.2	1.3	1.1	1.8	2.1	1.8	1.5	1.6	2.2
Cohutta	Cohutta	12	COHU1	GA	34.92	84.58	3.3	3.1	3.0	2.8	3.4	3.8	4.0	4.2	4.2	3.8	3.4	3 5
Crater Lake	Crater Lake	86	CRLA1	OR	42.90	122.13	4.6	3.9	3.7	3.4	3.2	3.0	2.8	2.9	3.1	3.6	4.6	4.6
Craters of the Moon	Craters of the Moon	69	CRMO1	ID	43.47	113.55	3.1	2.7	2.3	2.0	2.0	1.8	1.4	1.4	1.6	2.0	2.8	3.0
Cucamonga	San Gabriel	93	SAGA1	CA	34.25	117.57	2.5	2.4	2.4	2.2	2.1	2.1	2.1	2.2	2.2	2.2	2.1	2 2
Denali	Denali	102	DENA1	AK	63.72	148.97	2.5	2.3	2.1	1.9	1.9	2.2	2.5	3.0	2.8	2.9	3.0	3.1
Desolation	Bliss	95	BLIS1	CA	38.98	120.12	3.2	2.8	2.4	2.0	1 8	1.6	1.5	1.6	1.7	1.9	2.4	3 0
Diamond Peak	Crater Lake	86	CRLA1	OR	43.53	122.10	4.5	4.0	3.6	3.7	3 2	3.1	2.9	2.9	3.1	3.7	4.6	4.6
Dolly Sods	Dolly Sods	8	DOSO1	WV	39.11	79.43	3.0	2.8	2.8	2.6	3.1	3.4	3.5	3.9	3.9	3.3	3.0	3.1
Dome Land	Dome Land	109	DOME1	CA	35.70	118.19	2.5	2.3	2.2	1.9	1.8	1.8	1.8	1.8	1.8	1.9	2.0	2.2
Eagle Cap	Starkey	76	STAR1	OR	45.10	117.29	3.8	3.2	2.5	2.1	2.0	1.9	1.6	1.6	1.6	2.3	3.4	4.0
Eagles Nest	White River	56	WHRI1	CO	39.69	106.25	2.2	2.2	2.0	2.0	2.1	1.9	1.8	2.0	2.0	1.9	2.1	2.1

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Emigrant	Yosemite	96	YOSE1	CA	38.20	119.75	3.2	2.8	2.5	2.1	1.9	1.7	1.5	1.6	1.6	1.9	2.4	2.9
Everglades	Everglades	19	EVER1	FL	25.39	80.68	2.7	2.6	2.6	2.4	2.4	2.7	2.6	2.9	3.0	2.8	2.6	2.7
Fitzpatrick	Bridger	65	BRID1	WY	43.27	109.57	2.5	2.3	2.2	2.1	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.4
Flat Tops	White River	56	WHRI1	CO	39.97	107.25	2.3	2.2	2.0	2.0	2.0	1.8	1.7	1.9	1.9	1.8	2.2	2.2
Galiuro	Chiricahua	39	CHIR1	AZ	32.56	110.32	2.0	1.8	1.5	1.2	1.2	1.1	1.5	1.8	1.6	1.5	1.6	2.1
Gates of the Mountains	Gates of the Mountains	74	GAMO1	MT	46.87	111.81	2.9	2.6	2.4	2.3	2.3	2.3	2.0	1.9	2.1	2.4	2.8	2.8
Gearhart Mountain	Crater Lake	86	CRLA1	OR	42.49	120.85	4.0	3.4	3.1	2.8	2.7	2.5	2.3	2.3	2.4	2.8	3.7	3.8
Gila	Gila Cliffs	42	GICL1	NM	33.22	108.25	2.1	1.9	1.6	1.3	1.4	1.2	2.1	2.0	1.8	1.6	1.8	2.2
Glacier	Glacier	72	GLAC1	MT	48.51	114.00	4.0	3.5	3.2	3.1	3.2	3.4	2.8	2.6	3.2	3.5	3.8	3.9
Glacier Peak	North Cascades	81	NOCA1	WA	48.21	121.04	4.2	3.7	3.4	3.8	2.9	3.2	2.9	3.1	3.3	3.9	4.4	4.4
Goat Rocks	White Pass	79	WHPA1	WA	46.54	121.48	4.3	3.8	3.4	4.2	2.8	3.4	3.0	3.2	3.1	3.8	4.4	4.6
Grand Canyon	Grand Canyon, Hance	48	GRCA2	AZ	35.97	111.98	2.4	2.3	1.9	1.5	1.4	1.2	1.4	1.7	1.6	1.6	1.9	2.3
Grand Teton	Yellowstone	66	YELL2	WY	43.68	110.73	2.6	2.4	2.2	2.1	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.6
Great Gulf	Great Gulf	4	GRGU1	NH	44.31	71.22	2.8	2.6	2.6	2.8	2.9	3.2	3.5	3.8	4.0	3.4	3.1	2.9
Great Sand Dunes	Great Sand Dunes	53	GRSA1	CO	37.73	105.52	2.4	2.3	2.0	1.9	1.9	1.8	1.9	2.3	2.2	1.9	2.4	2.4
Great Smoky Mountains	Great Smoky Mountains	10	GRSM1	TN	35.63	83.94	3.3	3.0	2.9	2.7	3.2	3.9	3.8	4.0	4.2	3.8	3.3	3.4
Guadalupe Mountains	Guadalupe Mountains	32	GUMO1	TX	31.83	104.80	2.0	2.0	1.6	1.5	1.6	1.5	1.9	2.2	2.2	1.8	1.9	2.2
Haleakala	Haleakala	108	HALE1	HI	20.81	156.28	2.7	2.6	2.6	2.5	2.4	2.3	2.5	2.4	2.4	2.5	2.8	2.7
Hawaii Volcanoes	Hawaii Volcanoes	107	HAVO1	HI	19.43	155.27	3.2	2.9	3.0	3.0	3.0	2.9	3.1	3.2	3.2	3.2	3.7	3.2
Hells Canyon	Hells Canyon	77	HECA1	OR	45.34	116.57	3.7	3.1	2.5	2.2	2.1	2.0	1.6	1.6	1.8	2.4	3.5	3.9
Hercules - Glade	Hercules - Glade	28	HEGL1	MO	36.69	92.90	3.2	2.9	2.7	2.7	3.3	3.3	3.3	3.3	3.4	3.1	3.1	3.3
Hoover	Hoover	97	HOOV1	CA	38.14	119.45	3.1	2.8	2.5	2.1	1.9	1.6	1.5	1.5	1.6	1.8	2.3	2.8
Isle Royale	Isle Royale	25	ISLE1	MI	47.99	88.83	3.1	2.5	2.7	2.4	2.2	2.6	3.0	3.2	3.8	2.7	3.3	3.3
James River Face	James River Face	7	JARI1	VA	37.62	79.48	2.8	2.6	2.7	2.4	3.0	3.3	3.4	3.7	3.6	3.2	2.8	3.0
Jarbidge	Jarbidge	68	JARB1	NV	41.89	115.43	3.0	2.6	2.1	2.1	2.2	2.2	1.6	1.4	1.4	1.6	2.4	2.8
John Muir	Kaiser	110	KAIS1	CA	37.39	118.84	2.9	2.6	2.4	2.1	1.9	1.7	1.7	1.7	1.7	1.9	2.2	2.6
Joshua Tree	Joshua Tree	101	JOSH1	CA	34.03	116.18	2.4	2.3	2.2	2.0	2.0	1.9	2.0	2.0	2.0	2.0	1.9	2.0
Joyce Kilmer - Slickrock	Great Smoky Mountains	10	GRSM1	TN	35.43	84.00	3.3	3.1	2.9	2.7	3.3	3.8	4.0	4.2	4.2	3.8	3.3	3.5
Kaiser	Kaiser	110	KAIS1	CA	37.28	119.18	3.0	2.7	2.5	2.1	1.9	1.7	1.6	1.7	1.7	1.9	2.3	2.7
Kalmiopsis	Kalmiopsis	89	KALM1	OR	42.27	123.93	4.5	3.9	3.8	3.5	3.5	3.3	3.2	3.2	3.3	3.6	4.4	4.3
Kings Canyon	Sequoia	98	SEQU1	CA	36.82	118.76	2.8	2.6	2.4	2.1	1.9	1.8	1.7	1.7	1.8	1.9	2.3	2.5
La Garita	Weminuche	55	WEMI1	CO	37.96	106.81	2.3	2.2	1.9	1.8	1.8	1.6	1.7	2.1	2.0	1.8	2.2	2.3
Lassen Volcanic	Lassen Volcanic	90	LAVO1	CA	40.54	121.57	3.8	3.2	2.9	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.1	3.5
Lava Beds	Lava Beds	87	LABE1	CA	41.71	121.34	4.0	3.4	3.1	2.7	2.6	2.4	2.3	2.3	2.4	2.7	3.5	3.8
Linville Gorge	Linville Gorge	13	LIGO1	NC	35.89	81.89	3.3	3.0	3.0	2.7	3.3	3.9	4.1	4.5	4.4	3.7	3.2	3.4
Lostwood	Lostwood	62	LOST1	ND	48.60	102.48	3.0	2.9	2.9	2.3	2.3	2.6	2.7	2.4	2.3	2.4	3.2	3.2
Lye Brook	Lye Brook	3	LYBR1	VT	43.15	73.12	2.7	2.6	2.6	2.6	2.8	3.0	3.3	3.6	3.7	3.3	2.9	2.8
Mammoth Cave	Mammoth Cave	9	MACA1	KY	37.22	86.07	3.4	3.1	2.9	2.6	3.2	3.5	3.7	3.9	3.9	3.4	3.2	3.5
Marble Mountain	Trinity	104	TRIN1	CA	41.52	123.21	4.4	3.8	3.7	3.3	3.4	3.2	3.2	3.2	3.2	3.4	4.1	4.2
Maroon Bells - Snowmass	White River	56	WHRI1	CO	39.15	106.82	2.2	2.1	2.0	2.0	2.1	1.7	1.9	2.2	2.1	1.8	2.1	2.1

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Mazatzal	Ike's Backbone	46	IKBA1	AZ	33.92	111.43	2.1	1.9	1.7	1.3	1.3	1.1	1.5	1.7	1.6	1.5	1.7	2.1
Medicine Lake	Medicine Lake	63	MELA1	MT	48.50	104.29	3.0	2.9	2.9	2.3	2.2	2.5	2.5	2.2	2.2	2.4	3.2	3 2
Mesa Verde	Mesa Verde	54	MEVE1	CO	37.20	108.49	2 5	2.3	1.9	1.5	1.5	1.3	1.6	2.0	1.9	1.7	2.1	2.3
Mingo	Mingo	26	MING1	MO	36.98	90.20	3.3	3.0	2.8	2.6	3.0	3.2	3.3	3.5	3.5	3.1	3.1	3.3
Mission Mountains	Monture	73	MONT1	MT	47.40	113.85	3.6	3.1	2.7	2.5	2.6	2.6	2.3	2.2	2.5	2.9	3.5	3.6
Mokelumne	Bliss	95	BLIS1	CA	38.58	120.03	3.2	2.8	2.4	2.0	1.9	1.6	1.5	1.6	1.7	1.9	2.4	2 9
Moosehorn	Moosehorn	2	MOOS1	ME	45.12	67.26	3.0	2.7	2.7	3.0	3.0	3.1	3.4	3.8	3.9	3.5	3.2	3.2
Mount Adams	White Pass	79	WHPA1	WA	46.19	121.50	4.3	3.8	3.4	4.4	2.9	3.5	3.1	3.3	3.1	3.9	4.5	4.6
Mount Baldy	Mount Baldy	43	BALD1	AZ	34.12	109.57	2.2	2.0	1.7	1.4	1.3	1.2	1.6	1.9	1.7	1.6	1.8	2.2
Mount Hood	Mount Hood	85	MOHO1	OR	45.38	121.69	4.3	3.8	3.5	3.9	3.0	3.2	2.9	3.0	3.1	3.9	4.5	4.6
Mount Jefferson	Three Sisters	84	THSI1	OR	44.55	121.83	4.4	3.9	3.6	3.7	3.1	3.1	2.9	2.9	3.0	3.8	4.6	4 5
Mount Rainier	Mount Rainier	78	MORA1	WA	46.76	122.12	4.4	4.0	3.6	4.7	3.1	3.7	3.3	3.5	3.4	4.1	4.7	4.7
Mount Washington	Three Sisters	84	THSI1	OR	44.30	121.87	4.4	3.9	3.6	3.7	3.1	3.1	3.0	2.9	3.0	3.8	4.6	4.6
Mount Zirkel	Mount Zirkel	58	MOZI1	CO	40.55	106.70	2.2	2.2	2.0	2.1	2.2	1.9	1.7	1.9	2.0	1.9	2.1	2.1
Mountain Lakes	Crater Lake	86	CRLA1	OR	42.34	122.11	4.3	3.6	3.3	3.0	2 9	2.6	2.5	2.5	2.6	3.1	4.1	4 3
North Absaroka	North Absoraka	67	NOAB1	WY	44.77	109.78	2.4	2.3	2.2	2.2	2.1	1.9	1.7	1.6	1.8	2.0	2.4	2.4
North Cascades	North Cascades	81	NOCA1	WA	48.54	121.44	4.1	3.7	3.4	3.7	2.9	3.2	2.9	3.2	3.5	3.9	4.4	4.4
Okefenokee	Okefenokee	16	OKEF1	GA	30.74	82.13	3.5	3.2	3.1	3.0	3.6	3.7	3.7	4.1	4.0	3.8	3.5	3.6
Olympic	Olympic	83	OLYM1	WA	47.32	123.35	4.5	4.1	3.8	4.1	3.2	3.5	3.1	3.5	3.7	4.4	4.8	4 8
Otter Creek	Dolly Sods	8	DOSO1	WV	39.00	79.65	3 0	2.8	2.8	2.6	3.2	3.5	3.7	4.1	4.0	3.3	3.0	3.1
Pasayten	Pasayten	82	PASA1	WA	48.85	120.52	4 2	3.7	3.4	3.7	2.9	3.2	2.9	3 2	3.3	3.9	4.4	4.5
Pecos	Wheeler Peak	35	WHPE1	NM	35.93	105.64	2.3	2.1	1.8	1.7	1.7	1.5	1.8	2.1	2.0	1.7	2.0	2.2
Petrified Forest	Petrified Forest	41	PEFO1	AZ	35.08	109.77	2.4	2.2	1.7	1.4	1.3	1.2	1.5	1.8	1.7	1.6	1.9	2 3
Pine Mountain	Ike's Backbone	46	IKBA1	AZ	34.31	111.80	2 2	2.0	1.7	1.4	1.3	1.1	1.4	1 8	1.6	1.5	1.7	2.1
Pinnacles	Pinnacles	92	PINN1	CA	36.49	121.16	3.2	2.8	2.6	2.4	2.3	2.0	2.0	2.1	2.1	2.3	2.5	2 9
Point Reyes	Point Reyes	91	PORE1	CA	38.12	122.90	3.6	3.3	3.1	2.7	2.5	2.3	2.5	2.6	2.6	2.7	2.9	3.3
Presidential Range - Dry River	Great Gulf	4	GRGU1	NH	44.21	71.35	2.8	2.6	2.6	2.8	3.0	3.4	3.7	4.0	4.3	3.5	3.1	3 0
Rawah	Mount Zirkel	58	MOZI1	CO	40.70	105.94	2.1	2.1	2.0	2.1	2.3	2.0	1.8	2.0	2.0	1.9	2.1	2.0
Red Rock Lakes	Yellowstone	66	YELL2	WY	44.67	111.70	2.7	2.5	2.3	2.1	2.1	1.9	1.7	1.6	1.8	2.1	2.6	2.7
Redwood	Redwood	88	REDW1	CA	41.56	124.08	4.4	3.9	4.6	3.9	4.5	4.7	4.9	4.7	4.3	3.7	3.8	3.4
Rocky Mountain	Rocky Mountain	57	ROMO1	CO	40.28	105.55	1.7	1.9	1.9	2.1	2 3	2.0	1.8	2.0	1.9	1.8	1.8	1.7
Roosevelt Campobello	Moosehorn	2	MOOS1	ME	44.88	66.95	3.0	2.7	2.7	3.0	3.0	3.1	3.4	3.8	3.9	3.5	3.3	3.2
Saguaro	Saguaro	40	SAGU1	AZ	32.25	110.73	1.8	1.6	1.4	1.1	1.1	1.1	1.4	1.8	1.6	1.4	1.6	2.1
Saint Marks	Saint Marks	17	SAMA1	FL	30.12	84.08	3.7	3.4	3.4	3.4	3 5	4.0	4.1	4.4	4.2	3.8	3.7	3 8
Salt Creek	Salt Creek	36	SACR1	NM	33.61	104.37	2.1	1.9	1.5	1.5	1.7	1.6	1.8	2.0	2.1	1.8	1.8	2.1
San Gabriel	San Gabriel	93	SAGA1	CA	34.27	117.94	2.5	2.5	2.4	2.2	2.2	2.1	2.2	2.2	2.2	2.3	2.1	2.2
San Gorgonio	San Gorgonio	99	SAGO1	CA	34.18	116.90	2.7	2.8	2.6	2.3	2.2	1.9	1.8	1.9	1.9	1.9	1.9	2.2
San Jacinto	San Gorgonio	99	SAGO1	CA	33.75	116.65	2.5	2.4	2.4	2.2	2.1	2.0	2.1	2.1	2.1	2.1	2.0	2.1
San Pedro Parks	San Pedro Parks	34	SAPE1	NM	36.11	106.81	2 3	2.1	1.8	1.6	1.6	1.4	1.7	2.0	1.9	1.7	2.1	2.2
San Rafael	San Rafael	94	RAFA1	CA	34.78	119.83	2.8	2.7	2.7	2.4	2.3	2.3	2.5	2.5	2.4	2.5	2.3	2.5

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Sawtooth	Sawtooth	70	SAWT1	ID	44.18	114.93	3.3	2.9	2.3	2.0	2.0	1.8	1.4	1.4	1.5	2.0	2.9	3.3
Scapegoat	Monture	73	MONT1	MT	47.17	112.73	3.2	2.8	2.6	2.4	2.5	2.4	2.1	2.0	2.3	2.6	3.1	3.1
Selway - Bitterroot	Sula	71	SULA1	MT	45.86	114.00	3.5	3.0	2.6	2.3	2.4	2.3	1.9	1.9	2.1	2.6	3.3	3.5
Seney	Seney	22	SENE1	MI	46.26	86.03	3.3	2.8	2.9	2.7	2.6	3.1	3.6	4.0	4.1	3.4	3.6	3.5
Sequoia	Sequoia	98	SEQU1	CA	36.50	118.82	2.5	2.4	2.4	2.2	1.9	1.8	1.7	1.6	1.8	1.9	2.3	2.3
Shenandoah	Shenandoah	6	SHEN1	VA	38.52	78.44	3.1	2.8	2.8	2.5	3.1	3.4	3.5	3.9	3.9	3.2	3.0	3.1
Shining Rock	Shining Rock	11	SHRO1	NC	35.39	82.78	3.3	3.0	2.9	2.7	3.4	3.9	4.1	4.5	4.4	3.8	3.3	3.4
Sierra Ancha	Sierra Ancha	45	SIAN1	AZ	33.82	110.88	2.1	2.0	1.7	1.3	1.3	1.1	1.5	1.8	1.6	1.5	1.7	2.1
Simeonof	Simeonof	105	SIME1	AK	54.92	159.28	4.3	4.1	3.6	3.9	3.9	4.3	5.0	5.2	4.5	3.8	4.0	4.3
Sipsey	Sipsey	21	SIPS1	AL	34.34	87.34	3.4	3.1	2.9	2.8	3.3	3.7	3.9	3.9	3.9	3.6	3.3	3.4
South Warner	Lava Beds	87	LABE1	CA	41.33	120.20	3.6	3.1	2.7	2.4	2.3	2.1	1.9	1.9	2.0	2.3	3.1	3.4
Strawberry Mountain	Starkey	76	STAR1	OR	44.30	118.73	3.9	3.3	2.8	2.9	2.3	2.4	2.0	2.0	1.9	2.6	3.7	4.1
Superstition	Tonto	44	TONT1	AZ	33.63	111.10	2.1	1.9	1.6	1.3	1.3	1.1	1.5	1.7	1.6	1.5	1.7	2.1
Swanquarter	Swanquarter	14	SWAN1	NC	35.31	76.28	2.9	2.7	2.6	2.5	2.9	3.2	3.4	3.5	3.4	3.1	2.8	2.9
Sycamore Canyon	Sycamore Canyon	47	SYCA1	AZ	34.03	116.18	2.4	2.3	2.2	2.0	2.0	1.9	2.0	2.0	2.0	2.0	1.9	2.0
Teton	Yellowstone	66	YELL2	WY	44.09	110.18	2.5	2.4	2.2	2.1	2.1	1.9	1.6	1.5	1.7	2.0	2.4	2.5
Theodore Roosevelt	Theodore Roosevelt	61	THRO1	ND	47.30	104.00	2.9	2.8	2.8	2.3	2.3	2.5	2.4	2.2	2.2	2.3	3.0	3.0
Thousand Lakes	Lassen Volcanic	90	LAVO1	CA	40.70	121.58	3.8	3.2	2.9	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.1	3.5
Three Sisters	Three Sisters	84	THSI1	OR	44.29	122.04	4.5	4.0	3.6	3.7	3.1	3.1	3.0	2.9	3.0	3.8	4.6	4.6
Tuxedni	Tuxedni	103	TUXE1	AK	60.15	152.60	3.5	3.3	2.9	2.7	2.7	2.9	3.6	4.0	3.9	3.5	3.5	3.7
UL Bend	UL Bend	64	ULBE1	MT	47.55	107.87	2.7	2.5	2.5	2.3	2.2	2.2	2.0	1.8	1.9	2.2	2.7	2.7
Upper Buffalo	Upper Buffalo	27	UPBU1	AR	35.83	93.21	3.3	3.0	2.7	2.8	3.4	3.4	3.4	3.4	3.6	3.3	3.2	3.3
Ventana	Pinnacles	92	PINN1	CA	36.22	121.59	3.2	2.9	2.8	2.4	2.3	2.1	2.2	2.3	2.2	2.4	2.5	2.9
Virgin Islands (b)	Virgin Islands	106	VIIS1	VI	18.33	64.79												
Voyageurs	Voyageurs	24	VOYA2	MN	48.59	93.17	2.8	2.4	2.4	2.3	2.3	3.1	2.7	3.0	3.2	2.6	2.9	2.8
Washakie	North Absoraka	67	NOAB1	WY	43.95	109.59	2.5	2.3	2.2	2.1	2.1	1.8	1.6	1.5	1.8	2.0	2.4	2.5
Weminuche	Weminuche	55	WEMI1	CO	37.65	107.80	2.4	2.2	1.9	1.7	1.7	1.5	1.6	2.0	1.9	1.7	2.1	2.3
West Elk	White River	56	WHRI1	CO	38.69	107.19	2.3	2.2	1.9	1.9	1.9	1.7	1.8	2.1	2.0	1.8	2.1	2.2
Wheeler Peak	Wheeler Peak	35	WHPE1	NM	36.57	105.42	2.3	2.2	1.9	1.8	1.8	1.6	1.8	2.2	2.1	1.8	2.2	2.3
White Mountain	White Mountain	37	WHIT1	NM	33.49	105.83	2.1	1.9	1.6	1.5	1.5	1.4	1.8	2.0	2.0	1.7	1.8	2.1
Wichita Mountains	Wichita Mountains	30	WIMO1	OK	34.74	98.59	2.7	2.6	2.4	2.4	3.0	2.7	2.3	2.5	2.9	2.6	2.7	2.8
Wind Cave	Wind Cave	60	WICA1	SD	43.55	103.48	2.5	2.5	2.5	2.5	2.7	2.5	2.3	2.3	2.2	2.2	2.6	2.6
Wolf Island	Okefenokee	16	OKEF1	GA	31.31	81.30	3.4	3.1	3.1	3.0	3.3	3.7	3.7	4.1	4.0	3.7	3.5	3.5
Yellowstone	Yellowstone	66	YELL2	WY	44.55	110.40	2.5	2.4	2.3	2.2	2.2	1.9	1.7	1.6	1.8	2.1	2.5	2.5
Yolla Bolly - Middle Eel	Trinity	104	TRIN1	CA	40.11	122.96	4.0	3.4	3.1	2.8	2.7	2.5	2.4	2.5	2.6	2.7	3.3	3.6
Yosemite	Yosemite	96	YOSE1	CA	37.71	119.70	3.3	3.0	2.8	2.3	2.1	1.8	1.5	1.5	1.5	1.8	2.4	2.8
Zion	Zion	51	ZION1	UT	37.25	113.01	2.7	2.4	2.0	1.6	1.5	1.3	1.2	1.4	1.4	1.6	2.0	2.4

a: No particulate matter sampling or visibility monitoring is conducted in the Bering Sea Wilderness.

b: *f(RH)* values for Virgin Islands National Park were not calculated because of the limited RH data available.

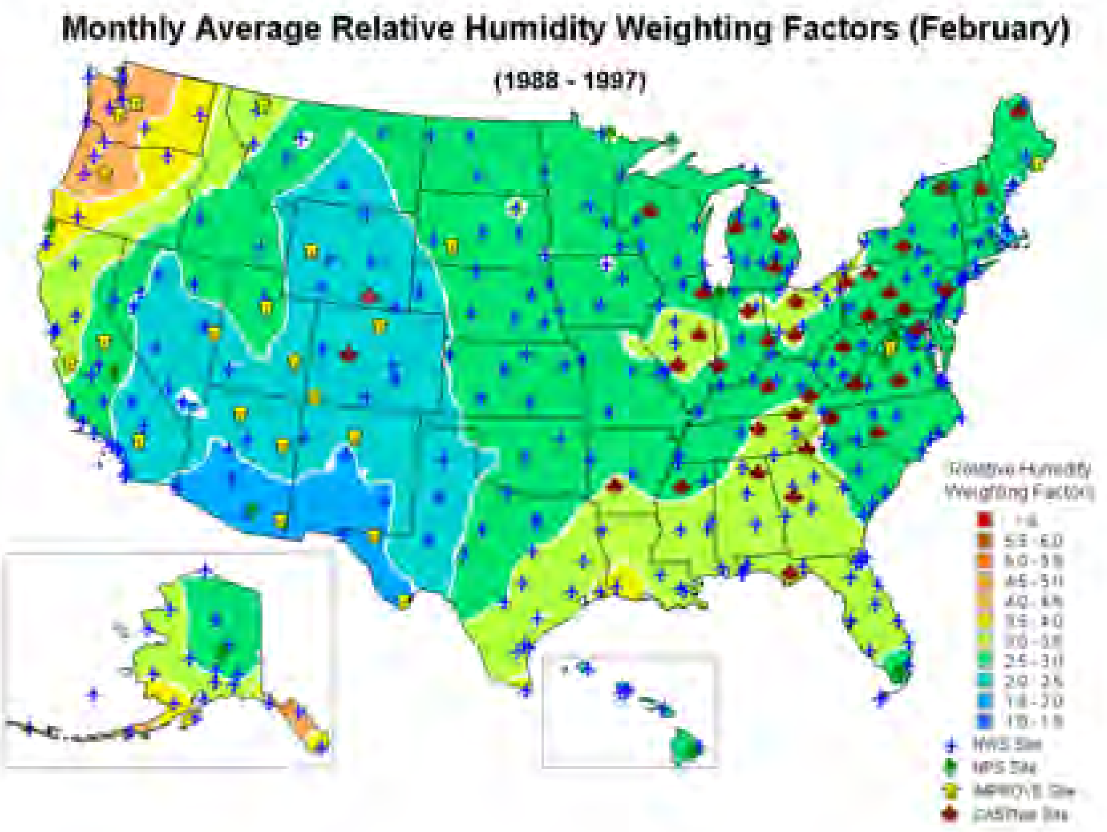

Figure A-1 Monthly Average f(RH) Values for February (all weather stations shown)

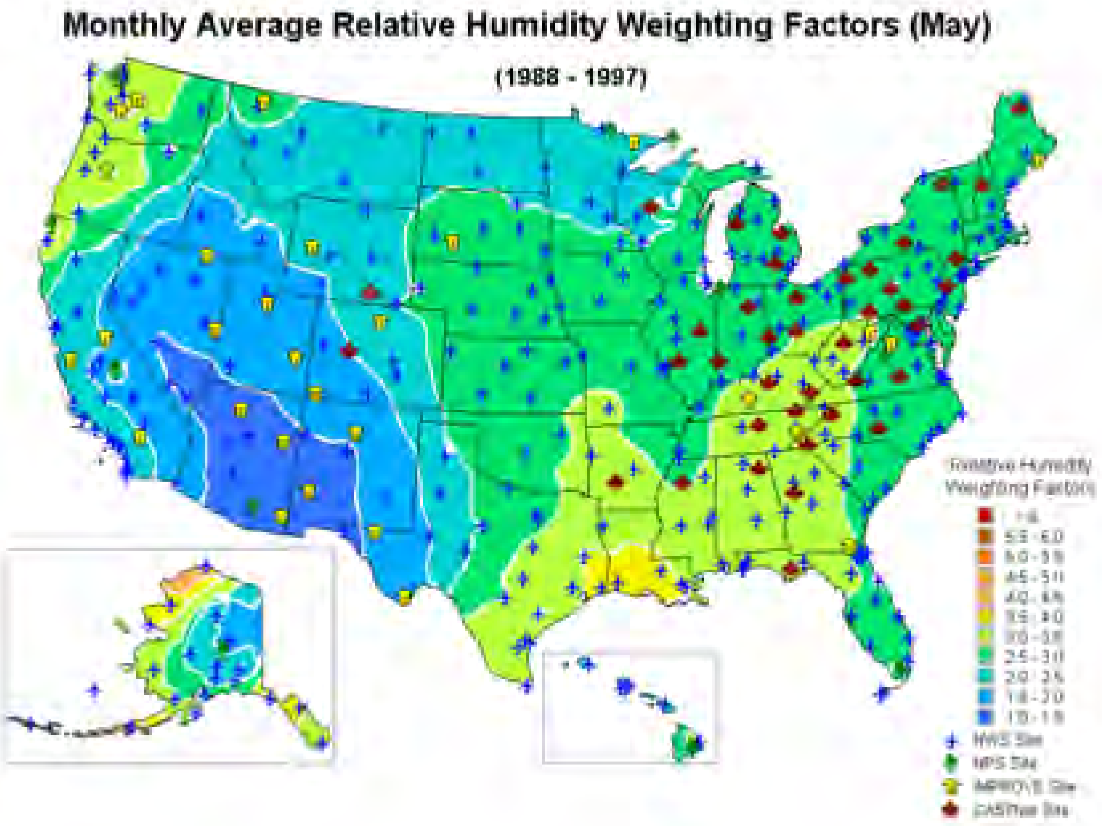

Figure A-2 Monthly Average f(RH) Values for May
(all weather stations shown)

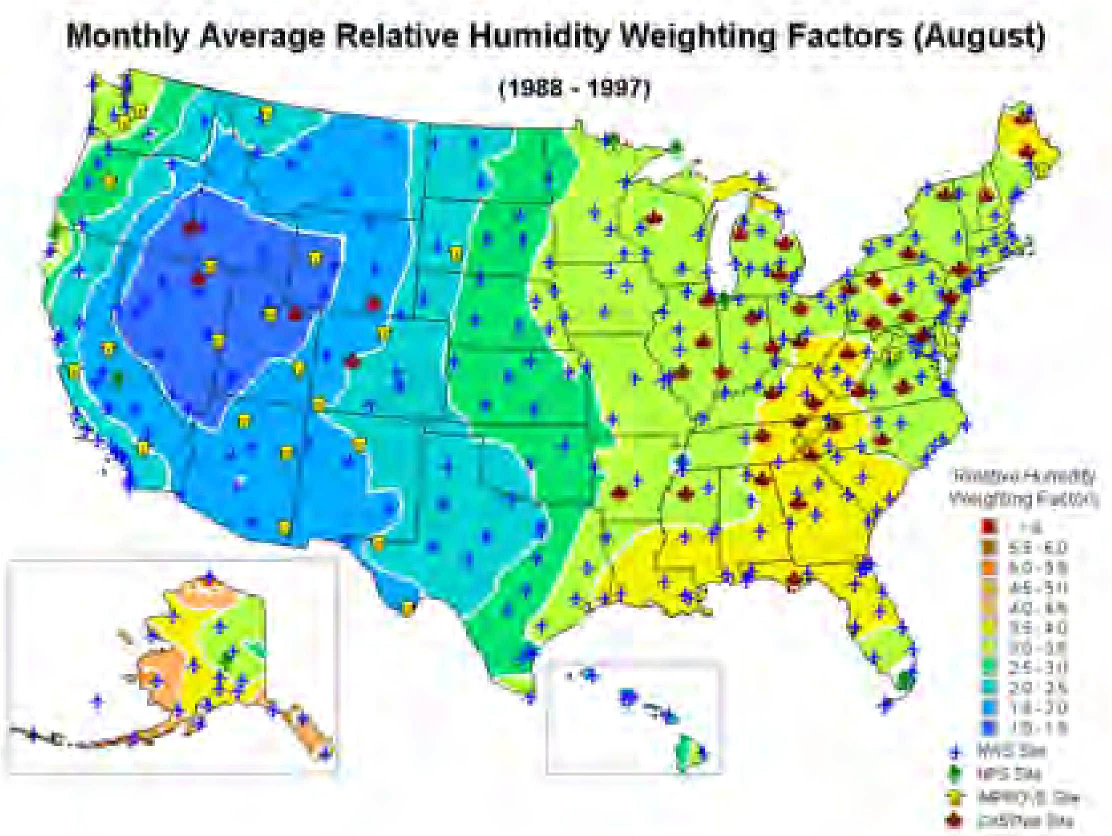

Figure A-3 Monthly Average f(RH) Values for August
(all weather stations shown)

Appendix B

Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [(a)]	Worst Days (dv) [(a)]
Acadia NP	ME	44.35	-68.24	21.40	7.61	3.77	11.45
Agua Tibia Wilderness	CA	33.42	-116.99	15.86	4.61	2.05	7.17
Alpine Lake Wilderness	WA	47.55	-121.16	16.99	5.30	2.74	7.86
Anaconda-Pintler Wilderness	MT	45.95	-113.5	16.03	4.72	2.16	7.28
Arches NP	UT	38.73	-109.58	15.58	4.43	1.87	6.99
Badlands NP	SD	43.81	-102.36	16.06	4.74	2.18	7.30
Bandelier NM	NM	35.79	-106.34	15.62	4.46	1.90	7.02
Bering Sea	AK	60.46	-172.75				
Big Bend NP	TX	29.33	-103.31	15.48	4.37	1.81	6.93
Black Canyon of the Gunnison NM	CO	38.57	-107.75	15.68	4.50	1.94	7.06
Bob Marshall Wilderness	MT	47.68	-113.23	16.17	4.80	2.24	7.36
Bosque del Apache	NM	33.79	-106.85	15.54	4.41	1.85	6.97
Boundary Waters Canoe Area	MN	48.06	-91.43	20.89	7.37	3.53	11.21
Breton	LA	29.87	-88.82	21.57	7.69	3.85	11.53
Bridger Wilderness	WY	42.99	-109.49	15.71	4.52	1.96	7.08
Brigantine	NJ	39.49	-74.39	21.05	7.44	3.60	11.28
Bryce Canyon NP	UT	37.57	-112.17	15.58	4.43	1.87	6.99
Cabinet Mountains Wilderness	MT	48.18	-115.68	16.27	4.87	2.31	7.43
Caney Creek Wilderness	AR	34.41	-94.08	21.14	7.49	3.65	11.33
Canyonlands NP	UT	38.23	-109.91	15.60	4.45	1.89	7.01
Cape Romain	SC	32.99	-79.49	21.22	7.52	3.68	11.36
Capitol Reef NP	UT	38.06	-111.15	15.63	4.47	1.91	7.03
Caribou Wilderness	CA	40.49	-121.21	16.05	4.73	2.17	7.29
Carlsbad Caverns NP	NM	32.12	-104.59	15.61	4.46	1.90	7.02
Chassahowitzka	FL	28.69	-82.66	21.46	7.63	3.79	11.47
Chiricahua NM	AZ	32.01	-109.34	15.47	4.36	1.80	6.92
Chiricahua Wilderness	AZ	31.86	-109.28	15.45	4.35	1.79	6.91
Cohutta Wilderness	GA	34.93	-84.57	21.39	7.60	3.76	11.44
Crater Lake NP	OR	42.92	-122.13	16.74	5.15	2.59	7.71
Craters of the Moon NM	ID	43.39	-113.54	15.80	4.57	2.01	7.13
Cucamonga Wilderness	CA	34.24	-117.59	15.85	4.61	2.05	7.17
Denali Preserve NP	AK	63.31	-151.19	16.27	4.86	2.30	7.42
Desolation Wilderness	CA	38.9	-120.17	15.80	4.57	2.01	7.13
Diamond Peak Wilderness	OR	43.53	-122.1	16.84	5.21	2.65	7.77
Dolly Sods Wilderness	WV	39	-79.37	21.13	7.48	3.64	11.32
Dome Land Wilderness	CA	35.84	-118.23	15.70	4.51	1.95	7.07
Eagle Cap Wilderness	OR	45.22	-117.37	16.12	4.78	2.22	7.34

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [(a)]	Worst Days (dv) [(a)]
Eagles Nest Wilderness	CO	39.67	-106.29	15.72	4.52	1.96	7.08
Emigrant Wilderness	CA	38.18	-119.77	15.81	4.58	2.02	7.14
Everglades NP	FL	25.35	-80.98	20.77	7.31	3.47	11.15
Fitzpatrick Wilderness	WY	43.24	-109.6	15.73	4.53	1.97	7.09
Flat Tops Wilderness	CO	39.95	-107.3	15.70	4.51	1.95	7.07
Galiuro Wilderness	AZ	32.6	-110.39	15.40	4.32	1.76	6.88
Gates of the Mountains Wilderness	MT	46.86	-111.82	15.93	4.66	2.10	7.22
Gearhart Mountain Wilderness	OR	42.51	-120.86	16.33	4.90	2.34	7.46
Gila Wilderness	NM	33.21	-108.47	15.51	4.39	1.83	6.95
Glacier NP	MT	48.64	-113.84	16.48	5.00	2.44	7.56
Glacier Peak Wilderness	WA	48.21	-121	16.88	5.24	2.68	7.80
Goat Rocks Wilderness	WA	46.52	-121.47	16.93	5.26	2.70	7.82
Grand Canyon NP	AZ	36.3	-112.79	15.51	4.39	1.83	6.95
Grand Teton NP	WY	43.82	-110.71	15.74	4.53	1.97	7.09
Great Gulf Wilderness	NH	44.3	-71.28	21.10	7.47	3.63	11.31
Great Sand Dunes NM	CO	37.77	-105.57	15.74	4.54	1.98	7.10
Great Smoky Mountains NP	TN	35.6	-83.52	21.39	7.60	3.76	11.44
Guadalupe Mountains NP	TX	31.91	-104.85	15.64	4.47	1.91	7.03
Haleakala NP	HI	20.71	-156.16	16.02	4.71	2.15	7.27
Hawaii Volcanoes NP	HI	19.41	-155.34	16.33	4.91	2.35	7.47
Hells Canyon Wilderness	OR	45.54	-116.59	16.09	4.76	2.20	7.32
Hercules-Glades Wilderness	MO	36.68	-92.9	21.03	7.43	3.59	11.27
Hoover Wilderness	CA	38.11	-119.37	15.78	4.56	2.00	7.12
Isle Royale NP	MI	48.01	-88.83	20.91	7.38	3.54	11.22
James River Face Wilderness	VA	37.59	-79.44	20.96	7.40	3.56	11.24
Jarbidge Wilderness	NV	41.77	-115.35	15.75	4.54	1.98	7.10
John Muir Wilderness	CA	36.97	-118.88	15.80	4.58	2.02	7.14
Joshua Tree NM	CA	33.92	-115.88	15.72	4.52	1.96	7.08
Joyce-Kilmer-Slickrock Wilderness	TN	35.44	-83.99	21.40	7.61	3.77	11.45
Kaiser Wilderness	CA	37.28	-119.17	15.80	4.57	2.01	7.13
Kalmiopsis Wilderness	OR	42.26	-123.92	16.74	5.15	2.59	7.71
Kings Canyon NP	CA	36.92	-118.61	15.79	4.57	2.01	7.13
La Garita Wilderness	CO	37.95	-106.83	15.69	4.50	1.94	7.06
Lassen Volcanic NP	CA	40.49	-121.41	16.08	4.75	2.19	7.31
Lava Beds NM	CA	41.76	-121.52	16.37	4.93	2.37	7.49
Linville Gorge Wilderness	NC	35.88	-81.9	21.36	7.59	3.75	11.43
Lostwood	ND	48.59	-102.46	16.11	4.77	2.21	7.33

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) (a)	Worst Days (dv) (a)
Lye Brook Wilderness	VT	43.13	-73.02	20.99	7.41	3.57	11.25
Mammoth Cave NP	KY	37.2	-86.15	21.58	7.69	3.85	11.53
Marble Mountain Wilderness	CA	41.51	-123.21	16.65	5.10	2.54	7.66
Maroon Bells-Snowmass Wilderness	CO	39.1	-107.02	15.70	4.51	1.95	7.07
Mazatzal Wilderness	AZ	34.13	-111.56	15.44	4.35	1.79	6.91
Medicine Lake	MT	48.49	-104.35	16.07	4.74	2.18	7.30
Mesa Verde NP	CO	37.25	-108.45	15.73	4.53	1.97	7.09
Minarets Wilderness	CA	37.74	-119.19	15.78	4.56	2.00	7.12
Mingo	MO	37	-90.19	21.03	7.43	3.59	11.27
Mission Mountains Wilderness	MT	47.48	-113.87	16.21	4.83	2.27	7.39
Mokelumne Wilderness	CA	38.57	-120.06	15.80	4.58	2.02	7.14
Moosehorn	ME	45.09	-67.29	21.22	7.52	3.68	11.36
Mount Adams Wilderness	WA	46.2	-121.49	16.86	5.22	2.66	7.78
Mount Baldy Wilderness	AZ	33.95	-109.54	15.51	4.39	1.83	6.95
Mount Hood Wilderness	OR	45.37	-121.73	16.83	5.21	2.65	7.77
Mount Jefferson Wilderness	OR	44.61	-121.84	16.91	5.25	2.69	7.81
Mount Rainier NP	WA	46.86	-121.72	17.05	5.34	2.78	7.90
Mount Washington Wilderness	OR	44.3	-121.88	17.03	5.33	2.77	7.89
Mount Zirkel Wilderness	CO	40.75	-106.68	15.71	4.52	1.96	7.08
Mountain Lakes Wilderness	OR	42.33	-122.11	16.50	5.01	2.45	7.57
North Absaroka Wilderness	WY	44.74	-109.8	15.74	4.53	1.97	7.09
North Cascades NP	WA	48.83	-121.35	16.86	5.22	2.66	7.78
Okefenokee	GA	30.82	-82.33	21.41	7.61	3.77	11.45
Olympic NP	WA	47.77	-123.74	17.02	5.32	2.76	7.88
Otter Creek Wilderness	WV	38.99	-79.65	21.14	7.49	3.65	11.33
Pasayten Wilderness	WA	48.89	-120.44	16.84	5.21	2.65	7.77
Pecos Wilderness	NM	35.9	-105.62	15.65	4.48	1.92	7.04
Petrified Forest NP	AZ	34.99	-109.79	15.54	4.41	1.85	6.97
Pine Mountain Wilderness	AZ	34.31	-111.8	15.47	4.36	1.80	6.92
Pinnacles NM	CA	36.48	-121.19	16.12	4.78	2.22	7.34
Point Reyes NS	CA	38.06	-122.9	16.20	4.83	2.27	7.39
Presidential Range-Dry River Wilderness	NH	44.2	-71.34	21.15	7.49	3.65	11.33
Rainbow Lake Wilderness	WI	46.42	-91.31	20.99	7.42	3.58	11.26
Rawah Wilderness	CO	40.69	-105.95	15.72	4.52	1.96	7.08
Red Rock Lakes	MT	44.64	-111.78	15.81	4.58	2.02	7.14
Redwood NP	CA	41.44	-124.03	16.90	5.25	2.69	7.81
Rocky Mountain NP	CO	40.35	-105.7	15.67	4.49	1.93	7.05

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Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [(a)]	Worst Days (dv) [(a)]
Roosevelt Campobello International Park	ME	44.85	-66.94	21.22	7.52	3.68	11.36
Saguaro NM	AZ	32.17	-110.61	15.35	4.28	1.72	6.84
Salt Creek	NM	33.6	-104.41	15.58	4.43	1.87	6.99
San Gabriel Wilderness	CA	34.27	-117.94	15.86	4.61	2.05	7.17
San Gorgonio Wilderness	CA	34.12	-116.84	15.74	4.54	1.98	7.10
San Jacinto Wilderness	CA	33.75	-116.64	15.78	4.56	2.00	7.12
San Pedro Parks Wilderness	NM	36.11	-106.81	15.63	4.47	1.91	7.03
San Rafael Wilderness	CA	34.76	-119.81	16.03	4.72	2.16	7.28
Sawtooth Wilderness	ID	43.99	-115.06	15.82	4.59	2.03	7.15
Scapegoat Wilderness	MT	47.16	-112.74	16.05	4.73	2.17	7.29
Selway-Bitterroot Wilderness	ID	46.12	-114.86	16.09	4.76	2.20	7.32
Seney	MI	46.25	-86.09	21.23	7.53	3.69	11.37
Sequoia NP	CA	36.51	-118.56	15.79	4.57	2.01	7.13
Shenandoah NP	VA	38.47	-78.49	20.98	7.41	3.57	11.25
Shining Rock Wilderness	NC	35.38	-82.85	21.40	7.61	3.77	11.45
Sierra Ancha Wilderness	AZ	33.85	-110.9	15.46	4.36	1.80	6.92
Simeonof	AK	54.91	-159.28	17.21	5.43	2.87	7.99
Sipsey Wilderness	AL	34.32	-87.44	21.28	7.55	3.71	11.39
South Warner Wilderness	CA	41.31	-120.2	16.09	4.76	2.20	7.32
St. Marks	FL	30.11	-84.15	21.54	7.67	3.83	11.51
Strawberry Mountain Wilderness	OR	44.29	-118.74	16.37	4.93	2.37	7.49
Superstition Wilderness	AZ	33.5	-111.27	15.40	4.32	1.76	6.88
Swanquarter	NC	35.39	-76.39	20.91	7.38	3.54	11.22
Sycamore Canyon Wilderness	AZ	35.01	-112.09	15.53	4.40	1.84	6.96
Teton Wilderness	WY	44.04	-110.17	15.74	4.53	1.97	7.09
Theodore Roosevelt NP	ND	46.96	-103.46	16.08	4.75	2.19	7.31
Thousand Lakes Wilderness	CA	40.7	-121.58	16.10	4.76	2.20	7.32
Three Sisters Wilderness	OR	44.04	-121.91	17.01	5.31	2.75	7.87
Tuxedni	AK	60.14	-152.61	16.58	5.06	2.50	7.62
UL Bend	MT	47.54	-107.89	15.87	4.62	2.06	7.18
Upper Buffalo Wilderness	AR	36.17	-92.41	21.04	7.44	3.60	11.28
Ventana Wilderness	CA	36.21	-121.6	16.09	4.76	2.20	7.32
Virgin Islands NP **(b)**	VI	18.35	-64.74				
Voyageurs NP	MN	48.47	-92.8	20.64	7.25	3.41	11.09
Washakie Wilderness	WY	44.1	-109.57	15.73	4.53	1.97	7.09
Weminuche Wilderness	CO	37.61	-107.25	15.68	4.50	1.94	7.06
West Elk Wilderness	CO	38.75	-107.21	15.71	4.51	1.95	7.07

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Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) (a)	Worst Days (dv) (a)
Wheeler Peak Wilderness	NM	36.57	-105.4	15.70	4.51	1.95	7.07
White Mountain Wilderness	NM	33.48	-105.85	15.56	4.42	1.86	6.98
Wichita Mountains	OK	34.75	-98.65	20.60	7.23	3.39	11.07
Wind Cave NP	SD	43.58	-103.47	15.97	4.68	2.12	7.24
Wolf Island	GA	31.33	-81.3	21.33	7.58	3.74	11.42
Yellowstone NP	WY	44.63	-110.51	15.77	4.56	2.00	7.12
Yolla Bolly Middle Eel Wilderness	CA	40.09	-122.96	16.25	4.85	2.29	7.41
Yosemite NP	CA	37.85	-119.54	15.81	4.58	2.02	7.14
Zion NP	UT	37.32	-113.04	15.56	4.42	1.86	6.98

(a) Values for the best and worst days are estimated from a statistical approach described in Section 2.6 of this document.
(b) *f(RH)* values for Virgin Islands National Park were not calculated because of the limited RH data available. As such no estimates for Natural Visibility Conditions are presented at this time.

TECHNICAL REPORT DATA

(Please read Instructions on reverse before completing)

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EPA-454/B-03-005

2

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15 SUPPLEMENTARY NOTES

16 ABSTRACT

The purpose of this document is to provide guidance to the States in implementing the regional haze program under the Clean Air Act. As part of the program, States will develop goals and implement strategies for improving visibility in each mandatory Federal Class I area. Estimates of natural visibility conditions are needed by the States for the goal development process. This guidance document describes "default"[16] and "refined" approaches for estimating natural conditions. EPA believes that natural conditions estimates developed using the default approach will be adequate to satisfy the requirements of the regional haze rule for the initial SIP submittals due no later than 2008. This document provides guidance to EPA Regional, State, and Tribal air quality management authorities and the general public, on how EPA intends to exercise its discretion in implementing Clean Air Act provisions and EPA regulations, concerning the estimation of natural conditions under the regional haze program.

17 KEY WORDS AND DOCUMENT ANALYSIS

a DESCRIPTORS	b IDENTIFIERS/OPEN ENDED TERMS	c COSATI Field/Group
Regional Haze, Haze Index	Air Pollution control	

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Postal information in this section where appropriate.

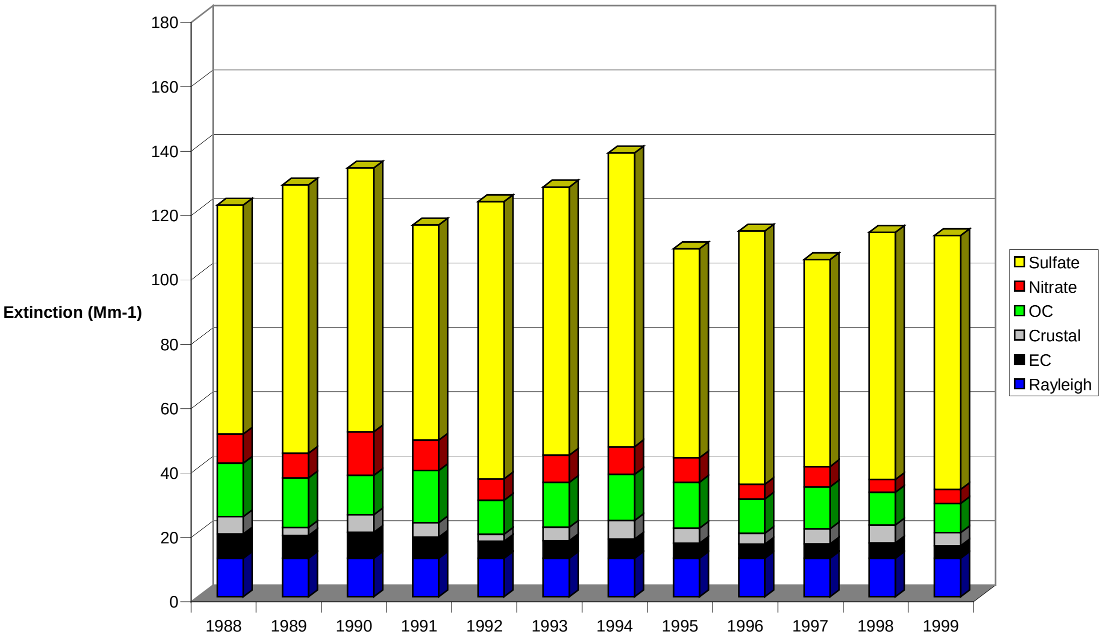
Technical Memorandum #1

Updated Visibility Statistics for the MANE-VU Region

Prepared by Northeast States for
Coordinated Air Use Management
(NESCAUM)

For the Mid-Atlantic/Northeast Visibility
Union (MANE-VU) Regional Planning
Organization

February 15, 2002



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Technical Memorandum #1

Updated Visibility Statistics for the MANE-VU Region

February 15, 2002

Submitted to the United States Environmental Protection Agency, Region III in partial
fulfillment of requirements for EPA grant X-983384-01-0 to the
Ozone Transport Commission

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Table of Contents

Executive Summary

Under the U.S. Environmental Protection Agency's (USEPA) 1999 regional haze rule, states and tribes are required to submit implementation plans which must include calculations of current and estimated natural visibility conditions. Recent monitoring data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) network has been used to examine visibility conditions in the Mid-Atlantic/Northeast Visibility Union (MANE-VU) region. These results suggest that across the MANE-VU region, visibility impairment on the 20 percent of days with the worst visibility in 1999 was reduced by approximately 2 dv relative to conditions in 1997 with the worst visibility conditions occurring further south and west. Further research is required to determine the cause of this improvement; however, meteorological conditions may have played a role. A slight decrease in nitrate composition appears to have occurred between 1995 and 2000, however, no substantive reductions in sulfate or organic material are apparent on the twenty percent worst visibility days during this same time period.

Recent guidance issued by USEPA for calculating visibility conditions suggests the use of climatological monthly mean values of the relative humidity adjustment factor to account for differences in scattering properties of fine particulate with increased relative humidity. An examination of relative humidity adjustment factor averaging time suggests that use of annual or monthly mean values may understate visibility conditions calculated using daily average relative humidity data where available. Comparison with optical data confirms that measured visibility conditions (i.e. transmissometer and nephelometer data) may be substantially different from those conditions obtained through USEPA recommended procedures. Further study is required to determine the impact these differences are likely to have on calculated rates of progress.

I. Introduction

States and tribes must submit implementation plans by December 31, 2008 outlining control measures needed over the subsequent ten years (2009-2018) in order to improve visibility conditions in Federal Class I areas within and near the MANE-VU region in compliance with the Environmental Protection Agency's (USEPA) regional haze rule. These plans must include calculations of baseline[1] and estimated natural visibility conditions. These plans must also estimate the necessary rate of progress for the 10-year compliance period needed to achieve the overall goal of natural visibility conditions by 2064. This document provides a survey of speciated fine particle and monitoring data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) program and how it can be used in this process. This work builds upon a previous NESCAUM report (NESCAUM, 2001a) and is intended to update and expand upon the technical discussion presented in that document. New figures are presented which describe the nature and extent of visibility impairment in the region. Data used to generate each figure are presented in tabular form in Appendix A.

Two documents have recently been drafted by USEPA in order to guide states and tribes in performing reasonable progress and natural visibility calculations (USEPA 2001a, 2001b). While the methodology for calculating reconstructed light extinction used in this document is consistent with the approach taken in these guidance documents, NESCAUM has not rigorously applied the guidance recommendations for the substitution of missing values. When the proposed guidance documents are finalized, those aspects of the calculations presented here that differ from the guidance should be harmonized to provide a consistent assessment of current visibility conditions and trends in the MANE-VU region.

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[1] Calculations of baseline conditions are based on monitored data from the years 2000 to 2004.

II. Data Sources and Methodologies

Data from the IMPROVE program represent a crucial input to state and tribal planning efforts under the 1999 regional haze rule. The National Park Service manages the IMPROVE program with the support of several contractors who perform specific data collection and analysis functions. These contractors include the University of California at Davis (site selection, filter management, gravimetric and elemental analyses and database management), the Desert Research Institute (elemental and organic carbon analyses), the Research Triangle Institute (ion analyses), Atmospheric Resource Specialists, Inc. (optical, scene, and meteorological data collection), and the Cooperative Institute for Research in the Atmosphere (data analysis and website support).

The IMPROVE web site provides speciated data for all sampling days at IMPROVE monitors.[2] Total particle light extinction can be calculated using this information and the methodology described below. Table 1 lists the particle species, formulae and assumptions used by IMPROVE to calculate particle concentrations. Ambient concentrations are in turn used to calculate reconstructed particle light extinction coefficients. The bracketed symbols in the second column of Table 1 correspond to species concentrations and to the labeling conventions used in the IMPROVE database. The labeling convention is:

[S] = Elemental sulfur
[NO3] = Nitrate
[EC#] = Detailed elemental carbon species measured by thermal optical reflectance (TOR) with three bins (# = 1,2,3)
[OC#] & [OP] = Detailed TOR organic species with bins (# = 1,2,3,4)
[AL] = Aluminum
[SI] = Silicon
[CA] = Calcium
[FE] = Iron
[TI] = Titanium
[MT] = Total mass (PM_{10})
[MF] = Fine mass ($PM_{2.5}$)

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[2] IMPROVE data are available via an ftp link located at the web address http://alta_vista.cira.colostate.edu/. The website is part of a cooperative program on visibility in Class I areas between the National Park Service Air Resources Division and the Cooperative Institute for Research in the Atmosphere (CIRA) at Colorado State University in Ft. Collins.

Table 1: Formulae and assumptions used with IMPROVE sampling measurements to derive reconstructed particle light extinction (adapted from Sisler and Malm, 2000).

Species	Formula	Assumptions
SULFATE	4.125[S]	All elemental S is from sulfate. All sulfate is from ammonium sulfate.
NITRATE	1.29[NO3]	Denuder efficiency is close to 100%. All nitrate is from ammonium nitrate.
LAC (Light absorbing carbon)	[EC1] + [EC2] + [EC3] – [OP]	All high temperature carbon is elemental.
OMC (Organic mass from carbon)	1.4{[OC1] + [OC2] + [OC3] + [OC4] + [OP]}	Average organic molecule is 71% carbon.
SOIL (Fine Soil)	2.2[AL] + 2.49[SI] + 1.63[CA] + 2.42[FE] + 1.94[TI]	[Soil K] = 0.6[Fe]. FeO and Fe_2O are equally abundant. A factor of 1.16 is used for MgO, Na_2O, H_2O, CO_2.
RCFM (Reconstructed fine mass)	[SULFATE] + [NITRATE] + [LAC] + [OMC] + [SOIL]	Represents dry ambient fine aerosol mass for continental sites.
CM (Coarse Mass)	[MT] – [MF]	Consists only of insoluble soil particles.

Total light extinction is a function of the individual light absorption and light scattering properties of particles present in the atmosphere. This total is frequently expressed as a light extinction coefficient (b_{ext}) in units of inverse length (such as Mm^{-1}). In simple terms, the light extinction coefficient is a measure of the proportion of light extinguished per unit of distance traveled through the atmosphere. The light extinction coefficient, b_{ext}, can be measured directly with a transmissometer or determined empirically by "reconstructing" extinction as the sum of the scattering and absorption coefficients of the relevant particle constituents, as indicated by the following equation.:[3,4]

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[3] Absorption by nitrogen dioxide gas is not generally significant on a regional scale, though it can play a role in coherent pollution plumes (FLAG, 2000). Hence the discussion in this chapter considers elemental carbon as the only contributor to atmospheric light absorption.

$b_{ext} = b_{SO4} + b_{NO3} + b_{OrgC} + b_{Soil} + b_{Coarse} + b_{ElemC} + b_{Ray}$

Note that this equation includes Rayleigh scattering, b_{Ray}, which is a measure of scattering due to air molecules. The Federal Land Managers' Air Quality Related Values Workgroup (FLAG) uses a Rayleigh scattering value of 10 Mm^{-1} for the entire U.S. (FLAG, 2000). This value corresponds to Rayleigh conditions at about 1800 meters above sea level (Sisler and Malm, 2000). However, Rayleigh scattering varies with altitude and at sea level is estimated to be about 12 Mm^{-1} (Trijonis et al., 1990). To avoid understating "natural" background visibility impairment at coastal sites (which could result in setting unrealistic goals for haze reduction efforts), the analysis conducted here assumes a Rayleigh coefficient of 12 Mm^{-1} for the Acadia, Brigantine, Moosehorn, and Roosevelt Campobello Class I areas as well as the Washington D.C. and the James River Face IMPROVE sites. All of these sites have a mean altitude below 300 meters. This assumption reduces calculated background extinction levels by 2 Mm^{-1} but leads to a change of only 0.3 dv in estimated natural background conditions on the deciview scale.[5]

The calculation of extinction coefficients for each individual chemical species can be described by the following equations (FLAG, 2000):

$b_{SO4} = 3[(NH_4)_2SO_4]f(RH)$ [6]
$b_{NO3} = 3[NH_4NO_3]f(RH)$
$b_{OrgC} = 4[OrgC]$
$b_{Soil} = 1[Soil]$
$b_{Coarse} = 0.6[Coarse]$
$b_{ElemC} = 10[ElemC]$.

The bracketed quantities represent ambient air concentrations expressed in micrograms per cubic meter ($\mu g/m^3$). The numeric coefficients represent "dry" scattering efficiencies[7] (m^2/g), while the relative humidity adjustment factor f(RH) accounts for the hygroscopic properties of sulfate and nitrate (i.e., their tendency to absorb water in the atmosphere). As relative humidity increases this factor becomes larger, which in turn produces a higher coefficient of light extinction for the hygroscopic particles. Provided concentrations and humidity levels are known, the light extinction coefficients for individual particle constituents can be calculated and summed to estimate the overall light extinction coefficient, b_{ext}.

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[4] Particles in the atmosphere may exist as an internal mixture of several chemical species. IMPROVE assumes that the contribution of each particle constituent can be determined separately and summed to determine total light extinction.

[5] This assumption is in contrast to the recent USEPA guidance on this point which recommends using 10 Mm^{-1} consistently at all Class I areas, regardless of altitude (USEPA, 2001a).

[6] IMPROVE assumes that all sulfate is in the form ammonium sulfate ($(NH_4)_2SO_4$) and that all nitrate is in the form ammonium nitrate (NH_4NO_3). Other forms of these species exist in nature as detailed in Section D of this chapter. These differing forms may have different scattering efficiencies and relative humidity adjustment factors.

[7] Dry scattering efficiencies were determined for light at 550 nm (0.55 µm; green). There may be discrepancies between this value and those determined by integrating over the entire visible spectrum (400-700 nm).

It should be noted that a number of uncertainties are embedded in these calculations; hence, reconstruction of light extinction will not be accurate for every sample.[8] For example, the equations reflect simplified assumptions about the role of relative humidity and may not adequately account for the non-linear relationship between humidity and particle growth rate. Moreover, the relative humidity values traditionally used by IMPROVE represent an average over large geographic areas and long periods of time. Ideally, relative humidity should be recorded and stored with each concentration measurement so that an appropriate factor can be calculated for each observation. Second, different humidity adjustment factors should be used for the sulfate and nitrate fraction of aerosol particles given differences in the growth rates for these two constituents with increasing relative humidity. Third, the above equations assume that organic carbons are non-hygroscopic and do not require a relative humidity adjustment. In many instances little information is available about the specific constituents of secondary organic aerosol particles and of their potential affinity for water. Whether or not a relative humidity adjustment factor should be applied to the organic fraction is therefore an issue of current debate (Saxena et al., 1995). Finally, the IMPROVE calculations make an assumption that the particles are externally mixed as opposed to the more likely case that each particle is a homogenous (internal) mixture of the individual components. This difference will affect the physical properties of the particle and in turn how they impact visibility. The sensitivity of reconstructed light extinction to each of these assumptions is an area that warrants further investigation.[9] It should be noted that the IMPROVE program has taken efforts to quantify the precision of the techniques used for their calculations and has deemed it sufficient for the IMPROVE program objectives.

The recent guidance documents issued by USEPA (in draft form) discuss some of the uncertainty present in reconstructed light extinction, but do not resolve the issue by performing a detailed sensitivity analysis for each assumption. Section V of this report describes some comparisons of reconstructed light extinction with measured light extinction and attempts to quantify the discrepancy between the two techniques and thus provide a measure of the overall uncertainty.

The regional haze rule requires that visibility conditions be measured in deciview, a metric that is approximately linear with human perception of visibility impairment. The deciview is related to atmospheric extinction through the following relationship:

$$dv = 10 \ln(b_{ext}/10).$$

Extinction is used in this memorandum to explore the contribution of individual component of fine particulate to overall visibility impairment. The deciview is used to examine trends in visibility conditions.

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[8] In fact, reconstructed light extinction is not expected to be accurate for every sample as it was designed to provide a consistent and replicable process for approximating light extinction based on observed relationships.

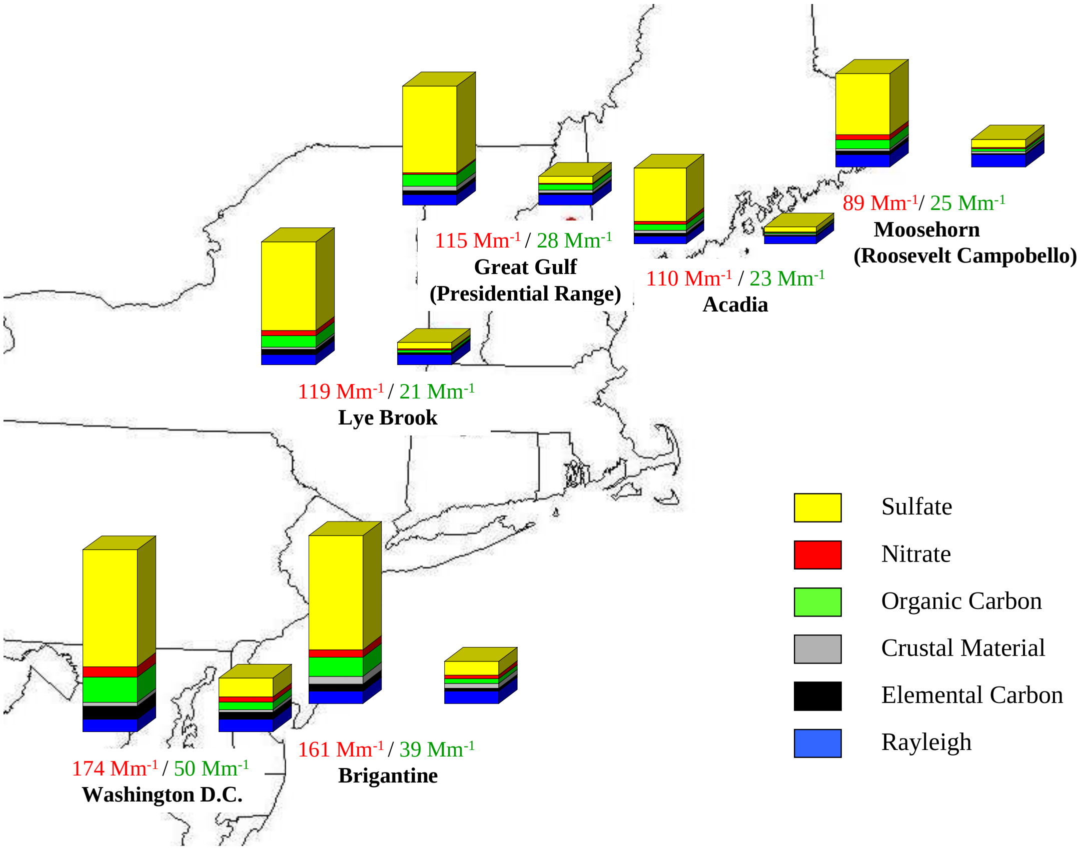
[9] The sensitivity of reconstructed light extinction to relative humidity adjustment factor averaging time is explored in Section IV. The FLAG (FLAG, 2000) has suggested that annually-averaged adjustment factors are adequate for screening analyses; however, the recent USEPA guidance (USEPA, 2001a) has recommended monthly average factors be used for SIP work.

III. Visibility Across the Northeastern U.S. –1999

A. MANE-VU Class I Areas

The regional haze rule calls for a steady improvement of visibility on the 20 percent of days with the worst visibility and the prevention of deterioration in visibility on the 20 percent of days with the best visibility at Federal Class I areas across the country. In 1999, visibility experienced at MANE-VU Class I areas was somewhat better than that which has been documented previously for 1997 (NESCAUM, 2001a). As Figure 1 shows, the 20 percent of days with the worst visibility[10] (left bars; based on calculations of reconstructed light extinction) range from 89 to 174 Mm^{-1} of total light

Figure 1: Speciated contribution to total atmospheric light extinction in or near Class I Areas in the Northeast and Mid-Atlantic states on 20 percent of days with the worst (left bar) and best (right bar) visibility conditions during 1999.



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[10] The terms “worst” or “best” visibility as well as “20 percent worst” or “20 percent best” visibility conditions are defined throughout this report as the simple average of the upper or lower 20 percentile of a cumulative frequency distribution of reconstructed light extinction for days in which all particle species were successfully measured, respectively.

extinction (particle light extinction plus Rayleigh scattering).[11] This corresponds to 22-29 dv and is approximately 2 dv lower than visibility conditions on the worst days in 1997. Visibility impairment is not, however, uniform across the region, with the worst visibility conditions occurring further south and west.

The majority of this visibility impairment can be attributed to sulfate aerosol, which was responsible for over two-thirds of the extinction on the days with the worst twenty percent visibility at most sites. Organic Carbon (OC) is formed from the byproducts of literally hundreds of precursor organic molecules including Volatile Organic Compounds (VOCs) and biogenically emitted species. After sulfate, organic carbon is responsible for the greatest atmospheric extinction on the days with the worst and best visibility days. Nitrate, elemental carbon (or soot) and crustal material (i.e. dust and soil) are responsible for the remaining particle extinction. Rayleigh scattering, due to natural scattering of air molecules, is shown in blue.

Substantially lower levels of visibility impairment are present on the 20 percent of days with the best visibility conditions (see right bars in Figure 1) relative to the worst days. However, it should be noted that some areas (especially those further south and west) still have significant visibility impairment relative to natural conditions, estimated to be approximately 21-24 Mm^{-1} or 8-9 dv (NESCAUM, 2001a).

B. Nearby Areas

Areas just to the south of the MANE-VU region also saw improved visibility conditions in 1999 over what has been reported previously for 1997. Figure 2 shows average reconstructed light extinction for the 20 percent of days with the worst and best visibility conditions at IMPROVE monitors at Class I areas in Virginia and West Virginia. These values represent, on average, a 3 dv improvement in the worst 20 percent of visibility conditions in 1999 relative to 1997 values. Similar to the MANE-VU Class I areas, an analysis of the 2000 data will be required to know whether or not the trend has continued.

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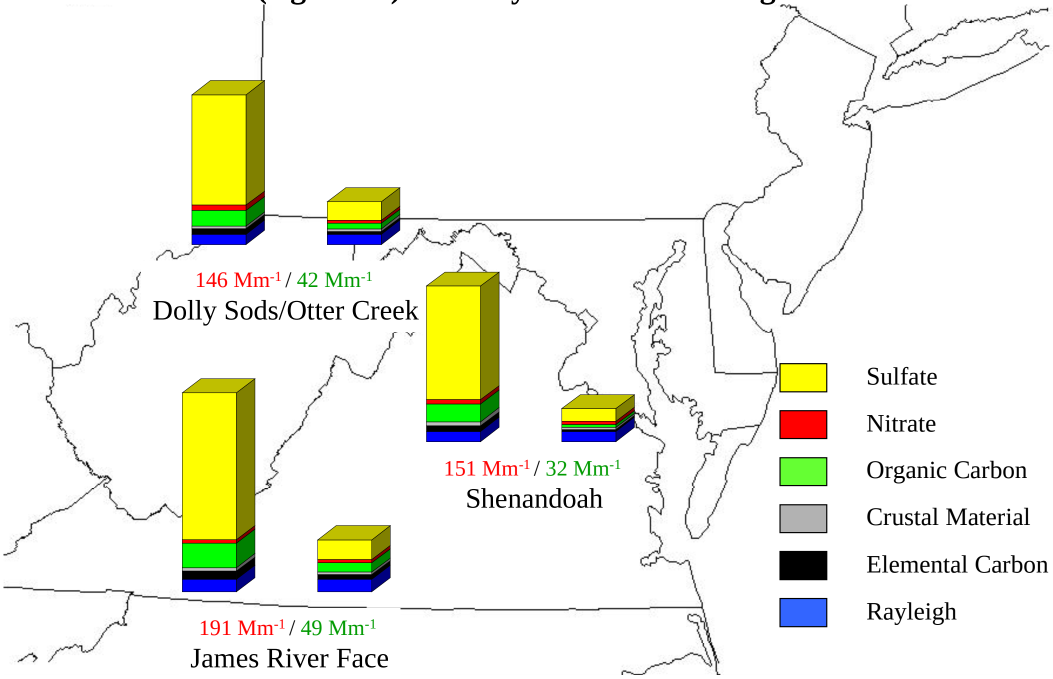
[11] These calculations use a climatological monthly mean relative humidity adjustment factor consistent with recent USEPA guidance on the subject. Discussion of how these factors differ from alternatives is presented in section IV of this memorandum.

Figure 2: Speciated contribution to total atmospheric light extinction in or near Class I areas in Virginia and West Virginia on 20 percent of days with the worst (left bar) and best(right bar) visibility conditions during 1999.



IV. Visibility Trends

As discussed in the last section, 1999 visibility conditions appear to have been better than those of other recent years. We caution the reader, however, that an analysis of the meteorological conditions in 1999 and earlier years should be performed before concluding that a significant improvement in visibility conditions (on the order of 2 dv) has occurred as a result of reductions in anthropogenic emissions. The one-in-three day data collection schedule of the IMPROVE program may have also contributed, in part, to an improved trend if the worst visibility days happened to occur mostly on days when no sampling was taking place. The trend charts shown in this report (see Figure 3-12 later in this section) reflect the improved visibility relative to prior years, but additional years of data will be required to determine if this trend is sustained or whether the improvement was temporary.

Determining what role meteorology plays in year to year variation of average visibility conditions is complicated. Individual terms in the equation for reconstructed light extinction are proportional to the fine particle mass as well as the relative humidity correction factor and, therefore, reconstructed extinction will be sensitive to year-to-year variation in both of these factors.[12] In simplified terms, ambient fine particle mass is a function of emissions, transport, photochemistry, and deposition, which vary in time.

Relative humidity also varies year-to-year, but recent guidance on tracking reasonable progress (USEPA, 2001a) suggests a method for removing this variability. By using climatological mean relative humidity adjustment factors, the sensitivity of reconstructed light extinction to interannual changes in relative humidity is removed completely. Essentially, the same humidity conditions are assumed to be experienced every year and thus any difference in visibility conditions is due to emissions or other meteorological factors. The advantage is that we can remove one confounding factor for verification of a regional haze control. The disadvantage is that we are not calculating precise visibility conditions in any given year.

A. Comparison of Timescales for Averaging Relative Humidity

In order to understand the differences between the use of climatological annual, climatological monthly or day-specific relative humidity adjustment factors, we have calculated reconstructed light extinction in three different ways. Consistent with previous NESCAUM reports and recommendations presented in the FLAG report, annual average relative humidity adjustment factors[13] have been used to calculate average visibility (in

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[12] Terms are also proportional to the dry scattering efficiency of the particular material, but this is a physical characteristic of each component and not subject to temporal variation.

[13] FLAG recommend the use of annual average relative humidity adjustment factor for screening analysis only. For detailed analyses, the use of daily average factors is preferred, when such data is available. The FLAG final report (FLAG, 2000) presents seasonal average factors for use when daily humidity data is unavailable. It should be noted that the annual and seasonal average factors presented in the FLAG final

deciviews) on the twenty percent of days with the worst and best visibility conditions.[14] These calculations have been repeated using monthly site-specific adjustment factors developed and recommended by USEPA in their recent guidance on tracking progress under the regional haze rule (USEPA, 2001a). In addition, daily relative humidity adjustment factors (based on actual humidity data as opposed to climatological means) were used to calculate reconstructed extinction values. All three techniques are compared in the following series of charts showing trends in the best and worst visibility at IMPROVE sites throughout the Northeast and Mid-Atlantic States (presented from northeast to southwest).

All of the values shown in these charts represent the simple average of visibility values (in dv) from the twenty percent of days with the worst and best visibility conditions each year. The difference between the two (or sometimes three) curves shown for worst visibility conditions at each site has to do with the averaging time used for relative humidity adjustment factor. For the blue curves, a single site-specific annual mean value for the relative humidity adjustment factor was used for the whole year. These values were obtained from the final Phase I Report of the Federal Land managers' Air quality related values workGroup (FLAG, 2000). For the red curves, 12 site-specific climatological monthly mean values were used for days in the corresponding month. These values were provided by the USEPA contractor (SAIC, personal communication) and were the basis for relative humidity adjustment factors listed in the recent USEPA guidance document (USEPA, 2001a). When measured daily relative humidity data was available (see Acadia and Camp Dodge Charts) the calculations were repeated using these data directly (green curves). Reconstructed light extinction was then calculated, converted to deciviews, and ranked from greatest to least. The twenty percent of days with the highest and lowest deciview values were usually the same, but not always. There were some instances when the use of a monthly (or daily) average relative humidity adjustment factor elevated a day (or dropped a day) into (or out of) the top twenty percent of the ranking. Appendix A contains a table of annual and monthly climatological mean values for relative humidity and the appropriate adjustment factors which were used for these calculations. Note that the FLAG reports do not list an annual correction factor nor relative humidity values for Washington, D.C. We have assumed that relative humidity and the associated correction factor for the Washington, D.C. IMPROVE monitor would be relatively close to values estimated for Shenandoah National Park and have used 3.0 for the annual value of the relative humidity correction factor for these calculations.

Results differ between sites. At most sites, visibility impairment is consistently underestimated on the worst days and overestimated on the best days using the annually-averaged factors relative to the values derived using monthly factors. However, the degree of difference is relatively small and at many sites (e.g. Lye Brook, Brigantine and

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phase I report differ substantially from those presented in the draft phase I report (FLAG, 1999) and subsequently used by NESCAUM in earlier assessments of visibility conditions in the Northeast and Mid-Atlantic region. The factors presented in the final phase I report are used here and are compared to the earlier values in Table A.1 and A.2 in Appendix A.

[14] See footnote 10 for a specific definitions of 20 percent worst and best conditions.

Washington D.C.) the two methods produce very similar results on the worst days. The two methods are in strong agreement at virtually all sites on the best visibility days (exceptions being Washington D.C. and James River Face). The two sites for which daily humidity data were available show that use of a daily factor produces values that are significantly higher (in dv) than those calculated using other methods. These results show that averaging humidity across a month or a year will tend to moderate the influence of hygroscopic aerosol in calculations of extinction. However, such a relationship has not been observed elsewhere (USEPA, 2001a, pg. 6-4) and is worthy of additional investigation.

Figure 3: Worst (top) and best (bottom) visibility trends at Moosehorn Wilderness Area

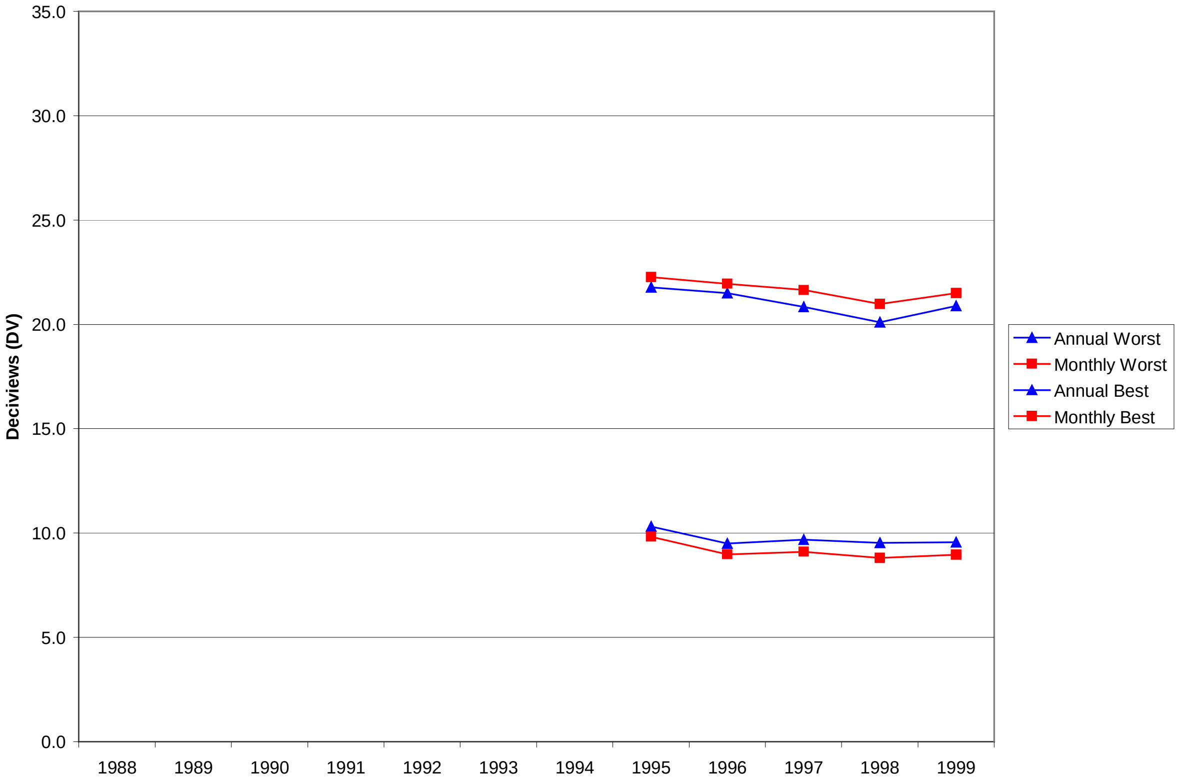


Figure 4: Worst (top) and best (bottom) visibility trends at Acadia National Park

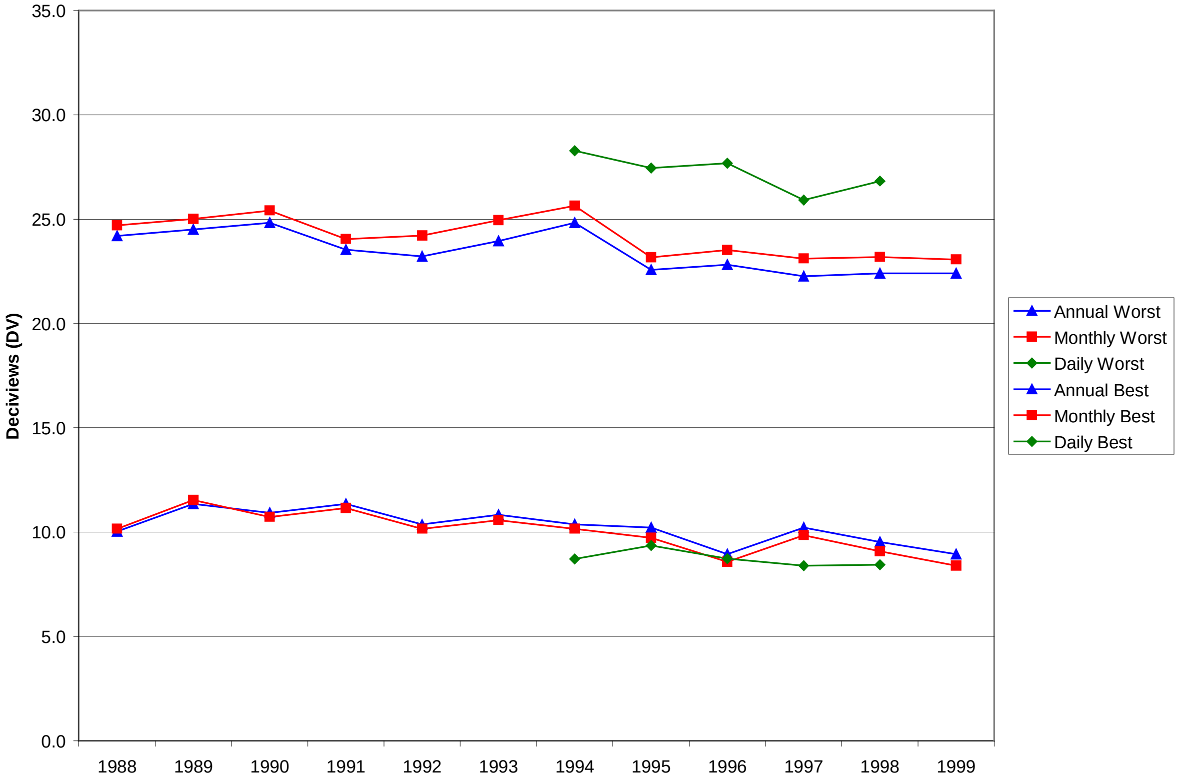
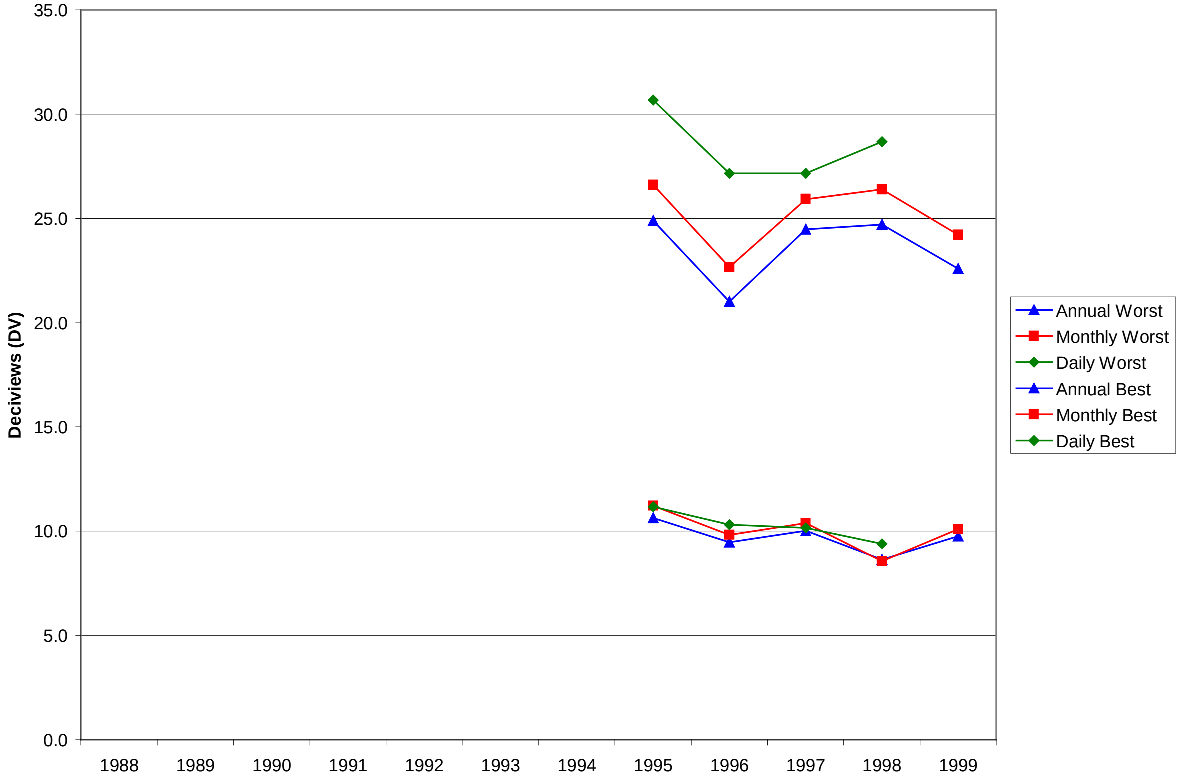


Figure 5: Worst (top) and best (bottom) visibility trends at Camp Dodge (IMPROVE monitor near Great Gulf and Presidential Range – Dry River Wilderness Areas)



note: The Camp Dodge IMPROVE monitor collects data in summertime only.

Figure 6: Worst (top) and best (bottom) visibility trends at Lye Brook Wilderness Area

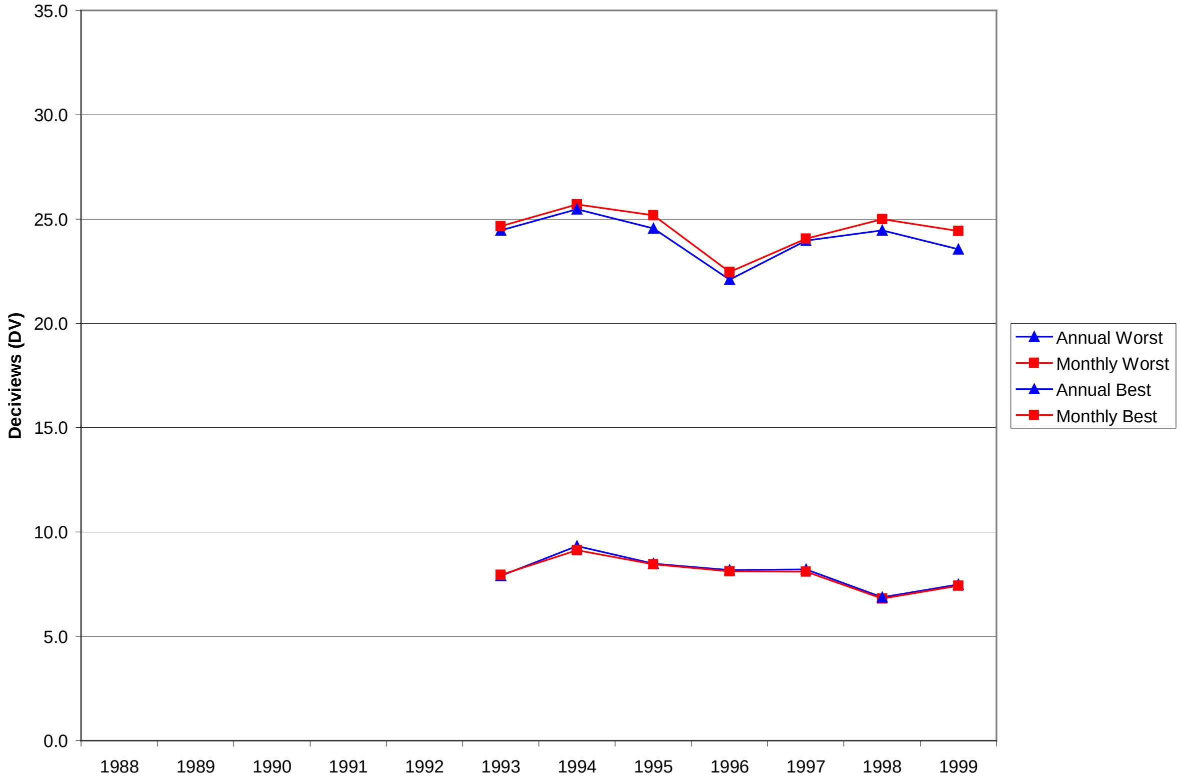


Figure 7: Worst (top) and best (bottom) visibility trends at Brigantine Wilderness Area

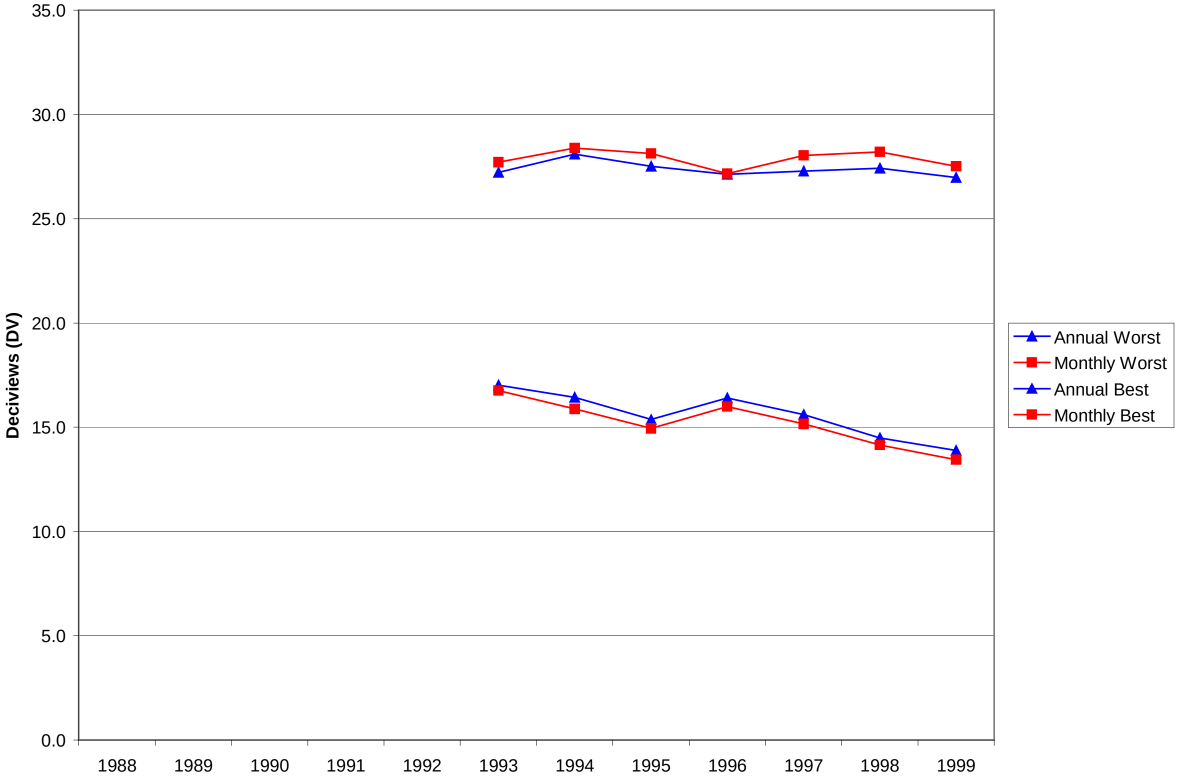
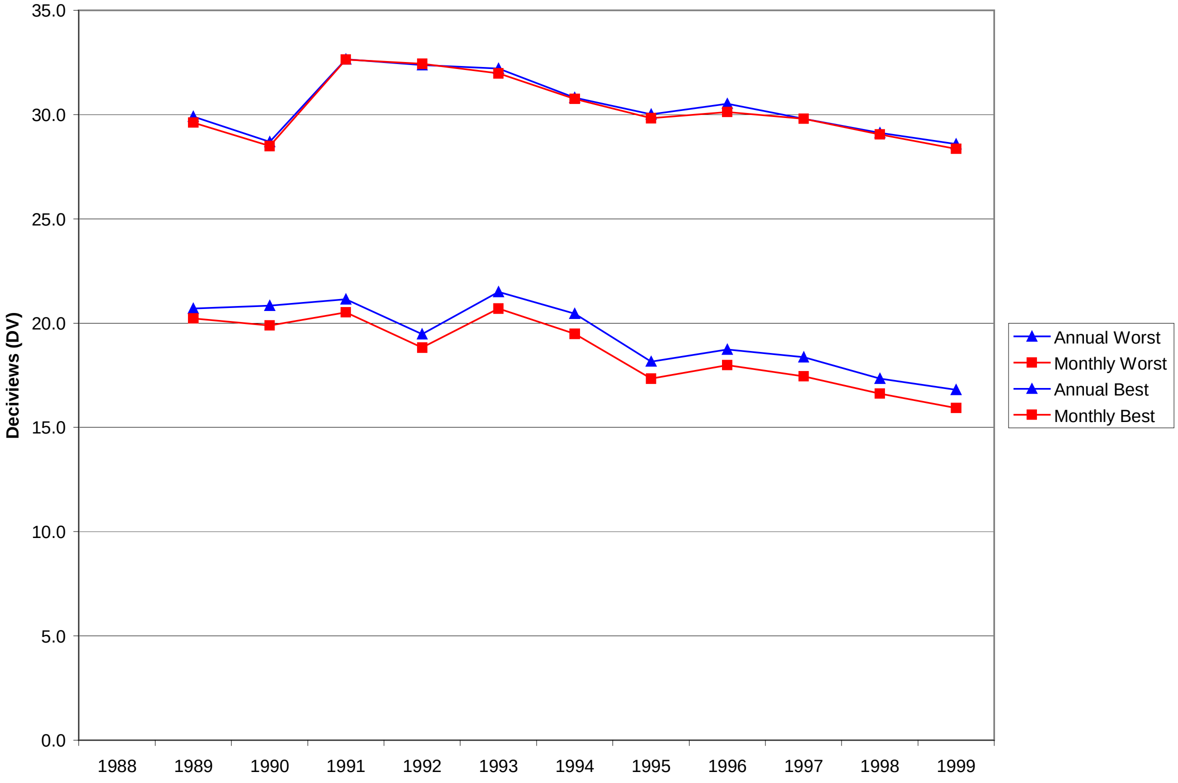


Figure 8: Worst (top) and best (bottom) visibility trends at Washington D.C.



note: The Washington D.C. IMPROVE data reflect urban conditions

Figure 9: Worst (top) and best (bottom) visibility trends at Shenandoah National Park

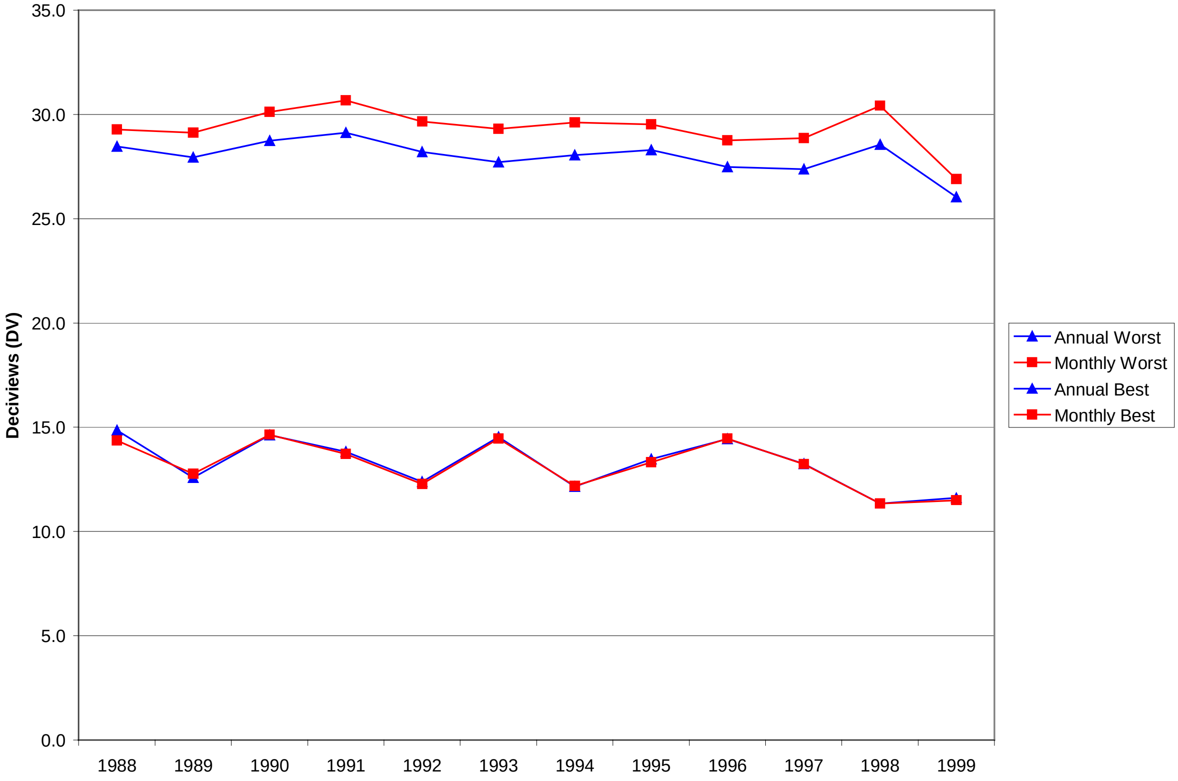


Figure 10: Worst (top) and best (bottom) visibility trends at Dolly Sods Wilderness Area

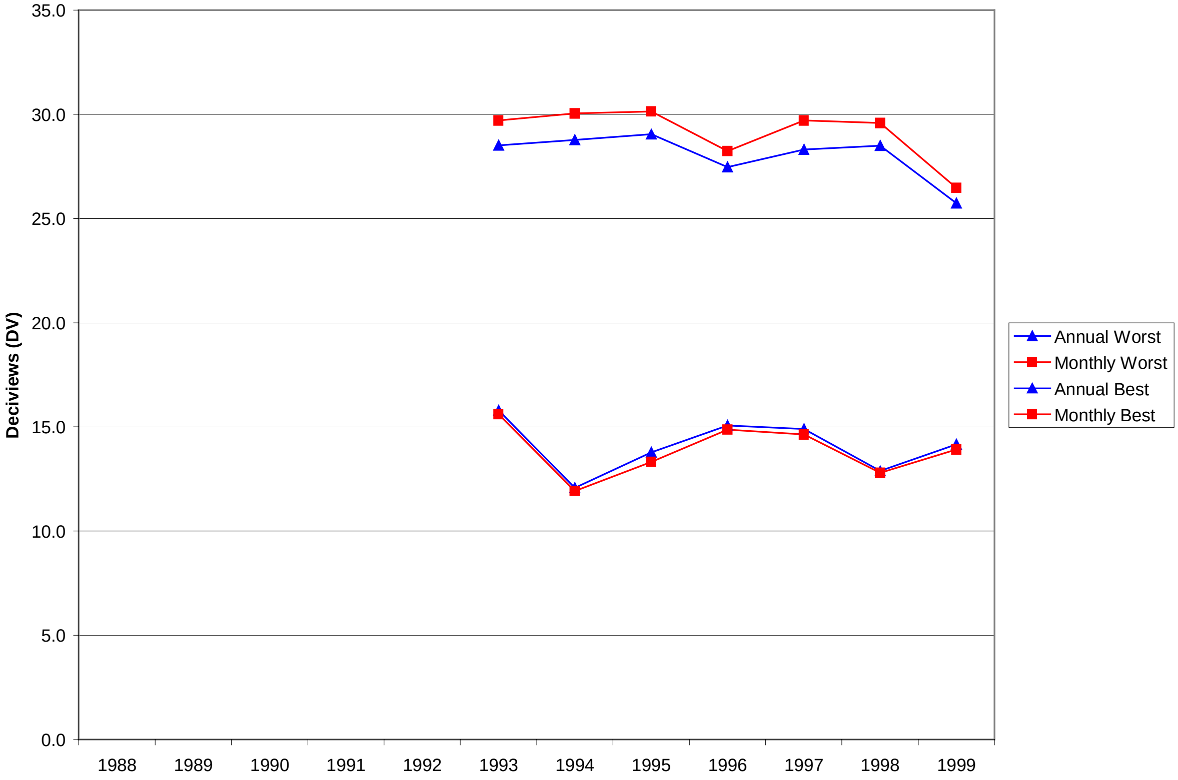


Figure 11: Worst (top) and best (bottom) visibility trends at James River Face Wilderness Area

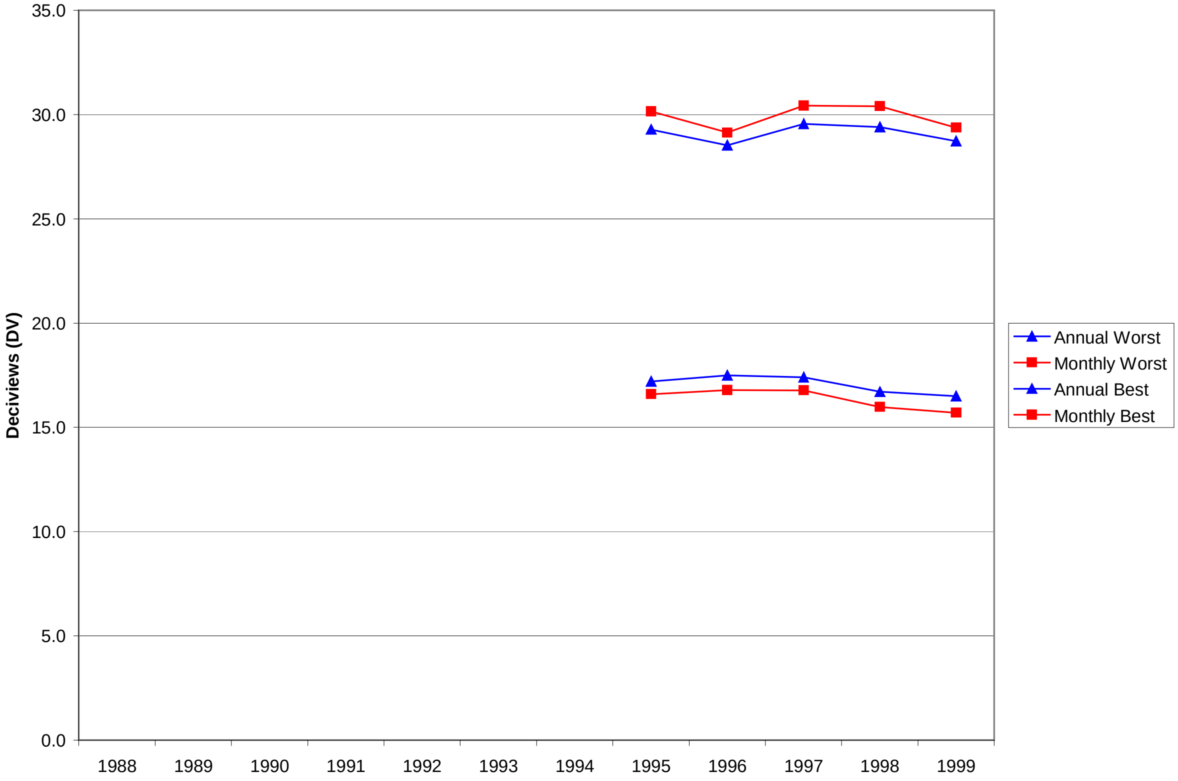
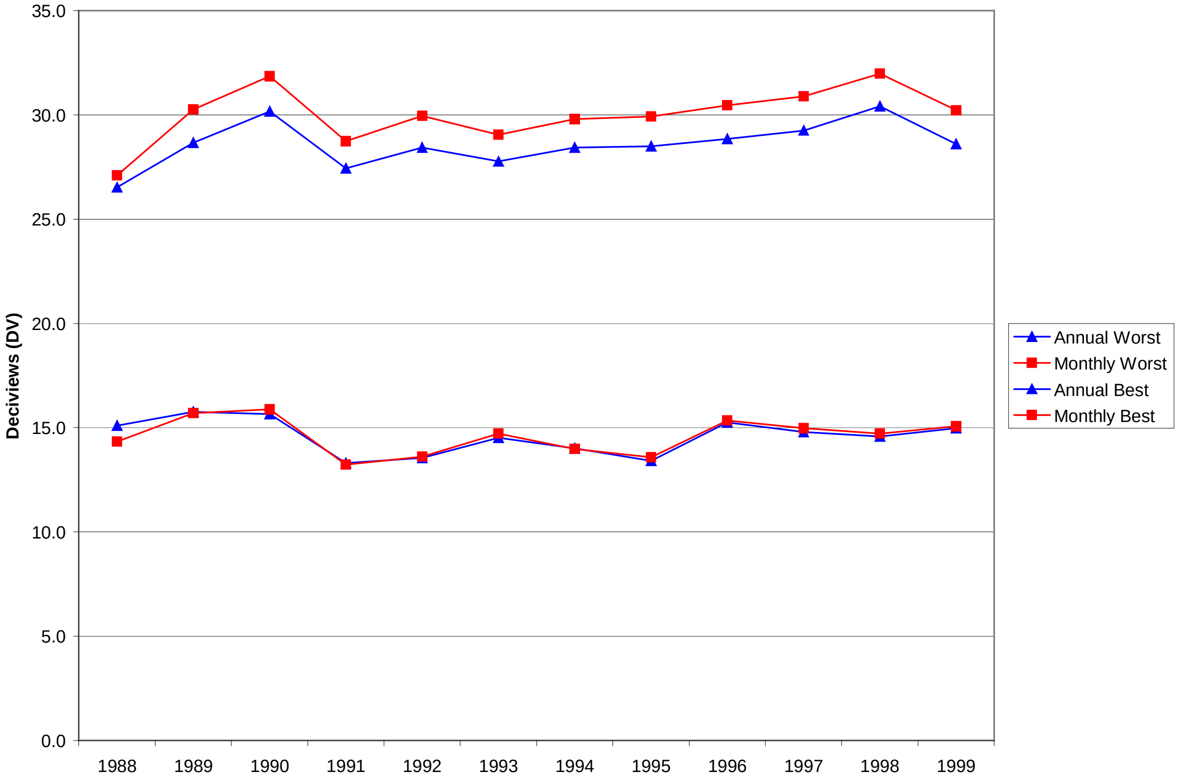


Figure 12: Worst (top) and best (bottom) visibility trends at Great Smoky Mountain National Park



B. Five-year average trends

USEPA's *Draft Guidance on Tracking Progress Under the Regional Haze Rule* (USEPA, 2001a) specifically requires the use of five-year averages for determining success with visibility goals in State Implementation Plans. As opposed to the trends shown in the preceding section, trends in five-year averages are more difficult to discern as each point represents five years worth of data, and thus any interannual variability is smoothed to a much greater degree.

Figure 13 shows trend lines for the twenty percent worst visibility days calculated using climatological mean monthly relative humidity adjustment factors as advocated in the guidance document. The year specified on the x-axis represents the middle year of the five used for each data point. Thus the data record ends with 1997 which is based on data from the years 1995-1999. Trends for the twenty percent best days have also been calculated using five-year averages and are shown in Figure 14. In general, we see that visibility has remained unchanged or improved at most IMPROVE monitoring sites on the best and worst visibility days. The exception is Great Smoky Mountain National Park where significant degradation of visibility conditions is apparent.

Figure 13: Worst day visibility trends based on five-year average values of visibility (dv) for MANE-VU and nearby Class I areas.

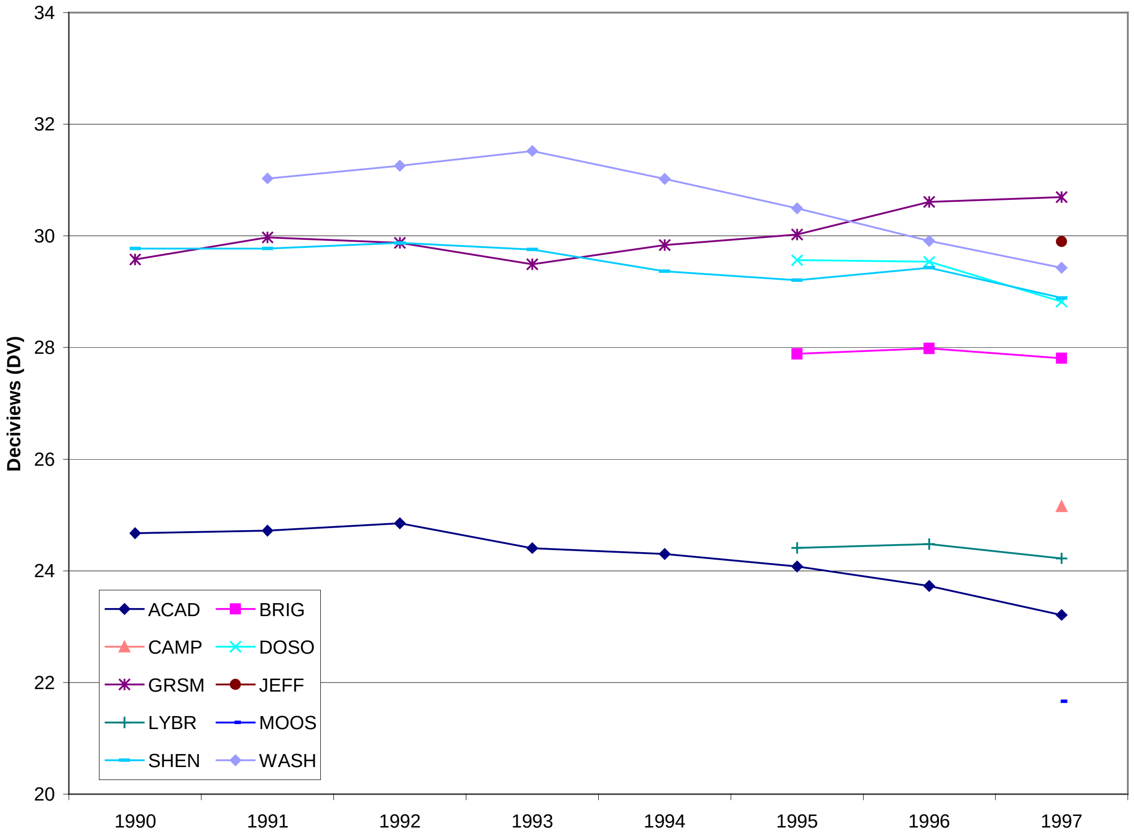
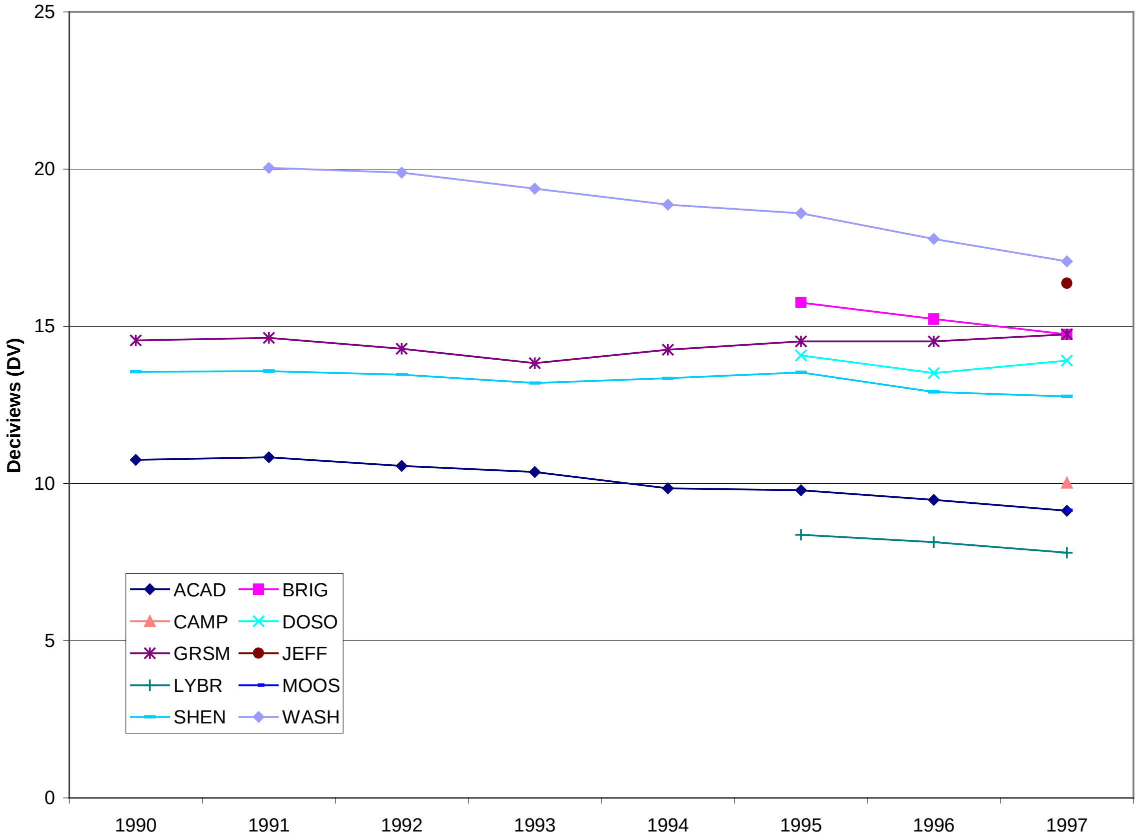


Figure 14: Best day visibility trends based on five-year average values of visibility (dv) for MANE-VU and nearby Class I areas.



C. Trends in Composition on the Best and Worst Visibility Days

In addition to looking at trends in overall visibility conditions, it is interesting to look at trends in extinction from individual components of fine particles. Figures 13-18 show speciated contribution to extinction for three IMPROVE sites in the MANE-VU region across years for which data was available. The three sites shown are Acadia National Park, Lye Brook Wilderness Area, and Brigantine Wilderness Area. Climatological monthly mean relative humidity adjustment factors were used for these calculations of species specific atmospheric extinction.

On the best visibility days, a slight reduction in the extinction due to sulfates and nitrates is evident.[15] No apparent trends are evident in organic carbon or crustal material; however, crustal material does exhibit a significant amount of variability. This variability in what is ostensibly a natural phenomenon, may be indicative of meteorological

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[15] This finding is further supported by EPA's *1999 Emissions and Air Quality Trends Report* which found visibility trends in sulfate and nitrate levels were decreasing on the best and "middle" twenty percent of days.

variability. Elemental carbon may have decreased slightly at Acadia over the 1988-99 time period.

There appears to be a slight reduction in nitrate extinction on the worst days, but trends in sulfate – the principal contributor to visibility impairment at all sites – are difficult to discern. The second largest contributor to extinction at all three sites, organic material, has remained relatively unchanged during the period.

Figure 13: Speciated contribution to extinction observed at Acadia National Park on the 20 percent of days with the worst visibility between 1988 and 1999.

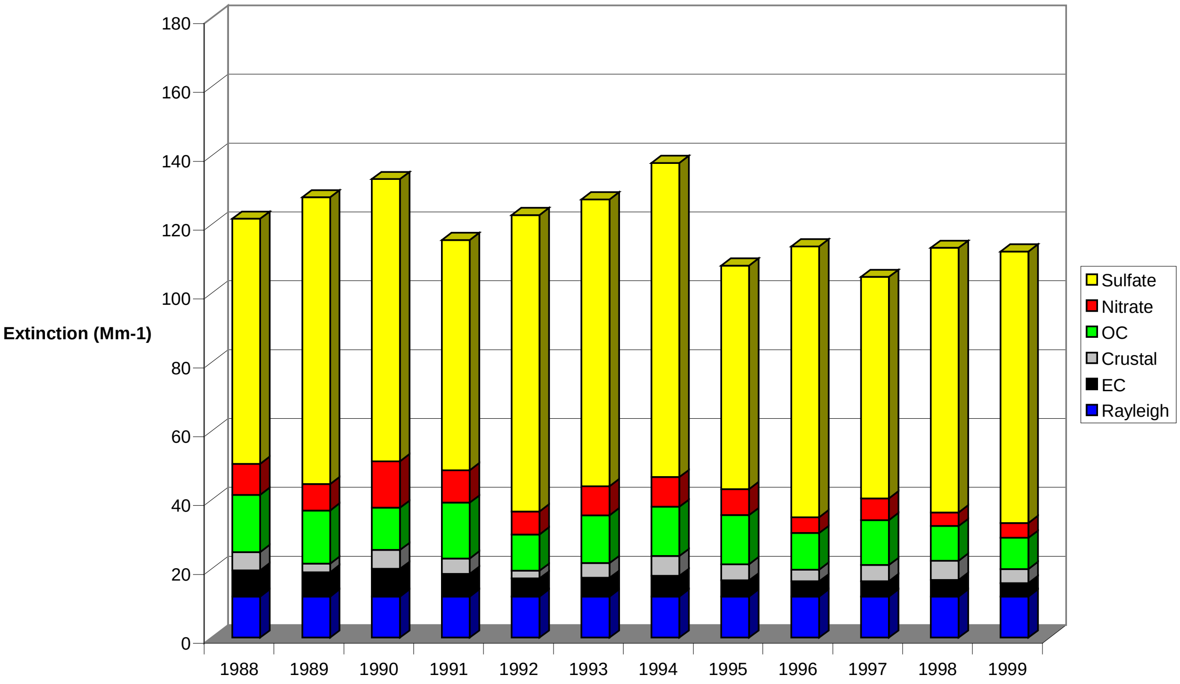


Figure 14: Speciated contribution to extinction observed at Acadia National Park on the 20 percent of days with the best visibility (note difference in scale) between 1988 and 1999.

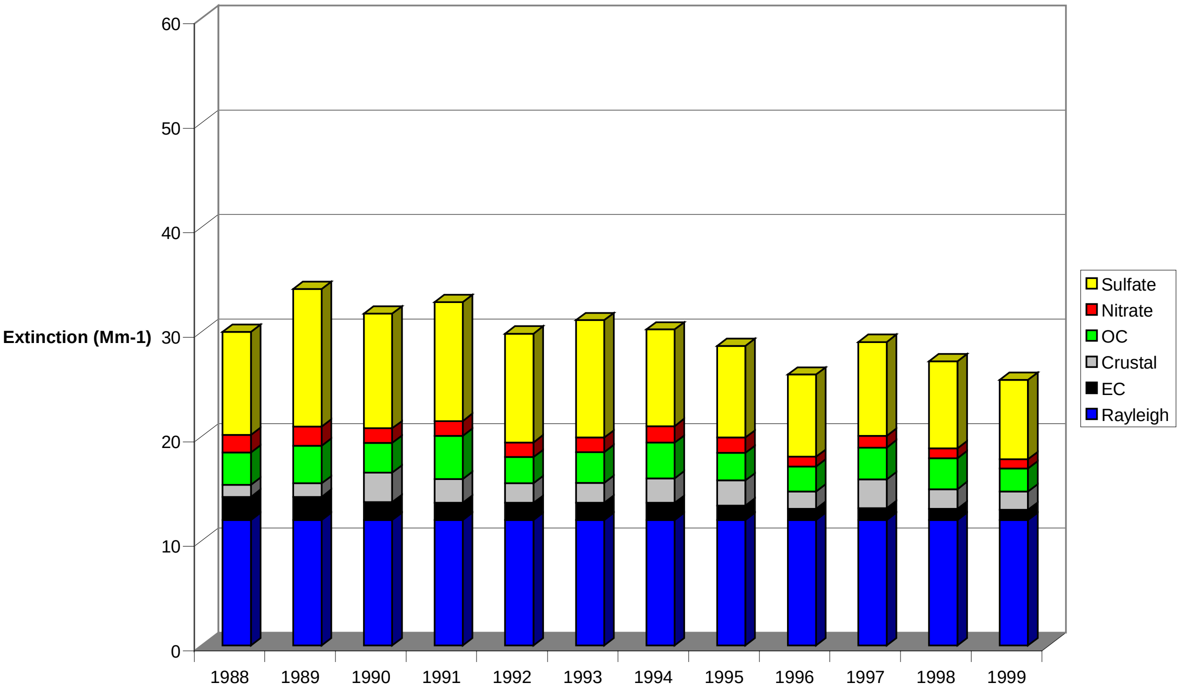


Figure 15: Speciated contribution to extinction observed at Lye Brook Wilderness Area on the 20 percent of days with the worst visibility between 1993 and 1999.

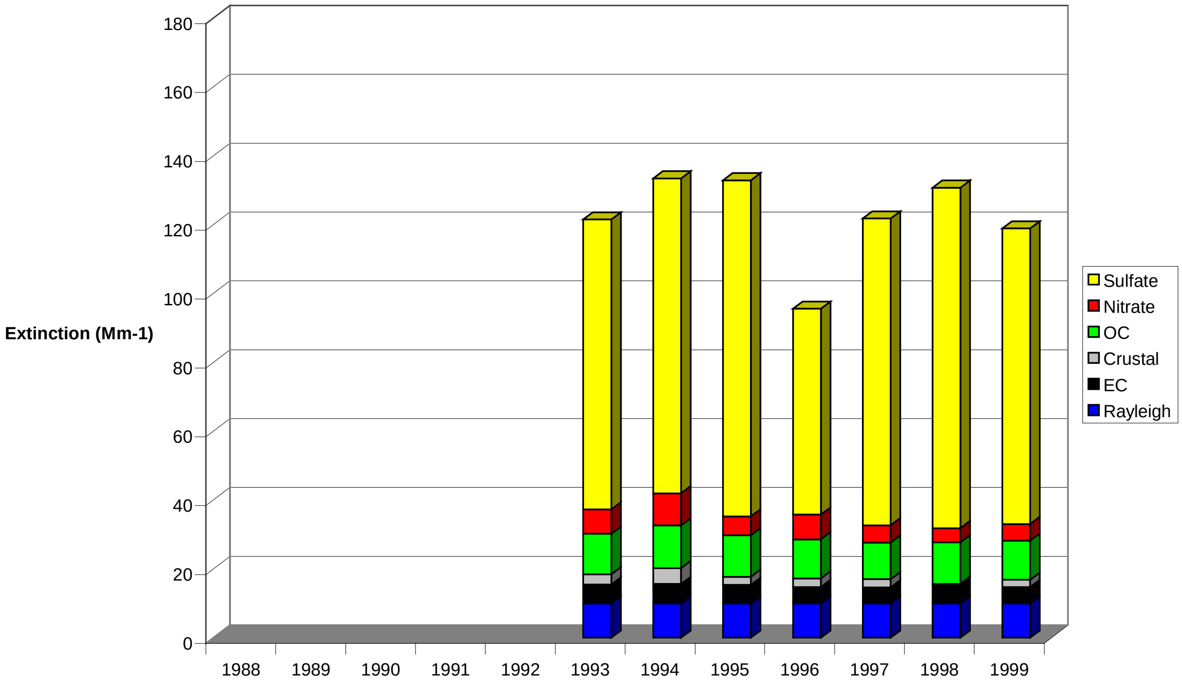


Figure 16: Speciated contribution to extinction observed at Lye Brook Wilderness Area on the 20 percent of days with the best visibility (note difference in scale) between 1993 and 1999.

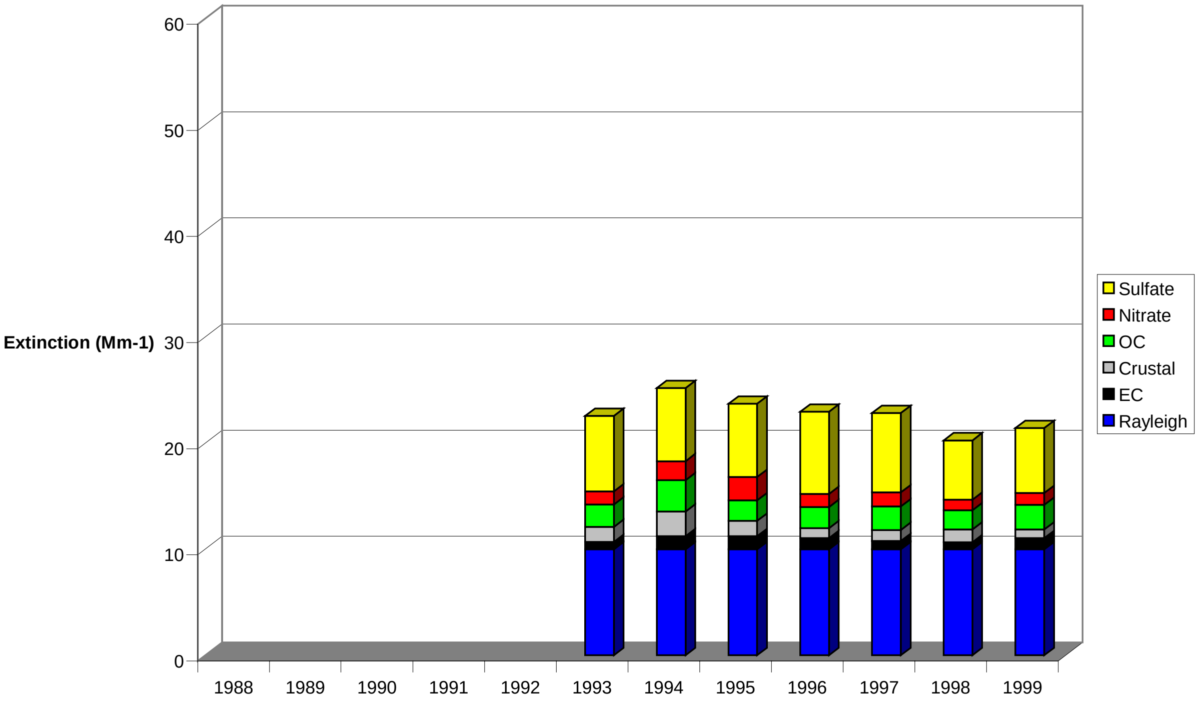


Figure 17: Speciated contribution to extinction observed at Brigantine Wilderness Area on the 20 percent of days with the worst visibility between 1993 and 1999.

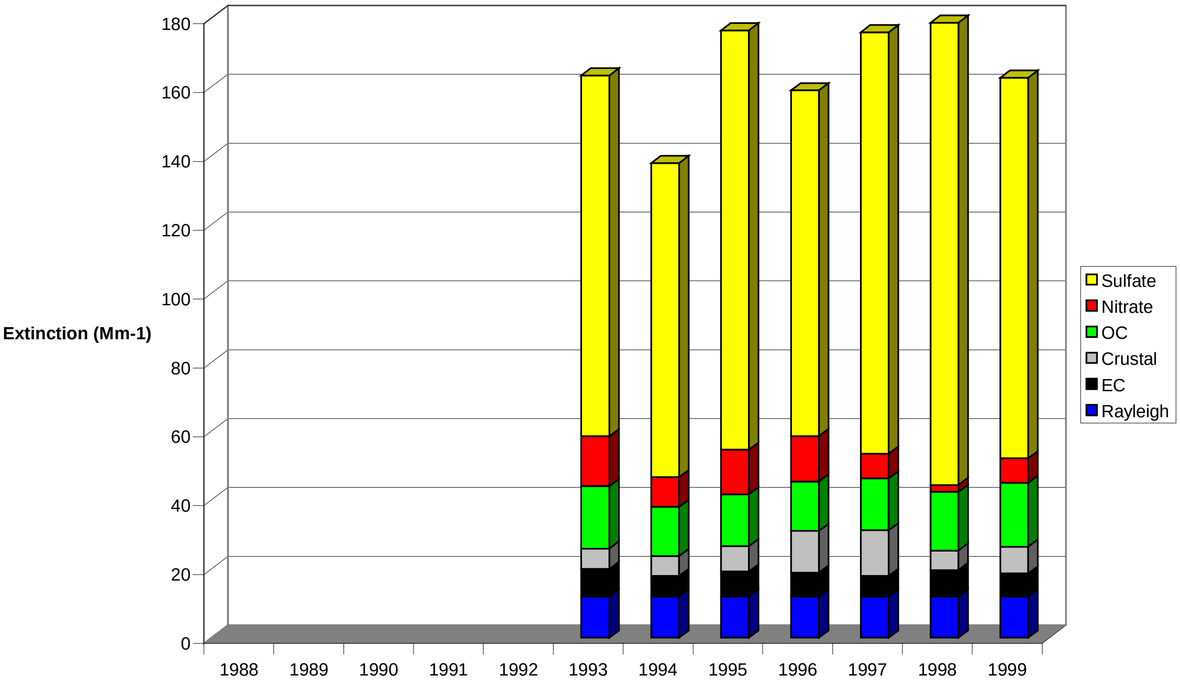
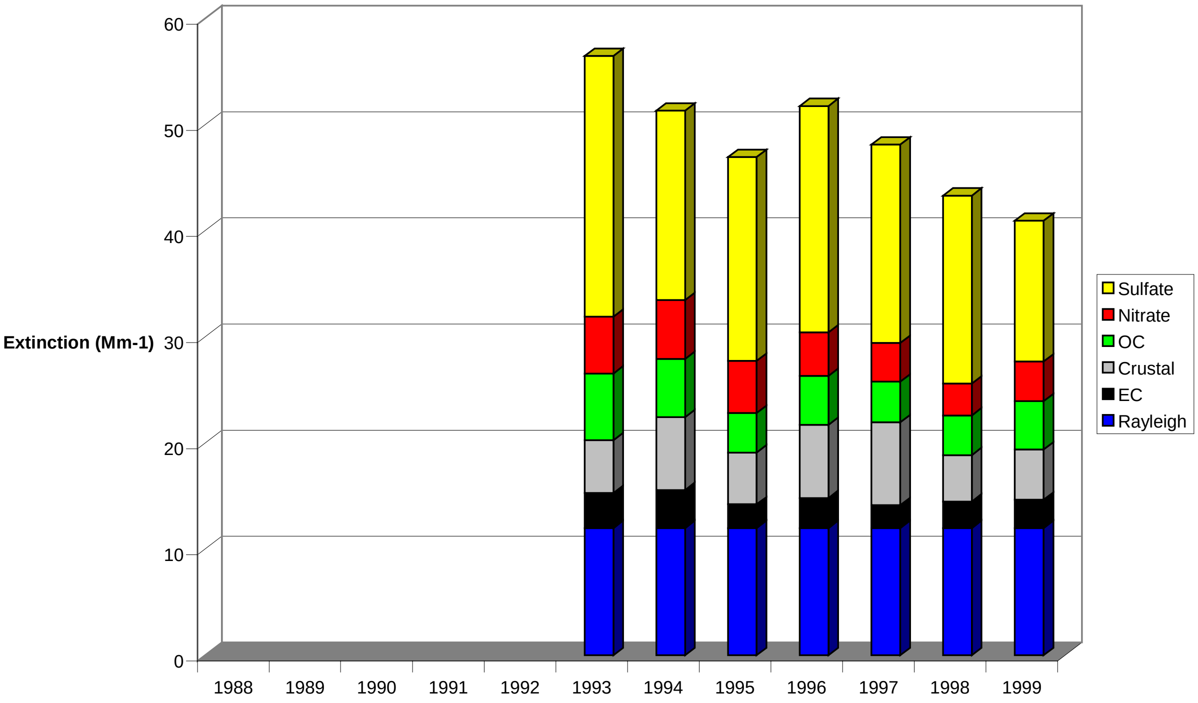


Figure 18: Speciated contribution to extinction observed at Brigantine Wilderness Area on the 20 percent of days with the best visibility (note difference in scale) between 1993 and 1999.



V. Comparing Optical vs. Aerosol Monitoring Techniques

The transmissometer and nephelometer are the most common instruments used for optical monitoring. Transmissometers operate over an open path of 1 km to 10 km and measure total light extinction (b_{ext}) by determining the loss of light (due to scattering and absorption of the intervening atmosphere) from an artificial light source of known luminescence at a fixed distance. Nephelometers measure light scattering (b_{scat}), which is responsible for most light extinction in rural areas of the eastern U.S. Nephelometers operate over a very short open path (few inches) and are easier to install and maintain than transmissometers. However, they measure only a portion (albeit a large majority) of total light extinction. Light absorption (b_{abs}) can be measured continuously by aethalometers and other instruments, which measure the amount of light absorbed by particles collected on a filter. Absorption is typically estimated from the concentration of elemental carbon collected on IMPROVE filters or by subtracting nephelometer data (b_{scat}) from transmissometer data (b_{ext}). Relatively few aethalometers have been deployed in the field.

Reconstructed light extinction obtained from aerosol monitoring techniques compares fairly well with light attenuation as measured by transmissometers and nephelometers; however, the level of agreement is dependant on how relative humidity is treated in the calculation (Malm, 2000). In order to understand the differences between optical and aerosol techniques, reconstructed light extinction was compared to measured extinction obtained by the IMPROVE program.

Figure 19 shows reconstructed light extinction plotted against measured extinction derived from transmissometer data at Acadia National Park between 1988 and 1993. The reconstructed extinction values plotted in Figure 19 are based on calculations using climatological monthly mean relative humidity factors. Significantly more data were available for this type of comparison from the Shenandoah National Park IMPROVE monitor. Figure 20 shows similar data for this more southerly location during 1999 only. A review of the data indicates that some values which would be considered among the twenty percent worst based on reconstructed light extinction would not qualify among the twenty percent worst days based on measured light extinction and vice versa. While this conclusion can not be definitively drawn due the high number of unpaired values, it does point to a potential inaccuracy incurred by the use of reconstructed light extinction.[16]

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[16] It should be noted that perfect agreement between reconstructed light extinction based on aerosol measurements and light extinction measured directly by a transmissometer are not expected to give perfect agreement since aerosol measurments are collected at a single ground-level site, whereas a transmissometer provides the integrated visibility conditions across a line of site, usually somewhat above the surface.

Figure 19: Comparison of measured extinction (transmissometer data) to reconstructed light extinction (b_{ext}; calculated using climatological mean monthly relative humidity adjustment factors) at Acadia National Park between 1988 and 1993.

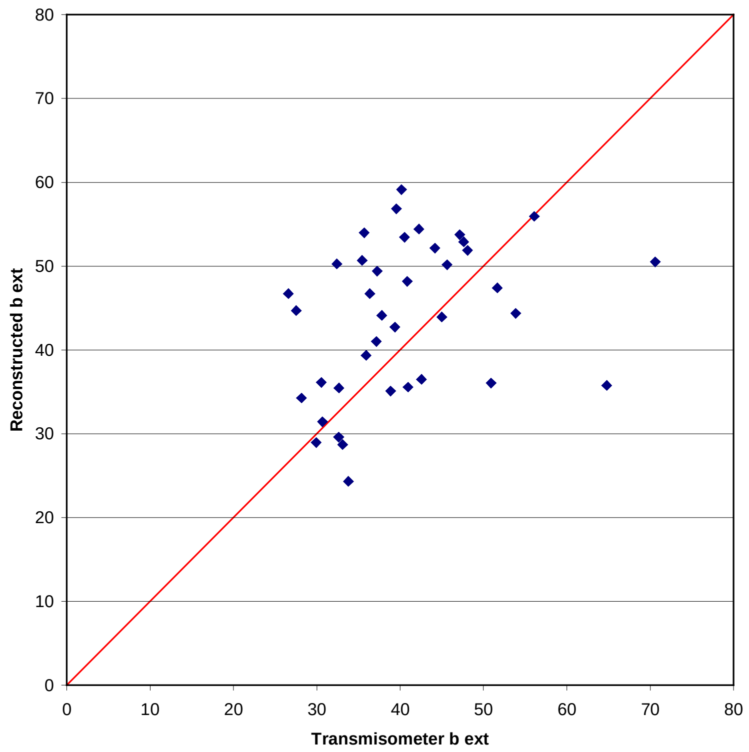
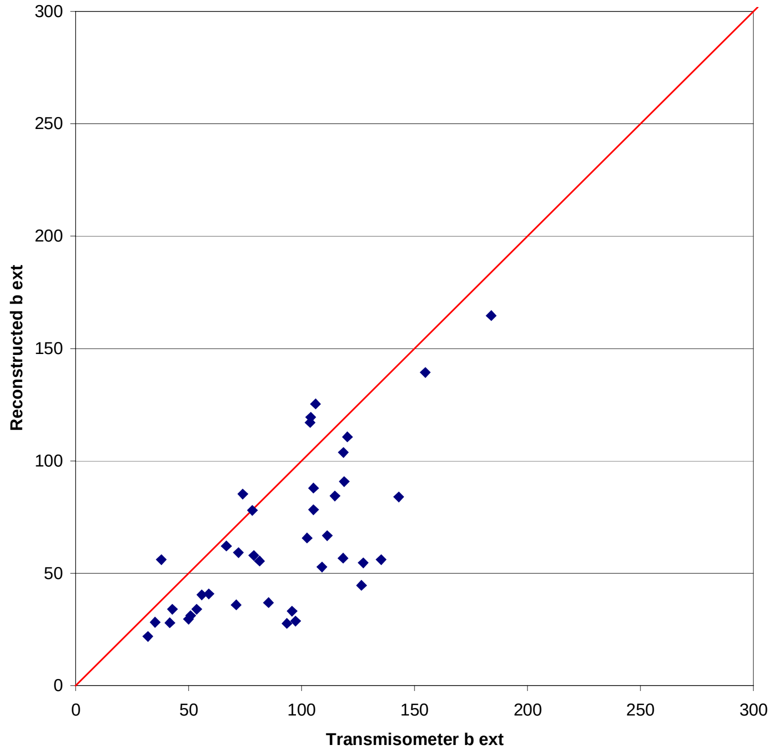


Figure 20: Comparison of measured extinction (transmissometer data) to reconstructed light extinction (b_{ext}; calculated using climatological mean monthly relative humidity adjustment factors) at Shenandoah National Park during 1999.



Some IMPROVE sites also have nephelometers deployed which measure total scattering (b_{scat}). Figure 21 compares the reconstructed scattering coefficient calculated using climatological mean monthly relative humidity adjustment factors with measured scattering coefficients derived from nephelometer data collected at Acadia during 1997. Figure 22 shows the same figure, with reconstructed scattering coefficients that have been calculated using actual relative humidity data measured at Acadia. This figure shows that the agreement is clearly much better when actual data is used, and suggests that the use of monthly average factors may bias the reconstructed scattering values high.

The issues that these figures raise with respect to the use of climatological mean monthly factors are complex. By using climatological monthly values, any year to year variation in visibility which can be attibuted to interannual relative humidity variation is removed. Hence, reasonable progress calculations based on climatological mean factors will specifically track that portion of any visibility improvement which is due to emissions reductions of haze contributing pollutants. If climatological mean values are used consistently for the baseline period and for future calculations of visibility conditions, then any bias due to the use of monthly average factors on reconstructed extinction values is likely to be consistent across both time periods (i.e. extinction calculated for the baseline period and for out years are both likely to be off in the same direction). Given that the deciview is the metric upon which “rate of progress” calculations are based, and it is logarithmically related to extinction, the difference between two equally biased extinction values, will not necessarily translate into two equally biased deciview values. Therefore, further study is required to understand the effect that these potential biases may introduce in “rate of progress” calculations for setting visibility goals.

Figure 21: Comparison of measured scattering (nephelometer data) to reconstructed scattering (b_{scat}; calculated using climatological mean monthly relative humidity adjustment factors) at Acadia National Park during 1997.

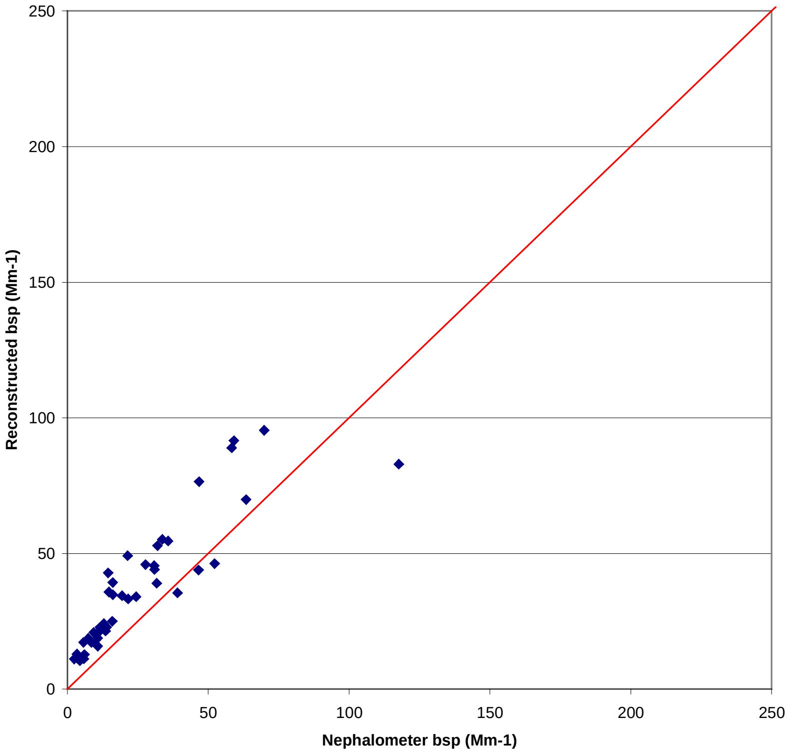
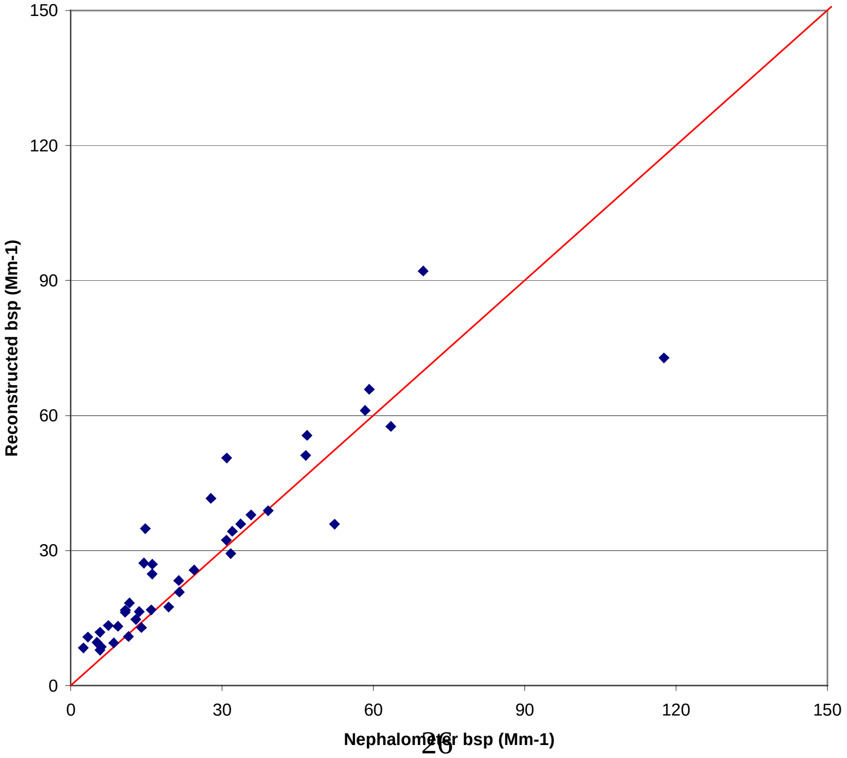


Figure 22: Comparison of measured scattering (nephelometer data) to reconstructed scattering (b_{scat}; calculated using daily relative humidity adjustment factors) at Acadia National Park during 1997.



VI. Summary

The IMPROVE network has generated a significant quantity of data for the MANE-VU Class I areas and those nearby. Analysis of these data continues to be an important source of information on baseline visibility conditions and year-to-year variability. The latest IMPROVE results indicate that MANE-VU Class I areas experienced significantly improved visibility in 1999 over 1997, the most recent year previously assessed by MANE-VU. The reasons for this improvement are not known definitively; however, meteorological variability and the IMPROVE sampling schedule may have played a role in addition to changes in anthropogenic emissions. Analysis of data from subsequent years will be required to determine if a statistically significant trend has been established or whether 1999 was a temporary improvement.

Differences in annual average visibility conditions (calculated in deciviews) are apparent depending on how relative humidity adjustment factors are handled in the calculations. Annual and monthly climatological mean values of the relative humidity adjustment factor have been compared against factors calculated for daily average relative humidity measured at two sites. This limited analysis of the data indicates that climatological mean values may underestimate visibility conditions on the worst days, however, other studies have not supported this conclusion.

While overall trends in visibility have shown marginal improvements, trends in some of the individual components of fine particulate matter measured at IMPROVE sites in the MANE-VU region have not been observed. Continued analysis of IMPROVE data from the regional haze baseline period (2000-2004) should help in identifying any trends in specific components of fine particulate if they exist. Ideally, such analysis should attempt to account for variations in meteorology not accounted for by the use of climatological relative humidity adjustment factors.

Finally, a comparison of measured and reconstructed light extinction has shown reasonable agreement between these techniques at some locations. Further study is required to fully understand the sensitivity of calculated rates of progress to the use of climatological mean values of relative humidity adjustment factors versus daily averages of observed humidity.

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Appendix A – Site specific, climatologically averaged relative humidity and relative humidity adjustment factors and other visibility statistics

Table A.1 – Site specific, climatological average relative humidity (data listed in percent)

Site	FLAG 1999	FLAG 2000	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ACAD	87	82	69	66	64	64	65	66	71	74	74	73	72	72
BRIG	88	82	67	64	64	62	66	69	72	74	74	71	67	68
CAMP	88	82	68	65	63	63	64	68	71	73	74	71	70	69
DOSO	89	83	69	66	65	61	67	70	72	74	74	69	68	71
GRSM	85	84	70	66	64	62	70	77	76	77	76	72	70	71
JEFF	83	82	66	63	62	59	67	71	72	74	73	68	65	68
LYBR	87	82	68	65	64	62	64	67	70	73	74	70	69	69
MOOS	88	82	70	66	63	64	64	67	70	73	74	72	72	72
SHEN	87	82	67	64	63	60	66	71	73	75	74	69	65	68
WASH	N/A	N/A	65	61	62	61	67	68	69	71	71	70	65	65

Notes: Annual Data based on FLAG draft phase I report (1999) and final report in 2000. Monthly data provided by SAIC under contract to USEPA (see USEPA, 2001a). Note that significant differences exist between the draft and final FLAG annual estimates. Additionally, large differences exist between annual FLAG and the monthly USEPA estimates of relative humidity. However, the differences between FLAG and USEPA correction factors (Table A.2) are much smaller suggesting different relationships were used for calculating correction factors from relative humidity data.

Table A.2 – Site specific, climatological average relative humidity adjustment factor (unitless)

Site	FLAG 1999	FLAG 2000	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ACAD	3.8	3.0	3.26	2.94	2.84	3.37	3.11	2.98	3.41	3.83	4.04	3.82	3.56	3.53
BRIG	3.9	3.0	2.83	2.64	2.73	2.6	3.03	3.16	3.44	3.72	3.64	3.34	2.85	2.83
CAMP	3.9	3.0	2.78	2.56	2.58	2.77	2.93	3.22	3.49	3.81	3.98	3.42	3.06	2.92
DOSO	4.3	3.1	2.98	2.79	2.81	2.56	3.12	3.39	3.54	3.87	3.85	3.27	2.97	3.1
GRSM	3.4	3.2	3.31	3.04	2.91	2.7	3.17	3.86	3.82	3.96	4.24	3.77	3.29	3.44
JEFF	3.1	3.0	2.83	2.64	2.66	2.43	2.98	3.28	3.39	3.67	3.64	3.15	2.81	2.96
LYBR	3.8	3.0	2.74	2.56	2.61	2.59	2.82	3.03	3.27	3.56	3.66	3.25	2.93	2.83
MOOS	3.9	3.0	2.97	2.69	2.66	3.01	2.96	3.1	3.41	3.8	3.91	3.54	3.24	3.2
SHEN	3.8	3.0	3.07	2.83	2.79	2.53	3.05	3.41	3.54	3.93	3.85	3.21	2.95	3.07
WASH	N/A	N/A	2.74	2.47	2.62	2.42	3.03	2.89	2.98	3.05	3.31	3.14	2.69	2.64

Notes: Annual Data based on FLAG draft phase I report (1999) and final report (2000). Monthly data provided by SAIC under contract to USEPA (see USEPA, 2001a). Note that significant differences exist between the draft and final FLAG annual estimates. Additionally, large differences exist between annual FLAG and monthly USEPA estimates of relative humidity (Table A.1). As shown here, the FLAG and USEPA correction factors are in much better agreement suggesting different relationships were used for calculating correction factors from relative humidity data.

Table A.3 – Speciated contribution to atmospheric light extinction in or near Class I Areas in the Northeast and Mid-Atlantic states on 20% of days with the worst visibility conditions in 1999.

	Contribution to Extinction from						Total Extinction (Mm^{-1})	Total Extinction (dv)
	Sulfate (Mm^{-1})	Nitrate (Mm^{-1})	Organic Carbon (Mm^{-1})	Crustal Material (Mm^{-1})	Elemental Carbon (Mm^{-1})	Rayleigh Scattering (Mm^{-1})		
Acadia National Park, ME	78.9	4.3	9.1	4.1	3.9	12.0	112.2	24.2
Brigantine Wildlife Refuge, NJ	110.6	7.2	18.5	7.7	6.7	12.0	162.7	27. 9
Dolly Sodds /Otter Creek Wilderness, WV	107.2	5.2	15.3	2.4	5.4	10.0	145.5	26.8
Great Gulf Wilderness Area, NH	84.2	1.4	11.6	4.3	3.8	10.0	115.2	24.4
Great Smoky Mountains National Park, NC	168.2	2.0	19.4	5.4	5.3	10.0	210.2	30.5
Jefferson/James River Face Wilderness Area, VA	142.7	3.5	23.7	3.3	8.2	12.0	193.5	29.6
Lye Brook Wilderness Area, VT	85.9	4.8	11.3	2.1	4.8	10.0	118.9	24.8
Moosehorn Wildlife Refuge, ME	59.5	4.6	8.7	2.2	3.5	12.0	90.5	22.0
Shenandoah National Park, VA	110.5	4.1	17.3	4.1	5.3	10.0	151.2	27.2
Washington, DC	113.2	10.1	24.5	3.7	12.8	12.0	176.3	28.7

Table A.4 – Speciated contribution to atmospheric light extinction in or near Class I Areas in the Northeast and Mid-Atlantic states on 20% of days with the best visibility conditions in 1999.

	Contribution to Extinction from						Total Extinction (Mm^{-1})	Total Extinction (dv)
	Sulfate (Mm^{-1})	Nitrate (Mm^{-1})	Organic Carbon (Mm^{-1})	Crustal Material (Mm^{-1})	Elemental Carbon (Mm^{-1})	Rayleigh Scattering (Mm^{-1})		
Acadia National Park, ME	7.6	0.9	2.2	1.7	1.0	12.0	25.4	9.3
Brigantine Wildlife Refuge, NJ	13.3	3.7	4.6	4.8	2.7	12.0	41.0	14.1
Dolly Sodds /Otter Creek Wilderness, WV	18.0	3.0	5.4	2.7	2.4	10.0	41.6	14.3
Great Gulf Wilderness Area, NH	6.8	0.7	5.5	3.0	1.5	10.0	27.6	10.1
Great Smoky Mountains National Park, NC	19.8	2.2	6.9	3.5	3.1	10.0	45.6	15.2
Jefferson/James River Face Wilderness Area, VA	19.2	3.2	9.0	2.7	4.6	12.0	50.6	16.2
Lye Brook Wilderness Area, VT	6.1	1.1	2.3	0.8	1.0	10.0	21.4	7.6
Moosehorn Wildlife Refuge, ME	7.7	1.5	2.4	2.1	1.0	12.0	26.8	9.8
Shenandoah National Park, VA	12.3	3.1	3.0	1.9	1.8	10.0	32.1	11.7
Washington, DC	18.2	5.0	7.1	2.8	6.8	12.0	52.0	16.5

Table A.5 – Worst and best visibility trends at Acadia National Park, ME (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual	24.2	24.5	24.8	23.5	23.2	24.0	24.8	22.6	22.8	22.3	22.4	22.4
	Monthly	24.7	25.0	25.4	24.1	24.2	24.9	25.7	23.2	23.5	23.1	23.2	23.1
	Daily							28.3	27.4	27.7	25.9	26.8	
Best	Annual	10.0	11.4	10.9	11.4	10.4	10.8	10.4	10.2	8.9	10.2	9.5	8.9
	Monthly	10.2	11.5	10.7	11.2	10.2	10.6	10.2	9.7	8.6	9.9	9.1	8.4
	Daily							8.7	9.4	8.7	8.4	8.4	

Table A.6 – Worst and best visibility trends at Brigantine Wildlife Refuge, NJ (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual						27.2	28.1	27.5	27.1	27.3	27.4	27.0
	Monthly						27.7	28.4	28.1	27.2	28.0	28.2	27.5
Best	Annual						17.0	16.4	15.4	16.4	15.6	14.5	13.9
	Monthly						16.8	15.9	14.9	16.0	15.2	14.1	13.4

Table A.7 – Worst and best visibility trends at Dolly Sodds/Otter Creek Wilderness, WV (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual						28.5	28.8	29.0	27.5	28.3	28.5	25.7
	Monthly						29.7	30.0	30.1	28.2	29.7	29.6	26.5
Best	Annual						15.8	12.1	13.8	15.1	14.9	12.9	14.2
	Monthly						15.6	11.9	13.3	14.9	14.6	12.8	13.9

Table A.8 – Worst and best visibility trends at Great Gulf Wilderness, NH (Total extinction in deciviews, summer only)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual								24.9	21.0	24.5	24.7	22.6
	Monthly								26.6	22.7	25.9	26.4	24.2
	Daily								30.7	27.2	27.2	28.7	
Best	Annual								10.6	9.5	10.0	8.6	9.8
	Monthly								11.2	9.8	10.4	8.6	10.1
	Daily								11.2	10.3	10.2	9.4	

Table A.9 – Worst and best visibility trends at Great Smoky Mountains National Park, NC (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual	26.5	28.7	30.2	27.4	28.4	27.8	28.4	28.5	28.8	29.3	30.4	28.6
	Monthly	27.1	30.3	31.8	28.7	30.0	29.1	29.8	29.9	30.5	30.9	32.0	30.2
Best	Annual	15.1	15.8	15.7	13.3	13.6	14.5	14.0	13.4	15.3	14.8	14.6	15.0
	Monthly	14.3	15.7	15.9	13.2	13.6	14.7	14.0	13.6	15.4	15.0	14.7	15.1

Table A.10 – Worst and best visibility trends at Jefferson/James River Face Wilderness, VA (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual								29.3	28.5	29.5	29.4	28.7
	Monthly								30.1	29.1	30.4	30.4	29.4
Best	Annual								17.2	17.5	17.4	16.7	16.5
	Monthly								16.6	16.8	16.8	16.0	15.7

Table A.11 – Worst and best visibility trends at Lye Brook Wilderness, VT (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual						24.5	25.5	24.5	22.1	24.0	24.5	23.6
	Monthly						24.7	25.7	25.2	22.5	24.1	25.0	24.4
Best	Annual						7.9	9.3	8.5	8.2	8.2	6.9	7.5
	Monthly						8.0	9.1	8.5	8.1	8.1	6.8	7.4

Table A.12 – Worst and best visibility trends at Moosehorn Wildlife Refuge, ME (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual								21.8	21.5	20.8	20.1	20.9
	Monthly								22.3	21.9	21.6	21.0	21.5
Best	Annual								10.3	9.5	9.7	9.5	9.6
	Monthly								9.8	9.0	9.1	8.8	9.0

Table A.13 –Worst and best visibility trends at Shenandoah National Park, VA (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual	28.5	27.9	28.7	29.1	28.2	27.7	28.1	28.3	27.5	27.4	28.6	26.0
	Monthly	29.3	29.1	30.1	30.7	29.7	29.3	29.6	29.5	28.8	28.9	30.4	26.9
Best	Annual	14.9	12.6	14.6	13.8	12.4	14.5	12.2	13.5	14.4	13.2	11.4	11.6
	Monthly	14.4	12.8	14.6	13.7	12.3	14.5	12.2	13.3	14.5	13.2	11.3	11.5

Table A.14 – Worst and best visibility trends at Washington, DC (Total extinction in deciviews)

	Humidity Factor	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Annual		29.9	28.7	32.6	32.4	32.2	30.8	30.0	30.5	29.8	29.1	28.6
	Monthly		29.6	28.5	32.6	32.4	32.0	30.8	29.8	30.1	29.8	29.1	28.4
Best	Annual		20.7	20.8	21.1	19.5	21.5	20.5	18.2	18.7	18.4	17.3	16.8
	Monthly		20.2	19.9	20.5	18.8	20.7	19.5	17.3	18.0	17.5	16.6	15.9

Table A.15 – Worst visibility trends based on five-year average (Total extinction in deciviews)

Site	1988-1992	1989-1993	1990-1994	1991-1995	1992-1996	1993-1997	1994-1998	1995-1999
Acadia National Park, ME	24.68	24.73	24.86	24.41	24.30	24.08	23.73	23.21
Brigantine Wildlife Refuge, NJ						27.89	27.98	27.81
Dolly Sodds /Otter Creek Wilderness, WV								25.16
Great Gulf Wilderness Area, NH						29.56	29.54	28.82
Great Smoky Mountains National Park, NC	29.58	29.97	29.88	29.49	29.84	30.03	30.61	30.70
Jefferson/James River Face Wilderness Area, VA								29.90
Lye Brook Wilderness Area, VT						24.42	24.48	24.23
Moosehorn Wildlife Refuge, ME								21.66
Shenandoah National Park, VA	29.77	29.78	29.88	29.76	29.37	29.21	29.43	28.89
Washington, DC		31.03	31.26	31.53	31.02	30.50	29.91	29.43

Table A.16 – Best visibility trends based on five-year average (Total extinction in deciviews)

Site	1988-1992	1989-1993	1990-1994	1991-1995	1992-1996	1993-1997	1994-1998	1995-1999
Acadia National Park, ME	10.75	10.84	10.56	10.36	9.84	9.78	9.48	9.13
Brigantine Wildlife Refuge, NJ						15.75	15.22	14.74
Dolly Sodds /Otter Creek Wilderness, WV								10.02
Great Gulf Wilderness Area, NH						14.07	13.51	13.91
Great Smoky Mountains National Park, NC	14.55	14.63	14.29	13.83	14.25	14.52	14.52	14.74
Jefferson/James River Face Wilderness Area, VA								16.37
Lye Brook Wilderness Area, VT						8.36	8.13	7.79
Moosehorn Wildlife Refuge, ME								9.14
Shenandoah National Park, VA	13.55	13.57	13.46	13.19	13.34	13.53	12.91	12.77
Washington, DC		20.03	19.88	19.37	18.87	18.59	17.78	17.07

Table A.17 – Speciated contribution to extinction observed at Acadia National Park, ME on the 20 percent of days with the worst and best visibility using monthly relative humidity factors (Mm^{-1})

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Sulfate	71.1	83.3	82.0	66.8	86.1	83.3	91.2	64.9	78.7	64.3	76.9	78.9
	Nitrate	9.0	7.6	13.5	9.5	6.7	8.5	8.7	7.6	4.5	6.3	3.9	4.3
	Organic Carbon	16.6	15.5	12.3	16.2	10.6	13.8	14.3	14.2	10.7	13.1	10.1	9.1
	Crustal Matter	5.3	2.5	5.5	4.5	2.2	4.2	5.7	4.7	3.4	4.7	5.6	4.1
	Elemental Carbon	7.6	7.1	8.0	6.6	5.2	5.4	6.0	4.7	4.4	4.4	4.8	3.9
	Rayleigh Scattering	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
	Total Extinction	121.7	127.9	133.3	115.5	122.8	127.3	137.9	108.1	113.7	104.8	113.3	112.2
Best	Sulfate	9.9	13.2	11.0	11.4	10.4	11.2	9.2	8.8	7.9	9.0	8.3	7.6
	Nitrate	1.7	1.8	1.4	1.4	1.4	1.4	1.6	1.5	0.9	1.1	1.0	0.9
	Organic Carbon	3.1	3.6	2.8	4.1	2.5	2.9	3.4	2.6	2.4	3.1	3.0	2.2
	Crustal Matter	1.2	1.3	2.8	2.3	1.9	1.9	2.3	2.4	1.7	2.8	1.9	1.7
	Elemental Carbon	2.2	2.2	1.7	1.7	1.6	1.7	1.6	1.4	1.1	1.1	1.1	1.0
	Rayleigh Scattering	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
	Total Extinction	28.0	32.1	29.7	30.8	27.8	29.1	28.2	26.7	23.9	27.0	25.2	23.4

Table A.18 – Speciated contribution to extinction observed at Lye Brook Wilderness, VT on the 20 percent of days with the worst and best visibility using monthly relative humidity factors (Mm^{-1})

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Sulfate						84.2	91.5	97.7	59.8	89.1	98.9	85.9
	Nitrate						7.1	9.3	5.5	7.2	5.1	4.2	4.8
	Organic Carbon						11.8	12.4	12.0	11.3	10.6	12.0	11.3
	Crustal Matter						3.0	4.7	2.3	2.5	2.4	0.0	2.1
	Elemental Carbon						5.5	5.6	5.4	4.8	4.6	5.7	4.8
	Rayleigh Scattering						10.0	10.0	10.0	10.0	10.0	10.0	10.0
	Total Extinction						121.5	133.5	132.9	95.6	121.8	130.8	118.9
Best	Sulfate						7.1	6.9	6.9	7.8	7.5	5.6	6.1
	Nitrate						1.2	1.8	2.2	1.2	1.3	1.0	1.1
	Organic Carbon						2.1	3.0	1.9	2.0	2.2	1.8	2.3
	Crustal Matter						1.4	2.3	1.4	0.9	1.0	1.2	0.8
	Elemental Carbon						0.7	1.2	1.2	1.1	0.8	0.7	1.0
	Rayleigh Scattering						10.0	10.0	10.0	10.0	10.0	10.0	10.0
	Total Extinction						22.6	25.2	23.7	23.0	22.8	20.3	21.4

Table A.19 – Speciated contribution to extinction observed at Brigantine Wildlife Refuge, NJ on the 20 percent of days with the worst and best visibility using monthly relative humidity factors (Mm^{-1})

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Worst	Sulfate						104.8	91.2	121.7	100.5	122.4	134.3	110.6
	Nitrate						14.5	8.7	13.0	13.2	7.2	2.0	7.2
	Organic Carbon						18.1	14.3	15.1	14.3	15.1	17.1	18.5
	Crustal Matter						5.9	5.7	7.4	12.1	13.2	5.6	7.7
	Elemental Carbon						8.0	6.0	7.3	7.0	6.0	7.7	6.7
	Rayleigh Scattering						12.0	12.0	12.0	12.0	12.0	12.0	12.0
	Total Extinction						163.4	137.9	176.4	159.1	175.9	178.7	162.7
Best	Sulfate						24.6	17.8	19.2	21.3	18.7	17.7	13.3
	Nitrate						5.4	5.5	4.9	4.1	3.6	3.0	3.7
	Organic Carbon						6.3	5.5	3.7	4.6	3.8	3.7	4.6
	Crustal Matter						5.0	6.9	4.9	6.9	7.8	4.4	4.8
	Elemental Carbon						3.3	3.6	2.2	2.8	2.1	2.5	2.7
	Rayleigh Scattering						12.0	12.0	12.0	12.0	12.0	12.0	12.0
	Total Extinction						54.5	49.3	45.0	49.8	46.1	41.3	39.0

Mid-Atlantic Regional Air
Management Association

Development of Emission Projections
For 2009, 2012, and 2018
For NonEGU Point, Area, and Nonroad Source
In the MANE-VU Region

Final Report

February, 2007









About MARAMA

The Mid-Atlantic Regional Air Management Association is an association of ten state and local air pollution control agencies. MARAMA's mission is to strengthen the skills and capabilities of member agencies and to help them work together to prevent and reduce air pollution impacts in the Mid-Atlantic Region.

MARAMA provides cost-effective approaches to regional collaboration by pooling resources to develop and analyze data, share ideas, and train staff to implement common requirements.

The following State and Local governments are MARAMA members: Delaware, the District of Columbia, Maryland, New Jersey, North Carolina, Pennsylvania, Virginia, West Virginia, Philadelphia, and Allegheny County, Pennsylvania.

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Development of Emission Projections for 2009, 2012, and 2018 for NonEGU Point, Area, and Nonroad Sources in the MANE-VU Region

Final Technical Support Document

Prepared for:

Mid-Atlantic Regional Air Management Association (MARAMA)

Prepared by:

MACTEC Federal Programs, Inc.

February 28, 2007

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Principal Scientist	Principal Engineer

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Acronyms and Abbreviations

Acronym	**Description**
AEO	Annual Energy Outlook
BOTW	Beyond-on-the-Way emission controls
CAIR	Clean Air Interstate Rule
EGAS 5.0	Economic Growth Analysis System Version 5.0
EGU	Electric Generating Unit
EIA	Energy Information Agency
EPA	U.S. Environmental Protection Agency
IDA	Inventory Data Analyzer (data format used by SMOKE modeling system)
IPM	Integrated Planning Model
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MARAMA	Mid-Atlantic Regional Air Management Association
MOBILE6	U.S. EPA's emission model for onroad sources
NESCAUM	Northeast States for Coordinated Air Use Management
NH3	Ammonia
NIF3.0	National Emission Inventory Input Format Version 3.0
NMIM	National Mobile Inventory Model
NONROAD	U.S. EPA's emission model for certain types of nonroad equipment
NOx	Oxides of nitrogen
OTB/OTW	On-the-Books/On-the-Way
OTC	Ozone Transport Commission
PM10-PRI	Particulate matter less than or equal to 10 microns in diameter that includes both the filterable and condensable components of particulate matter
PM25-PRI	Particulate matter less than or equal to 2.5 microns in diameter that includes both the filterable and condensable components of particulate matter
SIC	Standard Industrial Classification code
SIP	State Implementation Plan
SCC	Source Classification Code
SMOKE	Sparse Matrix Operator Kernel Emissions Modeling System
SO2	Sulfur dioxide
VOC	Volatile organic compounds

1.0 EXECUTIVE SUMMARY

This report was prepared for the Mid-Atlantic Regional Air Management Association (MARAMA) as part of an effort to assist states in developing State Implementation Plans (SIPs) for ozone, fine particles, and regional haze. It describes the data sources, methods, and results for emission forecasts for three years, three emission sectors, two emission control scenarios; seven pollutants, and 11 states plus the District of Columbia. The following is a summary of the future year inventories that were developed:

- The three projection years are 2009, 2012, and 2018.
- The three source sectors are non-Electric Generating Units (non-EGUs), area sources, and nonroad mobile sources. (Note: under separate efforts, MANE-VU prepared EGU projections using the Integrated Planning Model {IPM} and onroad mobile source projections using the SMOKE emission modeling system).
- The two emission control scenarios are: a) a combined “on-the-books/on-the-way” (OTB/W) control strategy accounting for emission control regulations already in place as well as emission control regulations that are not yet finalized but are likely to achieve additional reductions by 2009; and b) a “beyond-on-the-way” (BOTW) scenarios to account for controls from potential new regulations that may be necessary to meet attainment and other regional air quality goals.
- The seven pollutants are sulfur dioxide (SO2), oxides of nitrogen (NOx), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter less than or equal to 10 microns in diameter that includes both the filterable and condensable components of particulate matter (PM10-PRI), particulate matter less than or equal to 2.5 microns in diameter that includes both the filterable and condensable components of particulate matter (PM25-PRI), and ammonia (NH3).
- The states are those that comprise the Mid-Atlantic/Northeast Visibility Union (MANE-VU) region. In addition to the District of Columbia, the 11 MANE-VU states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

The results of the emission projections are summarized in Table 1-1 and Figures 1-1 to 1-7.

Section 2 of this report describes how the nonEGU OTB/W emission projections were made. Section 3 describes the methods for the area source emission projections. Section 4 describes the methods for the nonroad section, including sources accounted for by the NONROAD model as well as aircraft, locomotives, and marine vessels. Section 5 describes the development of the BOTW emission projections.

Table 1-1 Summary of MANE-VU Area, NonEGU, and Nonroad Emission Inventory by Pollutant, Sector, and Year Annual Emissions (tons per year)

Pollutant	Sector	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CO	Area	1,326,796	1,283,959	1,283,959	1,260,627	1,260,627	1,211,727	1,211,727
	NonEGU	295,577	328,546	328,546	346,090	346,090	412,723	412,723
	Nonroad	4,553,124	4,969,925	4,969,925	5,099,538	5,099,538	5,401,353	5,401,353
		6,175,497	6,582,430	6,582,430	6,706,255	6,706,255	7,025,803	7,025,803
NH3	Area	249,795	294,934	294,934	312,419	312,419	341,746	341,746
	NonEGU	3,916	4,301	4,301	4,448	4,448	4,986	4,986
	Nonroad	287	317	317	337	337	369	369
		253,998	299,552	299,552	317,204	317,204	347,101	347,101
NOx	Area	265,400	278,038	265,925	281,659	261,057	284,535	263,030
	NonEGU	207,048	210,522	185,658	218,137	184,527	237,802	199,732
	Nonroad	431,631	354,850	354,850	321,935	321,935	271,185	271,185
		904,079	843,410	806,433	821,731	767,519	793,522	733,947
PM10	Area	1,452,309	1,527,586	1,527,586	1,556,316	1,550,400	1,614,476	1,607,602
	NonEGU	51,280	55,869	55,869	57,848	57,624	63,757	63,524
	Nonroad	40,114	34,453	34,453	32,445	32,445	27,059	27,059
		1,543,703	1,617,908	1,617,908	1,646,609	1,640,469	1,705,292	1,698,185
PM2.5	Area	332,521	340,049	340,049	341,875	336,779	345,419	339,461
	NonEGU	33,077	36,497	36,497	37,625	37,444	41,220	41,029
	Nonroad	36,084	30,791	30,791	28,922	28,922	23,938	23,938
		401,682	407,337	407,337	408,422	403,145	410,577	404,428
SO2	Area	286,921	304,018	304,018	305,339	202,058	305,437	190,431
	NonEGU	264,377	249,658	249,658	255,596	253,638	270,433	268,330
	Nonroad	57,257	15,651	15,651	8,731	8,731	8,643	8,643
		608,555	569,327	569,327	569,666	464,427	584,513	467,404
VOC	Area	1,528,269	1,398,982	1,363,278	1,382,803	1,339,851	1,387,882	1,334,039
	NonEGU	91,278	92,279	91,718	96,887	96,260	110,524	109,762
	Nonroad	572,751	460,922	460,922	424,257	424,257	380,080	380,080
		2,192,298	1,952,183	1,915,918	1,903,947	1,860,368	1,878,486	1,823,881

OTB/W – on-the-books/way scenario; BOTW – beyond-on-the-way scenario

Figure 1-1 2002 Base Year, OTB/OTW AND BOTW Annual CO Emissions (tons per year)

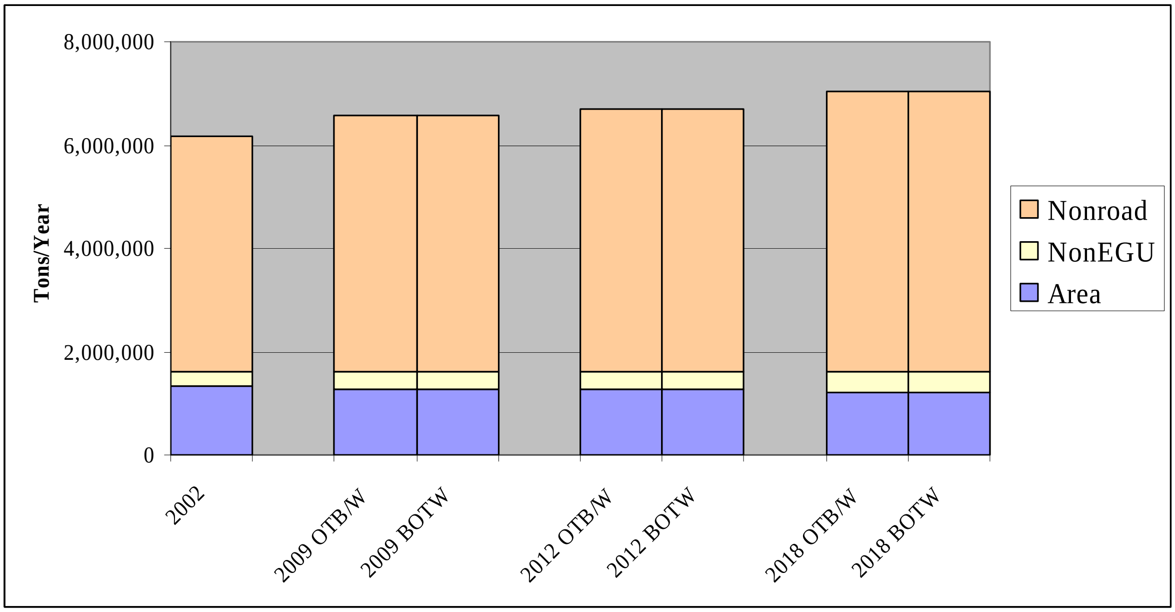


Figure 1-2 2002 Base Year, OTB/OTW AND BOTW Annual NH3 Emissions (tons per year)

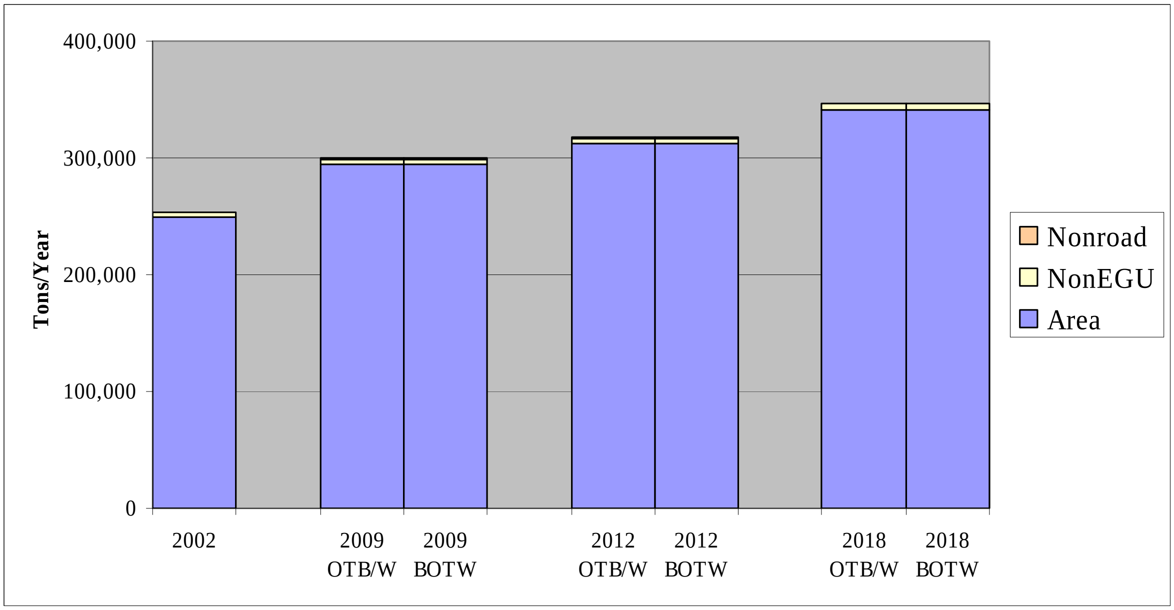


Figure 1-3 2002 Base Year, OTB/OTW AND BOTW Annual NOx Emissions (tons per year)

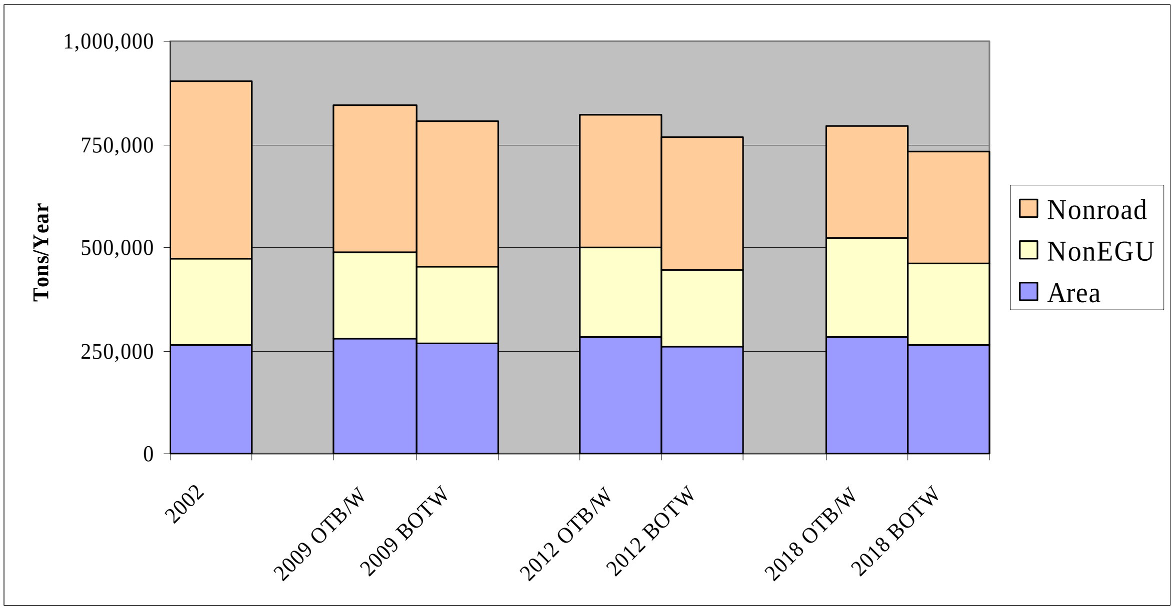


Figure 1-4 2002 Base Year, OTB/OTW AND BOTW Annual SO2 Emissions (tons per year)

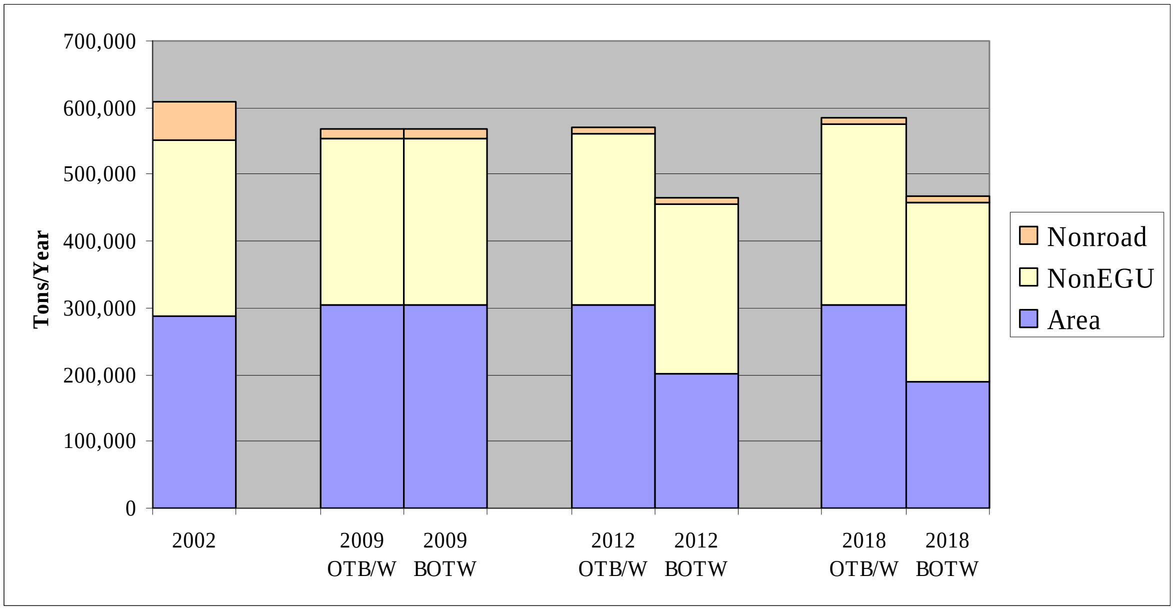


Figure 1-5 2002 Base Year, OTB/OTW AND BOTW Annual PM10 Emissions (tons per year)

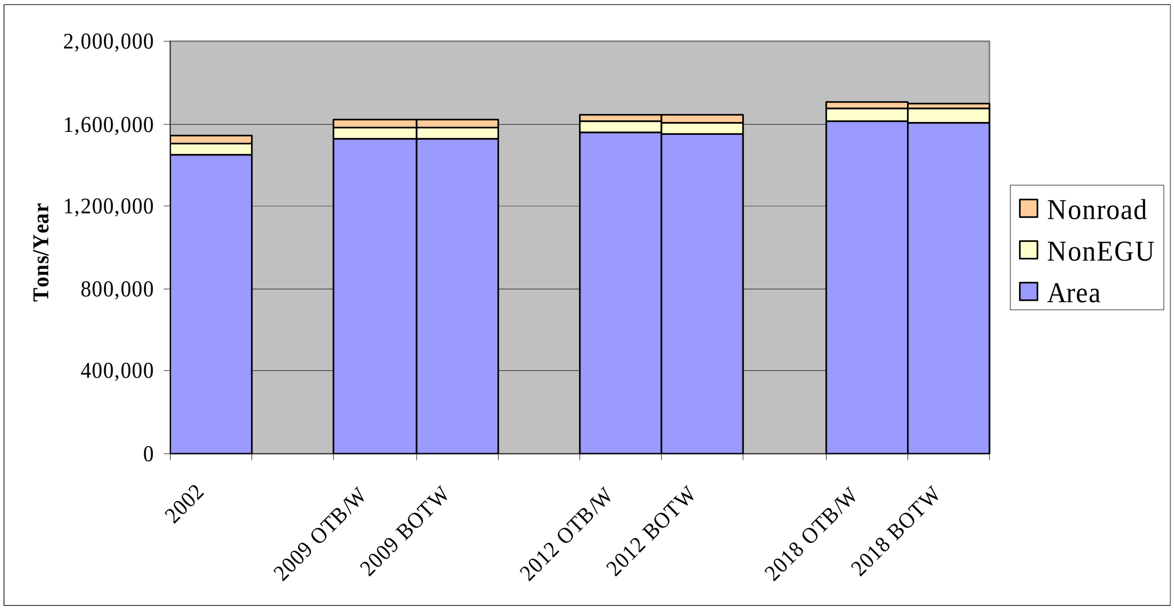


Figure 1-6 2002 Base Year, OTB/OTW AND BOTW Annual PM2.5 Emissions (tons per year)

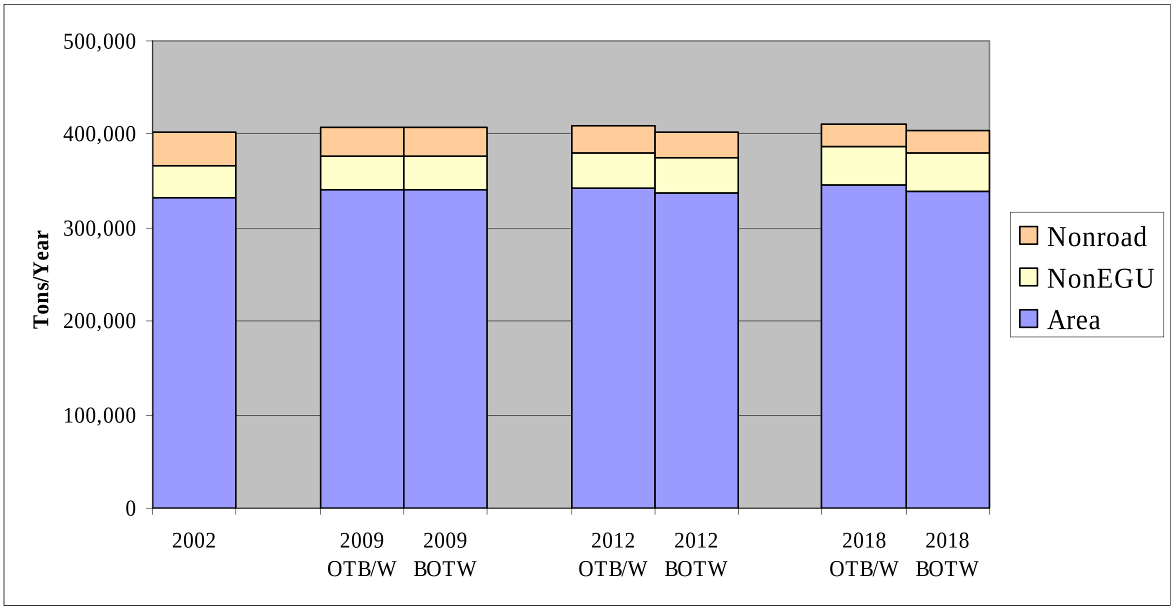
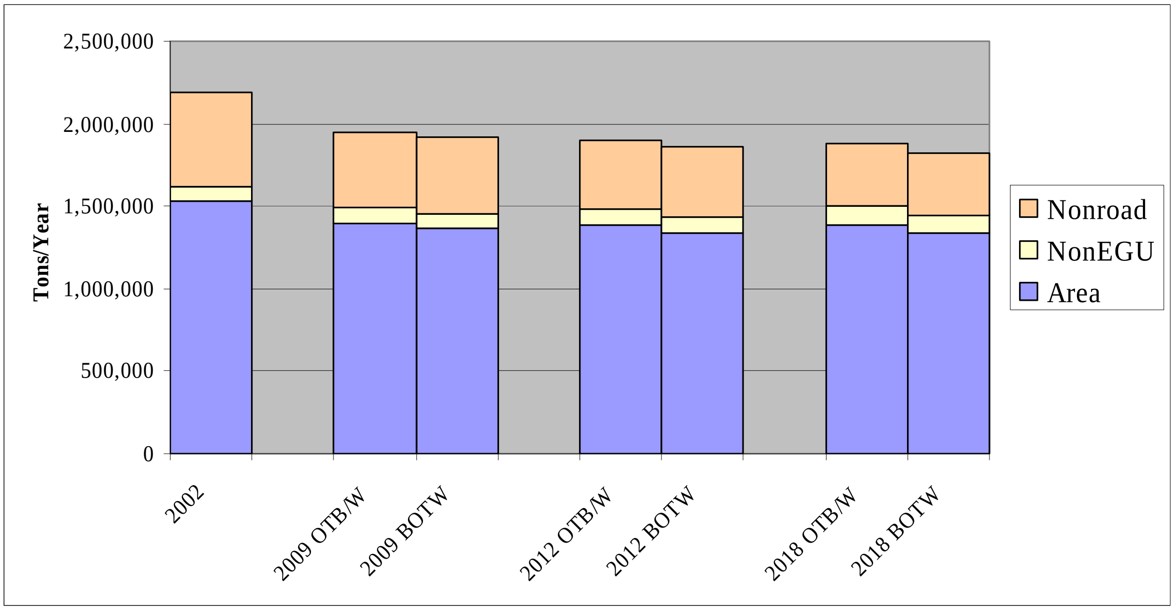


Figure 1-7 2002 Base Year, OTB/OTW AND BOTW Annual VOC Emissions (tons per year)



2.0 NONEGU POINT SOURCES

Under ideal circumstances, all stationary sources would be considered point sources for purposes of emission inventories. In practical applications, however, only sources that emit more than a specified cutoff level of pollutant are considered point sources. In general, the MANE-VU point source inventory includes only major sources (i.e., those required to obtain a Title V operating permit). Some states may include additional stationary sources that emit below the major source thresholds.

For emission projection purposes, the point source inventory is divided into two sub-sectors – the Electric Generating Unit (EGU) sector and the non-EGU sector – because different projections methods are used for these two sectors. For EGUs, MANE-VU used the Integrated Planning Model (IPM) to project future generation as well as to calculate the impact of future control programs on future emission levels.

The procedures for projecting emissions for non-EGUs are described in this section. We started with the MANE-VU 2002 point source emission inventory, which contains data for both EGUs and nonEGUs. We implemented a procedure to split the 2002 point source inventory into two components – and EGU inventory for those units accounted for in IPM, and a nonEGU inventory for those point sources not accounted for in IPM. For the nonEGU sources, we first applied growth factors to account for changes in economic activity. Next, we applied control factors to account for future emission reductions from on-the-books (OTB) control regulations and on-the-way (OTW) control regulations. The OTB control scenario accounts for post-2002 emission reductions from promulgated federal, State, local, and site-specific control programs as of June 15, 2005. The OTW control scenario accounts for proposed (but not final) control programs that are reasonably anticipated to result in post-2002 emission reductions. We then conducted a series of quality assurance steps to ensure the development of complete, accurate, and consistent emission inventories. We provided the inventories in three formats – the National Emission Inventory Input Format (NIF), SMOKE Inventory Data Analyzer (IDA) format, and SMOKE growth/control packets. We also prepared emission summary tables by state and pollutant. Each of these activities is discussed in this section.

2.1 INITIAL 2002 POINT SOURCE EMISSION INVENTORY

The starting point for the nonEGU projections was Version 3 of the MANE-VU 2002 point source emission inventory (MANE-VU_2002_Pt_Version 3_040706.MDB). Since this file contains both EGUs and nonEGU point sources, and EGU emissions are projected using the IPM, it was necessary to split the 2002 point source file into two components.

The first component contains those emission units accounted for in the IPM forecasts. The second component contains all other point sources not accounted for in IPM.

The MANE-VU 2002 point source inventory contains a cross-reference table (xwalk {MANE-VU}) that matches IPM emission unit identifiers (ORISPL plant code and BLRID emission unit code) to MANE-VU NIF emission unit identifiers (FIPSST state code, FIPSCNTY county code, State Plant ID, State Point ID). Initially, we used this cross-reference table to split the point source file into the EGU and nonEGU components. When there was a match between the IPM ORISPL/BLRID and the MANE-VU emission unit ID, the unit was assigned to the EGU inventory; all other emission units were assigned to the nonEGU inventory. The exception to this rule was for the State of New York. The cross-reference table only contained matches at the plant level, not the emission unit level. So for New York EGUs accounted for in IPM, all emission units at a plant were assigned to the MANE-VU EGU file (including ancillary emission units not accounted for in IPM).

After performing this initial splitting of the MANE-VU point source inventory into EGU and nonEGU components, we prepared several ad-hoc QA/QC queries to verify that there was no double-counting of emissions in the EGU and nonEGU inventories:

- We reviewed the IPM parsed files {VISTASII_PC_1f_AllUnits_2009 (To Client).xls and VISTASII_PC_1f_AllUnits_2018 (To Client).xls} to identify EGUs accounted for in IPM. We compared this list of emission units to the nonEGU inventory derived from the MANE-VU cross-reference table to verify that units accounted for in IPM were not double-counted in the nonEGU inventory. As a result of this comparison, we made a few adjustments in the cross-reference table to add emission units for four plants to ensure these units accounted for in IPM were moved to the EGU inventory.

- We reviewed the nonEGU inventory 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”. We compared the list of sources meeting these selection criteria to the IPM parsed file to ensure that these units were not double-counted.

- We compared the number of records for each NIF table in the original 2002 point source file to the 2002 EGU and 2002 nonEGU files. We determined that the sum of the number of records in the EGU file and the number of records in the nonEGU file equaled the number of records in the original 2002 point source file.

- We compared the emissions by pollutant and state in the original 2002 point source file to the 2002 EGU file and 2002 nonEGU files. We determined that the sum of the emissions in the EGU file and the emissions in the nonEGU file equaled the emissions in the original 2002 point source file.

As a result of this procedure, we created separate sets of NIF tables for 2002 for EGUs (i.e., units accounted for in IPM) and nonEGUs. The nonEGU set of 2002 NIF tables were used in all subsequent projections for 2009/2012/2018.

After release of Version 3 of the MANE-VU 2002 inventory, New Jersey discovered that fugitive emissions from petroleum refineries were missing from Version 3. New Jersey supplied MACTEC with the emission unit identifiers for the fugitive releases, and the appropriate records were added to the 2002 NIF files.. MACTEC used these revised fugitive estimates for projecting emissions to 2009/2012/2018.

2.2 NONEGU POINT SOURCE GROWTH FACTORS

The nonEGU growth factors were developed using three sets of data:

- The U.S. EPA’s Economic Growth and Analysis System Version 5.0 (EGAS 5.0) using the default SCC configuration. EGAS 5.0 generates growth factors from REMI’s 53 Sector Policy Insight Model Version 5.5, the U.S. Department of Energy (DOE) Annual Energy Outlook 2004 (AEO2004) fuel use projections, and national vehicle mile travel projections from EPA’s MOBILE 4.1 Fuel Combustion Model;

- The DOE’s Annual Energy Outlook 2005 (AEO2005) fuel consumption forecasts were used to replace the AEO2004 forecasts that are used as the default values in EGAS 5.0; and

- State-supplied population, employment, and other emission projection data.

The priority for applying these growth factors was to first use the state-supplied projection data (if available). If no state-supplied data are available, then we used the AEO2005 projection factors for fuel consumption sources. If data from these two sources were not available, we used the EGAS 5.0 default SCC configuration. Appendix A lists the nonEGU point source growth factors used for this study.

2.2.1 EGAS 5.0 Growth Factors

EGAS is an EPA-developed economic and activity forecast tool that provides credible growth factors for developing emission inventory projections. Growth factors are generated using national- and regional-economic forecasts. For nonEGUs, the primary economic activity data sets in EGAS 5.0 are:

- State-specific growth rates from the Regional Economic Model, Inc. (REMI) Policy Insight® model, version 5.5. The REMI socioeconomic data (output by industry sector, population, farm sector value added, and gasoline and oil expenditures) are available by 4-digit SIC code at the State level.
- Energy consumption data from the DOE's Energy Information Administration's (EIA) *Annual Energy Outlook 2004, with Projections through 2025* for use in generating growth factors for non-EGU fuel combustion sources. These data include regional or national fuel-use forecast data that were mapped to specific SCCs for the non-EGU fuel use sectors (e.g., commercial coal, industrial natural gas). Growth factors are reported at the Census division level. These Census divisions represent a group of States (e.g., the South Atlantic division includes Delaware, the District of Columbia, and Maryland; the Middle Atlantic division includes New Jersey, New York, and Pennsylvania; the New England division includes Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont). Although one might expect different growth rates in each of these States due to unique demographic and socioeconomic trends, all States within each division received the same growth rate.

EGAS uses these economic activity datasets and a set of cross-reference files to generate growth factors by Standard Industrial Classification (SIC) code, Source Classification Code (SCC), or Maximum Achievable Control Technology (MACT) codes. Growth factors for 2009, 2012, and 2018 were calculated using 2002 as the base year at the State and SCC level. County-specific growth factors are not available in EGAS 5.0.

There were several SCCs in the MANE-VU 2002 inventory that are not included in the EGAS 5.0 files. As a result, EGAS did not generate growth factors for those SCCs. MACTEC assigned growth factors for the missing SCCs by assigning a surrogate SCC that best represented the missing SCC.

2.2.2 AEO2005 Growth Factors

The default version of EGAS 5.0 uses the DOE's AEO2004 forecasts. We replaced these data with the more recent AEO2005 forecasts to improve the emissions growth factors produced. Using ACCESS, we created a copy of the "DOE EGAS 5" dataset. The dataset includes three tables. One table contains the projection data values from 2001-2025. The other two tables are the MACT and SCC crosswalk tables. The crosswalk tables are linked to the projection table via a "model code". Using the copy of AEO2004 data, we updated the corresponding projection tables with data from the AEO2005 located at: http://www.eia.doe.gov/oiaf/aeo/supplement/supref.html . Using the data and descriptions from the new tables, we matched the projection data to the appropriate model codes and then built a table identical to the DOE EGAS 5 dataset with the new 2005 AEO data. The resulting ACCESS dataset contains a projection data table with the exact same structure as the original except with the new data. The SCC and MACT crosswalks did not require any updates since the model code assignments were not changed in the new data table.

2.2.3 State Specific Growth Factors

In addition to the growth data described above, we received growth projections from several MANE-VU states to be used instead of the default EGAS or AEO2005 growth factors. The following paragraphs describe the growth factors used for each state.

2.2.3.1 Connecticut

Connecticut provided state-level employment-based growth factors for various SIC categories derived from CT Department of Labor (CTDOL) projections. For many manufacturing sectors, employment is projected to decline, indicating the likelihood of reduced activity levels and emissions for those sectors. Associated growth factors are less than one. To ensure consistency within a facility, CTDEP indicated that the employment-based growth factors be used wherever possible, as matched by SIC. MACTEC used the growth factors by SIC code for all sources in CT, including those fuel combustion sources that would otherwise have been projected using the AEO2005 forecasts.

2.2.3.2 Delaware

Delaware provided state-level employment data from the Department of Labor by NAICS codes for 2002 and 2012. We used these data to calculate the growth factor from 2002 to 2012 and interpolated these data to derive growth factors for 2009 and 2018. We matched these industry NAICS groupings to SCC codes in order to create SCC specific growth factors for non-EGU point sources.

2.2.3.3 District of Columbia

DC indicated that it preferred to use the EGAS 5.0 growth factors, with the enhancement of using the DOE's 2005 Annual Energy Outlook data for combustion sources.

2.2.3.4 Maine

Maine indicated that it preferred to use the EGAS 5.0 growth factors and the DOE's 2005 Annual Energy Outlook data for combustion sources.

2.2.3.5 Maryland

Maryland provided growth factors by SCC for all counties in the State. These growth factors were derived from a variety source sources, including the MWCOG Cooperative Forecast 7.0, the BMC Round 6A Cooperative Forecast (prepared by the MD Dept. of Planning, May 2004), and EGAS 5.0.

2.2.3.6 Massachusetts

Massachusetts also provided a link to employment projections for 2000-2010 for very narrow occupational categories that are not directly correlated with SIC or SCC codes. Since we could not match the occupational titles in the Massachusetts employment projections with SIC or SCC codes, MACTEC used the EGAS 5.0 growth factors (with the AEO2005 enhancement for combustion sources) for projecting emissions from nonEGU sources.

2.2.3.7 New Hampshire

New Hampshire indicated that it preferred to use the EGAS 5.0 growth factors, with the enhancement of using the DOE’s 2005 Annual Energy Outlook data for combustion sources.

2.2.3.8 New Jersey

New Jersey indicated that it preferred to use the EGAS 5.0 growth factors, with the enhancement of using the DOE’s 2005 Annual Energy Outlook data for combustion sources.

2.2.3.9 New York

New York provided county-level employment data for 12 counties in the New York City metro area for 2002, 2009, 2012, and 2018. The employment projections are for broad industry categories not directly correlated with SIC or SCC codes. Since we could not match the 12-county employment projections with SIC or SCC codes, MACTEC used the EGAS 5.0 growth factors (with the AEO2005 enhancement for combustion sources) for projecting emissions from nonEGU sources for both the 12-county area and all other counties in the state.

2.2.3.10 Pennsylvania

Pennsylvania provided total employment projections for a subset of counties. These employment projections do not have enough detail regarding specific industrial groupings to be correlated with SIC or SCC codes. MACTEC used the EGAS 5.0 growth factors (with the AEO2005 enhancement for combustion sources) for projecting emissions from nonEGU sources

2.2.3.11 Rhode Island

Rhode Island provided state-level employment data from the Department of Labor and Training by 3-digit NAICS codes for 2002 and 2012. We used these data to calculate the growth factor from 2002 to 2012 and interpolated these data to derive growth factors for 2009 and 2018. We matched these industry NAICS groupings to SCC codes in order to create SCC specific growth factors for non-EGU point sources.

2.2.3.12 Vermont

Vermont indicated that it preferred to use the EGAS 5.0 growth factors, with the enhancement of using the DOE's 2005 Annual Energy Outlook data for combustion sources.

2.3 NONEGU POINT SOURCE CONTROL FACTORS

The following sections document how the OTB/OTW control factors were developed for the MANE-VU future year inventories. We developed control factors to estimate emission reductions that will result from on-the-books regulations that will result in post-2002 emission reductions and proposed regulations or actions that will result in post-2002 emission reductions. Control factors were developed for the following national, regional, or state control measures:

- NOx SIP Call Phase I (NOx Budget Trading Program)
- NOx SIP Call Phase II
- NOx RACT in 1-hour Ozone SIPs
- NOx OTC 2001 Model Rule for ICI Boilers
- 2-, 4-, 7-, and 10-year MACT Standards
- Combustion Turbine and RICE MACT
- Industrial Boiler/Process Heater MACT
- Refinery Enforcement Initiative
- Source Shutdowns

In addition, states provided specific control measure information about specific sources or regulatory programs in their state. We used the state-specific data to the extent it was available.

2.3.1 NOx SIP Call Phase I

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

Cement kilns were also included in Phase I of the NO_x SIP call. There is a cement kiln in Maine, but it is not subject to the NOx SIP call. For the cement kilns in Maryland and New York, a default control efficiency value of 25 percent was applied. For the cement kilns in Pennsylvania, the state provided their best estimates of the actual control efficiency expected for each kiln after the NOx SIP Call. Table B-2 identifies the cement kilns affected by the NOx SIP Call.

2.3.2 NOx SIP Call Phase II

The final Phase II NOx SIP Call rule was promulgated on April 21, 2004. States had until April 21, 2005, to submit SIPs meeting the Phase II NOx budget requirements. The Phase II rule applies to large IC engines, which are primarily used in pipeline transmission service at compressor stations. We have identified affected units using the same methodology as was used by EPA in the proposed Phase II rule (i.e., a large IC engine is one that emitted, on average, more than 1 ton per day during 2002). The final rule reflects a control level of 82 percent for natural gas-fired IC engines and 90 percent for diesel or dual fuel categories. Pennsylvania identified large IC engines affected by the rule. Table B-3 identifies those units included in the NOx SIP Call Phase II.

2.3.3 NOx RACT in 1-hour Ozone SIPs

Emission reductions requirements from NOx reasonably available control technology (RACT) requirements in 1-hour Ozone SIP areas were implemented in or prior to 2002.

These reductions should already be accounted for in the MANE-VU 2002 inventory since the 2002 inventory was based on 2002 actual emissions which includes any reductions due to NOx RACT.

2.3.4 NOx OTC 2001 Model Rule for ICI Boilers

The Ozone Transport Commission (OTC) developed control measures for industrial, commercial, and institutional (ICI) boilers in 2001. Information about the proposed OTC NOx emission limits by fuel type and size range was obtained from Table III-1 of *Control Measure Development Support Analysis of Ozone Transport Commission Model Rules* (E.H. Pechan & Associates, Inc., March 31, 2001). Information about the emission limits contained in the existing state rules (prior to adoption of the OTC 2001 model rule) were obtained from Tables III-2 through III-9 of the Pechan document. Information about the emission limits contained in the current state rules (as they existed in June 2006) were obtained from the individual states regulations. The percent reduction for ICI boilers was estimated by state, fuel type, and size range by comparing the current state emission limits (as they existed in June 2006) with the state emission limits as they existed in 2001. Pennsylvania adopted the OTC 2001 model rule in five southeastern counties (Bucks, Chester, Delaware, Montgomery, and Philadelphia) for boilers in the 100 to 250 million Btu/hour range. New Jersey adopted the OTC 2001 model rule for natural gas-fired boilers with a maximum heat rate of at least 100 million Btu/hour. For other states, it did not appear that the emission limits in 2006 had changed from the emission limits in 2001.

2.3.5 2-, 4-, 7-, and 10-year MACT Standards

Maximum achievable control technology (MACT) requirements were also applied, as documented in the report entitled *Control Packet Development and Data Sources*, dated July 14, 2004 (available at http://www.epa.gov/air/interstateairquality/pdfs/Non-EGU_nonpoint_Control_Development.pdf). The point source MACTs and associated emission reductions were designed from Federal Register (FR) notices and discussions with EPA's Emission Standards Division (ESD) staff. These MACT requirements apply only to units located at a major source of hazardous air pollutants (HAP). We did not apply reductions for MACT standards with an initial compliance date of 2002 or earlier, assuming that the effects of these controls are already accounted for in the inventories supplied by the States. Emission reductions were applied only for MACT standards with an initial compliance date of 2003 or greater.

Because the MANE-VU inventory does not identify HAP major sources, the reductions from post-2002 MACT standards were applied on a more general scale to all sources with certain SCCs. Every source with an SCC determined to be affected by a post-2002 MACT standard was assigned an incremental percent reduction for the applicable MACT standard. Table B-4 shows the SCCs affected and the incremental control efficiencies applied for post-2002 MACT standards.

2.3.6 Combustion Turbine and RICE MACT

The MANE-VU projection inventory does not include the NOx co-benefit effects of the MACT regulations for Gas Turbines or stationary Reciprocating Internal Combustion Engines, which EPA estimates to be small compared to the overall inventory.

2.3.7 Industrial Boiler/Process Heater MACT

EPA anticipates ancillary reductions in PM and SO2 as a result of the Industrial Boiler/Process Heater MACT standard. The MACT applies to industrial, commercial, and institutional units firing solid fuel (coal, wood, waste, biomass) which have a design capacity greater than 10 mmBtu/hr and are located at a major source of hazardous air pollutants (HAP). The boiler design capacity field in many cases was missing from the MANE-VU emission inventory. In lieu of boiler design capacity, we identified boilers with the following SCCs that emitted greater than 10 tons/year of either SO2 or PM10

- 1-02-001-xx Industrial, Anthracite Coal
- 1-02-002-xx Industrial, Bituminous/subbituminous Coal
- 1-02-008-xx Industrial, Petroleum Coke
- 1-02-009-xx Industrial, Wood/Bark Waste
- 1-03-001-xx Commercial/Institutional, Anthracite Coal
- 1-03-002-xx Commercial/Institutional, Bituminous/subbituminous Coal
- 1-03-009-xx Commercial/Institutional, Wood/Bark Waste
- 3-90-002-89 In-Process Fuel Use, Bituminous Coal
- 3-90-002-99 In-Process Fuel Use, Bituminous Coal
- 3-90-008-89 In-Process Fuel Use, Coke
- 3-90-008-99 In-Process Fuel Use, Coke
- 3-90-009-99 In-Process Fuel Use, Wood

For these sources, we applied the average MACT control efficiencies of 4% for SO2 and 40% for PM.

2.3.8 Refinery Enforcement Initiative

Both EPA and State/local agencies have negotiated (or are in the process of negotiating) Consent Decrees that will require significant investment in pollution control technology and will result in significant emission reductions in the future. There are eight refineries in the MANE-VU inventory impacted by the settlements. The five major refinery processes that are affected by the judicial settlements are:

- Fluid Catalytic Cracking Units (FCCUs) and Fluid Coking Units (FCUs)
- Process Heaters and Boilers
- Flare Gas Recovery
- Leak Detection and Repair
- Benzene/Wastewater

As part of the development of the *Assessment of Control Technology Options for Petroleum Refineries in the Mid-Atlantic Region* (Draft Final, October 2006), MACTEC coordinated with State and local agencies to develop estimates of future year emissions based upon the settlements and recent permits that implement the provisions of those settlements.

For FCCUs/FCUs, the Consent Decree control requirements generally require the installation of wet gas scrubbers for SO2 control. Some of the units have already been permitted to include the control requirements. In those cases, specific emission limits for SO2 have already been established and were used as the best estimate of emission in 2009. In cases where specific emission limitation have not yet been specified in permits, a 90 percent SO2 control efficiency was assumed as a conservative estimate of the SO2 reductions from the installation of a wet gas scrubber.

For NOx control at FCCUs/FCUs, the Consent Decrees require selective catalytic reduction (SCR), selective non-catalytic reduction (SCNR), or optimization studies to reduce NOx emissions. Some of the units have already been permitted to include the control requirements. In those cases, specific emission limits for NOx have already been established and were used as the best estimate of emission in 2009. In cases where specific emission limitation have not yet been specified in permits, a 90 percent NOx control efficiency was assumed for SCR, and a 60 percent reduction was assumed from the installation of SNCR.

For SO2 emissions from boilers/heaters, the control requirements generally require the elimination of burning solid/liquid fuels. We identified all boilers and heaters at the eight affected refineries that burn solid or liquid fuels. For these units, we set the SO2 emissions to zero in the future year inventories.

For NOx emissions from boilers/heaters, control requirements generally apply to units greater than 40 million British thermal units (MMBtu) per hour capacity or larger. In many cases, the consent decrees establish NO_x emission reduction objectives across a number of refineries that are owned by the same firm. Therefore, the companies have some discretion in deciding which individual boilers/heaters to control as well as the control techniques to apply. Also, the consent decrees have various phase-in dates which make it difficult to determine the exact date when the reductions will be fully realized. As part of the development of the *Assessment of Control Technology Options for Petroleum Refineries in the Mid-Atlantic Region* (Draft Final, October 2006), MACTEC coordinated with State and local agencies to develop estimates of future year emissions based upon the settlements and recent permits that implement the provisions of those settlements. Heater/boiler NOx controls for the units to which they are applied were determined to be equivalent to meeting a 0.04 lbs per million Btu NOx emission rate. Meeting this emission reduction requirement is expected to provide an average NOx emission reduction of 50 percent from 2002 levels in 2009.

The Consent Decrees also included enhanced LDAR programs (e.g., reducing the defined leak concentration, increasing the monitoring frequency, other requirements. Our best estimate is a 50% reduction in VOC emissions as a result of implementing enhanced LDAR programs similar to those required in the recent Consent Decrees. This is based on a study (http://www.rti.org/pubs/ertc_enviro_2002_final1.pdf) that estimated an enhanced LDAR program could result in a 50% reduction in fugitive VOCs.

The settlements are expected to produce additional SO2, NOx, and VOC emission reductions for flare gas recovery and wastewater operations. These emission reductions were not quantified as they are expected to produce less significant changes in the MANE-VU inventory because of the magnitude and uncertainty associated with the emissions from these units in the 2002 MANE-VU inventory.

2.3.9 Source Shutdowns

A few states indicated that significant source shutdowns have occurred since 2002 and that emissions from these sources should not be included in the future year inventories. These sources are identified in Table B-5.

2.3.10 State Specific Control Factors

Delaware provided reductions expected from the Maritrans lightering operation. VOC emissions are projected to be reduced by 34.8% by 2009, 69.3% by 2012, and 79.2% by 2018.

2.4 NONEGU POINT SOURCE QA/QC REVIEW

Throughout the inventory development process, quality assurance steps were performed to ensure that no double counting of emissions occurred, and to ensure that a full and complete inventory was developed. Quality assurance was an important component to the inventory development process and MACTEC performed the following QA steps on the nonEGU point source component of the MANE-VU future year inventories:

1. State agencies reviewed the draft growth and control factors in the summer of 2005. Changes based on these comments were implemented in the files.
2. Compared, at the emission unit-level, emissions from the IPM parsed files and the MANE-VU NIF files to verify that the splitting of the MANE-VU point source inventory into the EGU and nonEGU sectors did not result in any double county of emissions or cause units to be missing from both inventories.
3. SCC level emission summaries were prepared and evaluated to ensure that emissions were consistent and that there were no missing sources. Tier comparisons (by pollutant) were developed between the revised 2002 base year inventory and the 2009/2012/2018 projection inventories.
4. State level emission summaries were prepared and evaluated to ensure that emissions were consistent and reasonable. The summaries included base year 2002 emissions, 2009/2012/2018 projected emissions accounting only for growth, 2009/2012/2018 projected emissions accounting for both growth and emission reductions from OTB and OTW controls.
5. Emission inventory files in NIF format were provided for state agency review and comment. Changes based on these comments were implemented.
6. All final files were run through EPA's Format and Content checking software.
7. Version numbering was used for all inventory files developed. The version numbering process used a decimal system to track major and minor changes. For example, a major change would result in a version going from 1.0 to 2.0 for example. A minor change would cause a version number to go from 1.0 to 1.1. Minor changes resulting from largely editorial changes would result in a change from 1.00 to 1.01 for example.

Final QA checks were run on the revised projection inventory data set to ensure that all corrections provided by the S/L agencies and stakeholders were correctly incorporated into the S/L inventories and that there were no remaining QA issues that could be addressed during the duration of the project. After exporting the inventory to ASCII text files in NIF 3.0, the EPA QA program was run on the ASCII files and the QA output was reviewed to verify that all QA issues that could be addressed were resolved

2.5 NONEGU POINT SOURCE NIF AND SMOKE FILES

The Version 3 file names and descriptions delivered to MARAMA are shown in Table 2-1.

2.6 NONEGU POINT SOURCE EMISSION SUMMARIES

Emission summaries by state, year, and pollutant are presented in Tables 2-2 through 2-8 for CO, NH3, NOx, PM10-PRI, PM25-PRI, SO2, and VOC, respectively.

Table 2-1 NonEGU Point Source NIF, IDA, and Summary File Names

File Name	Date	Description
MANEVU_OTB2009_NonEGU_NIFV3_1.mdb	Dec. 4, 2006	Version 3.1 of 2009 OTB NonEGU source NIF inventory
MANEVU_OTB2012_NonEGU_NIFV3_1.mdb	Dec. 4, 2006	Version 3.1 of 2012 OTB NonEGU source NIF inventory
MANEVU_OTB2018_NonEGU_NIFV3_1.mdb	Dec. 4, 2006	Version 3.1 of 2018 OTB NonEGU source NIF inventory
MANEVU_OTB2009_NonEGU_IDAV3_1.txt	Nov. 22, 2006	Version 3.1 of 2009 OTB NonEGU source inventory in SMOKE IDA format
MANEVU_OTB2012_NonEGU_IDAV3_1.txt	Nov. 22, 2006	Version 3.1 of 2012 OTB NonEGU source inventory in SMOKE IDA format
MANEVU_OTB2018_NonEGU_IDA3V_2.txt	Nov. 22, 2006	Version 3.1 of 2018 OTB NonEGU source inventory in SMOKE IDA format
MANEVU OTB BOTW NonEGU V3_1 State Summary.xls	Nov. 22, 2006	Spreadsheet with state totals by pollutant for all NonEGU sources
MANEVU OTB BOTW NonEGU V3_1 State SCC Summary.xls	Dec. 4, 2006	Spreadsheet with SCC totals by state and pollutant for all NonEGU sources.

Table 2-2 NonEGU Point Sources
OTB/OTW Annual CO Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	2,157	2,251	2,306	2,415
DE	8,812	9,037	8,748	8,651
DC	247	283	299	327
ME	9,043	10,147	10,467	11,433
MD	94,536	104,012	111,174	141,342
MA	10,793	12,027	12,552	13,426
NH	774	858	871	907
NJ	8,209	10,076	10,806	12,244
NY	53,259	61,411	65,541	78,876
PA	105,815	116,430	121,251	140,909
RI	1,712	1,764	1,821	1,927
VT	220	250	254	267
Total	**295,577**	**328,546**	**346,090**	**412,724**

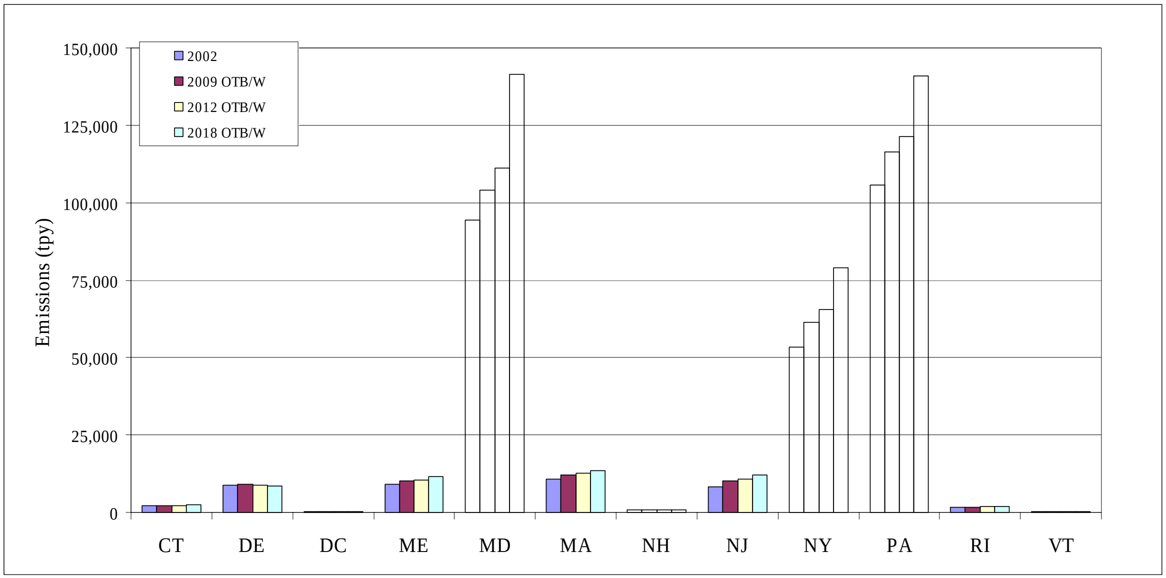


Table 2-3 NonEGU Point Sources
OTB/OTW Annual NH3 Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	0	0	0	0
DE	153	145	138	134
DC	4	5	5	5
ME	700	796	809	859
MD	305	347	366	410
MA	462	510	521	563
NH	37	46	50	60
NJ	0	0	0	0
NY	1,027	1,081	1,128	1,296
PA	1,170	1,307	1,363	1,591
RI	58	64	68	68
VT	0	0	0	0
Total	**3,916**	**4,301**	**4,448**	**4,986**

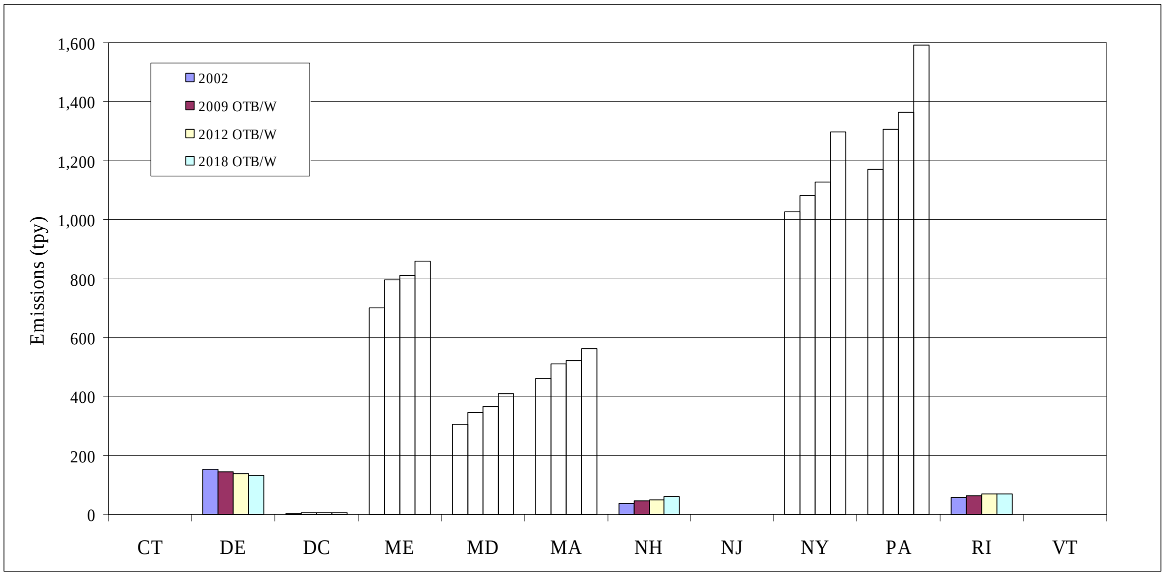


Table 2-4 NonEGU Point Sources
OTB/OTW Annual NOx Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	6,773	7,236	7,465	7,921
DE	4,372	4,076	4,135	4,246
DC	480	548	577	627
ME	12,108	14,285	14,661	15,753
MD	21,940	19,401	20,399	22,797
MA	18,292	20,603	21,372	23,040
NH	1,188	1,384	1,394	1,435
NJ	15,812	16,498	17,091	18,805
NY	34,253	33,648	34,586	37,133
PA	89,136	89,932	93,526	103,137
RI	2,308	2,449	2,471	2,442
VT	386	462	460	466
Total	**207,048**	**210,522**	**218,137**	**237,802**

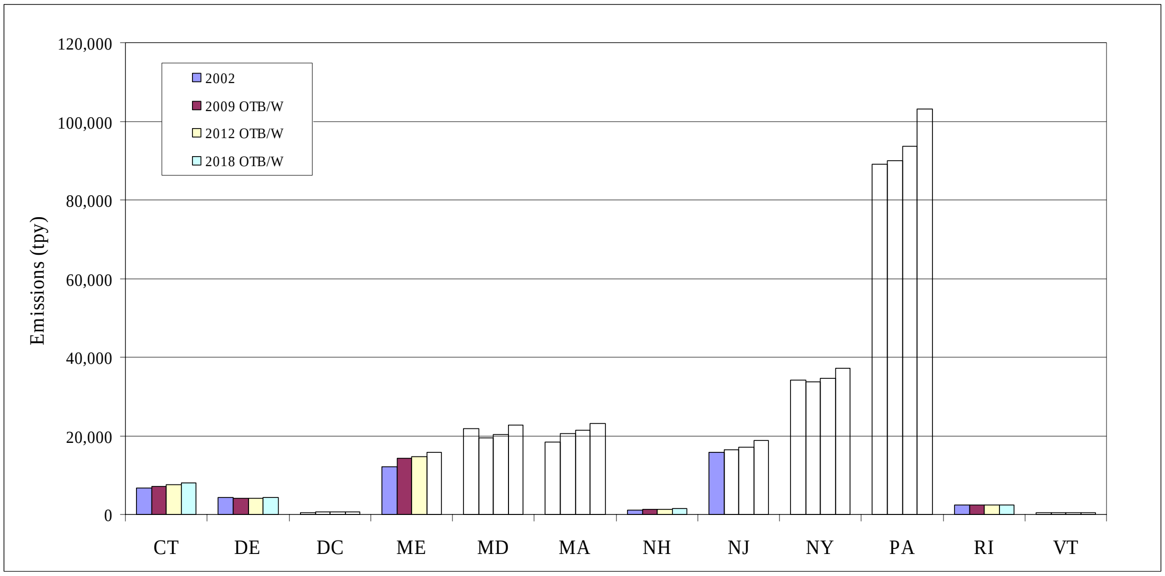


Table 2-5 NonEGU Point Sources
OTB/OTW Annual PM10-PRI Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	990	1,035	1,058	1,106
DE	1,820	1,486	1,475	1,487
DC	157	178	186	198
ME	6,120	7,088	7,133	7,496
MD	4,739	4,797	5,040	5,828
MA	4,212	5,006	5,088	5,314
NH	918	1,084	1,097	1,129
NJ	3,439	4,205	4,417	4,959
NY	5,072	5,221	5,444	6,098
PA	23,282	25,169	26,307	29,516
RI	296	333	331	330
VT	235	267	272	296
Total	**51,280**	**55,869**	**57,848**	**63,757**

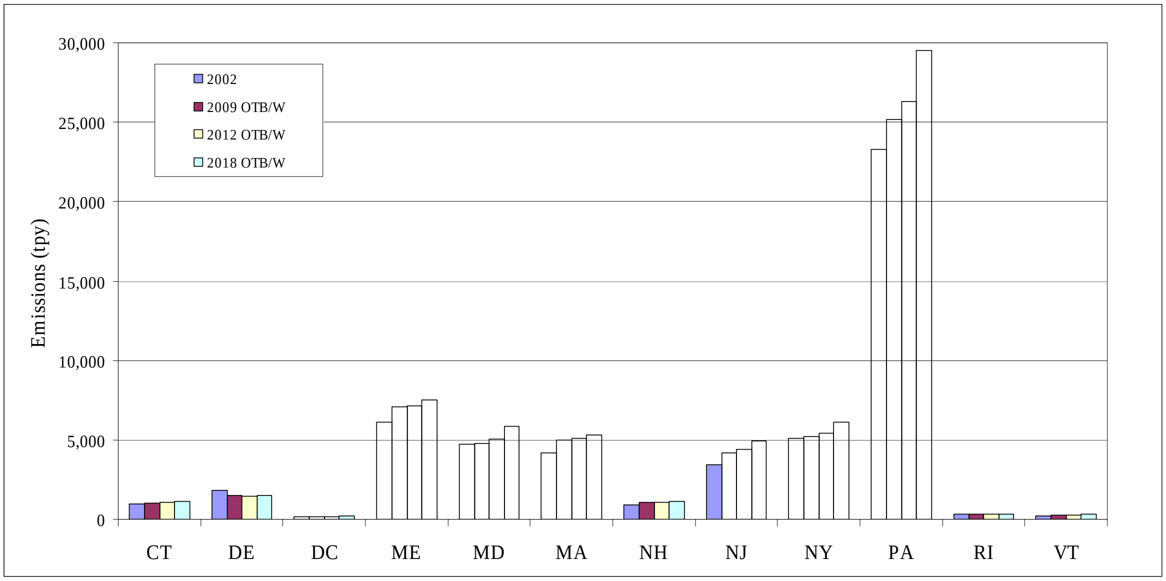


Table 2-6 NonEGU Point Sources
OTB/OTW Annual PM25-PRI Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	822	871	894	939
DE	1,606	1,256	1,245	1,254
DC	128	145	152	164
ME	4,899	5,675	5,690	5,935
MD	2,772	2,861	3,011	3,503
MA	2,953	3,554	3,574	3,660
NH	857	1,008	1,021	1,052
NJ	2,947	3,588	3,764	4,234
NY	3,355	3,535	3,688	4,161
PA	12,360	13,578	14,159	15,878
RI	180	200	198	194
VT	198	226	229	246
Total	**33,077**	**36,497**	**37,625**	**41,220**

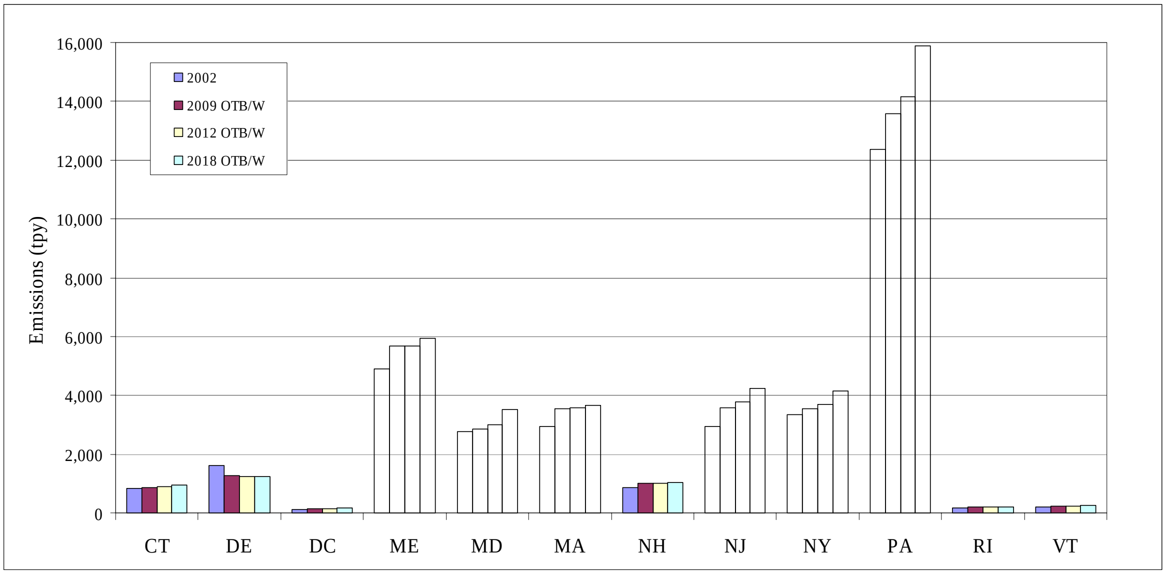


Table 2-7 NonEGU Point Sources
OTB/OTW Annual SO2 Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	2,438	2,528	2,567	2,644
DE	35,706	7,117	7,401	7,610
DC	618	707	735	780
ME	14,412	18,656	18,492	18,794
MD	34,193	34,223	35,373	38,921
MA	14,766	18,185	18,442	18,955
NH	2,436	3,099	3,098	3,114
NJ	9,797	7,141	7,234	7,856
NY	58,227	62,922	64,484	67,545
PA	88,259	90,735	93,441	99,924
RI	2,651	3,163	3,182	3,164
VT	874	1,182	1,147	1,127
Total	**264,377**	**249,658**	**255,596**	**270,434**

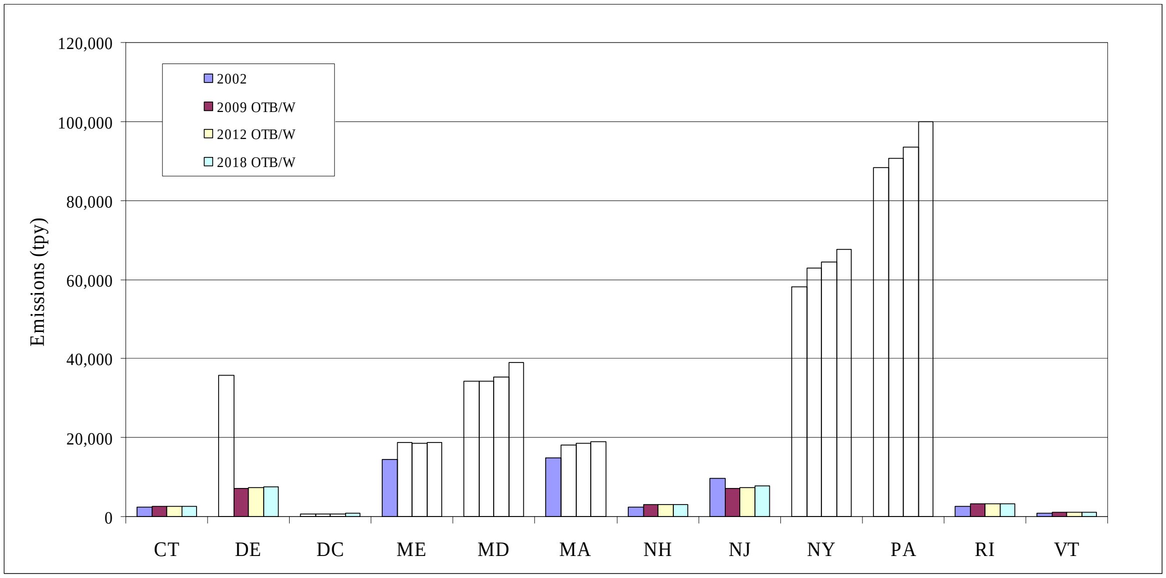
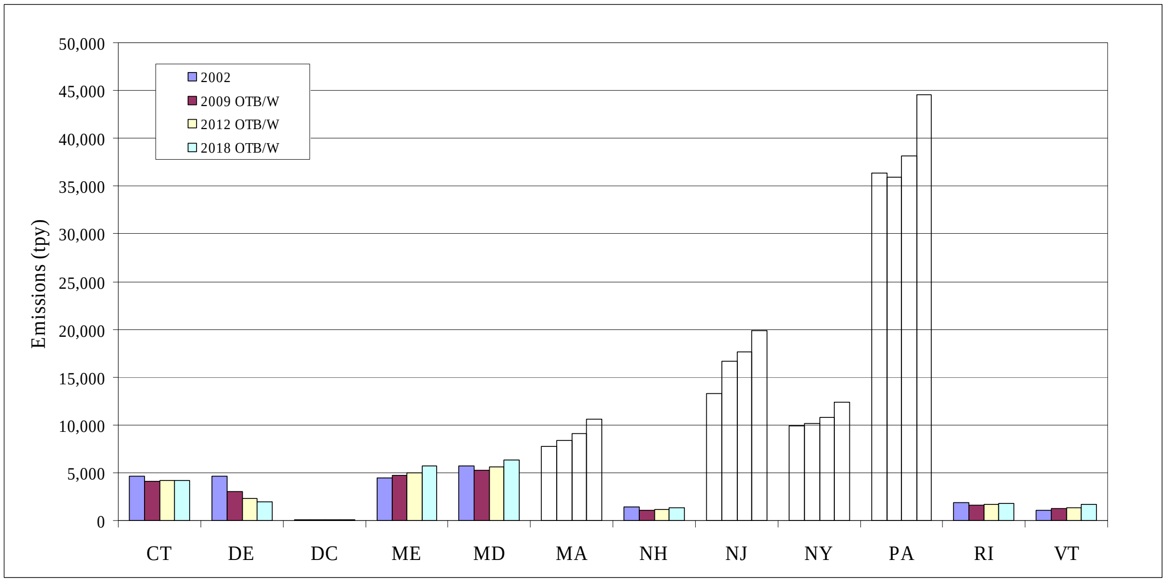


Table 2-8 NonEGU Point Sources
OTB/OTW Annual VOC Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	4,604	4,114	4,152	4,230
DE	4,645	2,987	2,311	1,993
DC	69	72	75	85
ME	4,477	4,740	4,985	5,709
MD	5,676	5,297	5,578	6,301
MA	7,794	8,381	9,061	10,564
NH	1,459	1,060	1,132	1,294
NJ	13,318	16,702	17,621	19,915
NY	9,933	10,157	10,750	12,354
PA	36,326	35,875	38,162	44,537
RI	1,898	1,640	1,695	1,812
VT	1,079	1,254	1,365	1,730
Total	**91,278**	**92,279**	**96,887**	**110,524**



3.0 AREA SOURCES

The area source sector is comprised of stationary sources that are small and numerous, and that have not been inventoried individually as specific point, mobile, or biogenic sources. Individual sources are typically grouped with other like sources into area source categories and the emissions are calculated on a county-by-county basis. Area source categories include residential/commercial/industrial fuel combustion; small industrial processes; solvent utilization (such as architectural coatings and consumer products); petroleum product storage and transport (such as gasoline service stations); waste disposal; and agricultural activities.

The procedures for projecting emissions for area sources are described in this section. We started with the MANE-VU 2002 area source emission inventory. We first applied growth factors to account for changes in population and economic activity. Next, we applied control factors to account for future emission reductions from on-the-books (OTB) control regulations and on-the-way (OTW) control regulations. The OTB control scenario accounts for post-2002 emission reductions from promulgated federal, State, local, and site-specific control programs as of June 15, 2005. The OTW control scenario accounts for proposed (but not final) control programs that are reasonably anticipated to result in post-2002 emission reductions. We then conducted a series of quality assurance steps to ensure the development of complete, accurate, and consistent emission inventories. We provided the inventories in three formats – the National Emission Inventory Input Format (NIF), SMOKE Inventory Data Analyzer (IDA) format, and SMOKE growth/control packets. We also prepared emission summary tables by state and pollutant. Each of these activities is discussed in this section.

3.1 INITIAL 2002 AREA SOURCE EMISSION INVENTORY

The starting point for the area source projections was Version 3 of the MANE-VU 2002 area source emission inventory (MANE-VU_2002_Area_040606.MDB). There were two updates to this version of the 2002 inventory in response to requests from the District of Columbia and Massachusetts. These changes, described in the following paragraphs, were used in preparing the 2009/2012/2018 projections.

After release of Version 3 of the MANE-VU 2002 inventory, the District of Columbia discovered a gross error in the 2002 residential, non-residential and roadway construction. They requested that the following values be used for the 2002 base year and as the basis for the 2009/2012/2018 projections:

SCC	Pollutant Code	2002 Annual Emissions (tpy)
2311010000	PM10-PRI	8.2933
	PM25-PRI	1.6587
2311020000	PM10-PRI	486.1951
	PM25-PRI	97.239
2311030000	PM10-PRI	289.8579
	PM25-PRI	57.9716

After release of Version 3 of the MANE-VU 2002 inventory, Massachusetts revised their inventory of area source heating oil emissions due to two changes: (1) SO2 emission factors were adjusted for the sulfur content from 1.0 to 0.03; and (2) use of the latest DOE-EIA 2002 fuel use data instead of the previous version used 2001. These two changes significantly altered the 2002 SO2 emissions for area source heating oil combustion. Massachusetts provided revised 2002 PE and EM tables, which MACTEC used in preparing the 2009/2012/2018 projection inventories.

3.2 AREA SOURCE GROWTH FACTORS

The area source growth factors were developed using three sets of data:

- The U.S. EPA's Economic Growth and Analysis System Version 5.0 (EGAS 5.0) using the default SCC configuration. EGAS 5.0 generates growth factors from REMI's 53 Sector Policy Insight Model Version 5.5, the U.S. Department of Energy (DOE) Annual Energy Outlook 2004 (AEO2004) fuel use projections, and national vehicle mile travel projections from EPA's MOBILE 4.1 Fuel Combustion Model;
- The DOE's Annual Energy Outlook 2005 (AEO2005) fuel consumption forecasts were used to replace the AEO2004 forecasts that are used as the default values in EGAS 5.0; and
- State-supplied population, employment, and other emission projection data.

The priority for applying these growth factors was to first use the state-supplied projection data (if available). If no state-supplied data are available, then we used the AEO2005 projection factors for fuel consumption sources. If data from these two sources were not available, we used the EGAS 5.0 default SCC configuration. Appendix C lists the area source growth factors used for this study.

3.2.1 EGAS 5.0 Growth Factors

EGAS is an EPA-developed economic and activity forecast tool that provides credible growth factors for developing emission inventory projections. Growth factors are generated using national- and regional-economic forecasts. For nonEGUs, the primary economic activity data sets in EGAS 5.0 are:

- State-specific growth rates from the Regional Economic Model, Inc. (REMI) Policy Insight® model, version 5.5. The REMI socioeconomic data (output by industry sector, population, farm sector value added, and gasoline and oil expenditures) are available by 4-digit SIC code at the State level.
- Energy consumption data from the DOE's Energy Information Administration's (EIA) *Annual Energy Outlook 2004, with Projections through 2025* for use in generating growth factors for non-EGU fuel combustion sources. These data include regional or national fuel-use forecast data that were mapped to specific SCCs for the non-EGU fuel use sectors (e.g., commercial coal, industrial natural gas). Growth factors are reported at the Census division level. These Census divisions represent a group of States (e.g., the South Atlantic division includes Delaware, the District of Columbia, and Maryland; the Middle Atlantic division includes New Jersey, New York, and Pennsylvania; the New England division includes Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont). Although one might expect different growth rates in each of these States due to unique demographic and socioeconomic trends, all States within each division received the same growth rate.

EGAS uses these economic activity datasets and a set of cross-reference files to generate growth factors by Standard Industrial Classification (SIC) code, Source Classification Code (SCC), or Maximum Achievable Control Technology (MACT) codes. Growth factors for 2009, 2012, and 2018 were calculated using 2002 as the base year at the State and SCC level. County-specific growth factors are not available in EGAS 5.0.

There were several SCCs in the MANE-VU 2002 inventory that are not included in the EGAS 5.0 files. As a result, EGAS did not generate growth factors for those SCCs. MACTEC assigned growth factors for the missing SCCs by assigning a surrogate SCC that best represented the missing SCC.

3.2.2 AEO2005 Growth Factors

The default version of EGAS 5.0 uses the DOE's AEO2004 forecasts. We replaced these data with the more recent AEO2005 forecasts to improve the emissions growth factors produced. Using ACCESS, we created a copy of the "DOE EGAS 5" dataset. The dataset includes three tables. One table contains the projection data values from 2001-2025. The other two tables are the MACT and SCC crosswalk tables. The crosswalk tables are linked to the projection table via a "model code". Using the copy of AEO2004 data, we updated the corresponding projection tables with data from the AEO2005 located at: http://www.eia.doe.gov/oiaf/aeo/supplement/supref.html . Using the data and descriptions from the new tables, we matched the projection data to the appropriate model codes and then built a table identical to the DOE EGAS 5 dataset with the new 2005 AEO data. The resulting ACCESS dataset contains a projection data table with the exact same structure as the original except with the new data. The SCC and MACT crosswalks did not require any updates since the model code assignments were not changed in the new data table.

3.2.3 State Specific Growth Factors

In addition to the growth data described above, we received growth projections from several MANE-VU states to be used instead of the default EGAS or AEO2005 growth factors. The following paragraphs describe the area source growth factors used for each state.

3.2.3.1 Connecticut

Connecticut provided state-level population projections for 2009, 2012, and 2018. We created growth factors for those SCCs that are population based using the state-supplied data. Connecticut also provided state-level employment projections for industry categories analogous to 2-digit SIC codes. Projections were provided for 2009, 2012, and 2018. We matched these industry groupings to SCC codes in order to create SCC specific growth factors for area sources. Emissions from area source fuel combustion were projected using the AEO2005 forecasts.

3.2.3.2 Delaware

Delaware provided county-level population projections (*Delaware Population Consortium Annual Population Projections*, Oct 18, 2001 Version 2001.0) for 2000, 2005, 2010, 2015, and 2020. We interpolated these data to get growth factors for projection from 2002 to 2009, 2012, and 2018 for those SCCs that are population based. Delaware also provided state-level employment data by NAICS codes for 2002 and 2012. We interpolated values for 2009 and 2018. We matched these industry groupings to SCC codes in order to create SCC specific growth factors for selected area sources. Emissions from area source fuel combustion were projected using the AEO2005 forecasts.

3.2.3.3 District of Columbia

DC provided local growth factors for projecting emissions from 2002 to 2009, 2012, and 2018 for all area source SCCs except fuel combustion sources. Emissions from area source fuel combustion were projected using the AEO2005 forecasts.

3.2.3.4 Maine

Maine indicated that it preferred to use the EGAS 5.0 growth factors and the DOE's 2005 Annual Energy Outlook data for combustion sources.

3.2.3.5 Maryland

Maryland provided growth factors by SCC for all counties in the State. These growth factors were derived from a variety source sources, including the MWCOG Cooperative Forecast 7.0, the BMC Round 6A Cooperative Forecast (prepared by the MD Dept. of Planning, May 2004), and EGAS 5.0.

3.2.3.6 Massachusetts

Massachusetts provided county-level population data for the years 2000, 2010, and 2020. We interpolated these data to get growth factors for projection from 2002 to 2009, 2012, and 2018 for those SCCs that are population based. Massachusetts also provided growth factors for several SCCs based on employment data for the years 2000 and 2010. We interpolated these data to get growth factors for projection from 2002 to 2009, 2012, and 2018. Massachusetts agreed on the use of the AEO2005 forecasts for projecting emissions from area source fuel combustion.

3.2.3.7 New Hampshire

New Hampshire agreed to use the EGAS 5.0 growth factors, with the enhancement of using the DOE's 2005 Annual Energy Outlook data for combustion sources.

3.2.3.8 New Jersey

New Jersey provided growth factors for most SCCs for all counties in the State. When state-specific growth factors were not available, we used the AEO2005 forecasts for projecting emissions from area source fuel combustion and EGAS default factors for any remaining categories.

3.2.3.9 New York

New York provided county-level population data for 2002 and projections/growth factors for 2009, 2012, and 2018. We used these growth factors for those SCCs that are population based. We used the AEO2005 forecasts for projecting emissions from area source fuel combustion and EGAS default factors for any remaining categories.

3.2.3.10 Pennsylvania

Pennsylvania provided county-level population data for 2000 and projections for 2010 and 2020. We interpolated these data to get growth factors for projecting from 2002 to 2009, 2012, and 2018 for those SCCs that are population based. Pennsylvania also provided general employment data for 21 counties or area for 2000 and projections for 2010 and 2020. We interpolated these data to get growth factors for projecting from 2002 to 2009, 2012, and 2018 for nine area source categories identified by Pennsylvania. For all other area source categories, we used the AEO2005 forecasts for projecting emissions from area source fuel combustion and EGAS default factors for any remaining categories.

3.2.3.11 Rhode Island

Rhode Island provided county-level population projections for 2000, 2005, 2010, 2015, and 2020. We interpolated these data to get growth factors for projection from 2002 to 2009, 2012, and 2018 for those SCCs that are population based. Rhode Island provided state-level employment data from the Department of Labor and Training by 3-digit NAICS codes for 2002 and 2012. We used these data to calculate the growth factor from 2002 to 2012 and interpolated these data to derive growth factors for 2009 and 2018. We matched these industry NAICS groupings to SCC codes in order to create SCC specific growth factors for area sources. Rhode Island agreed on the use of the AEO2005 forecasts for projecting emissions from area source fuel combustion.

3.2.3.12 Vermont

Vermont agreed to use the EGAS 5.0 growth factors, with the enhancement of using the DOE’s 2005 Annual Energy Outlook data for combustion sources.

3.3 AREA SOURCE CONTROL FACTORS

We developed control factors to estimate emission reductions that will result from on-the-books regulations that will result in post-2002 emission reductions and proposed regulations or actions that will result in post-2002 reductions. Control factors were developed for the following national or regional control measures:

- OTC VOC Model Rules
- Federal On-board Vapor Recovery
- New Jersey Post-2002 Area Source Controls
- Residential Woodstove NSPS

3.3.1 OTC 2001 VOC Model Rules

Most of the MANE-VU States have adopted (or will soon adopt) the Ozone Transport Commission (OTC) model rules for five area source VOC categories: consumer products, architectural and industrial maintenance (AIM) coatings, portable fuel containers, mobile equipment repair and refinishing (MERR), and solvent cleaning. Information on the percent reduction anticipated by each model rule was obtained from Table II-6 of *Control Measure Development Support Analysis of Ozone Transport Commission Model Rules* (E.H. Pechan & Associates, Inc., March 31, 2001). This set of model rules will be referred to as the "OTC 2001 model rules" in this document. Information as to whether a particular state has adopted (or will soon adopt) a particular measure was obtained form the Status Report on OTC States' Efforts to Promulgate Regulations Based on OTC Model Rules (As of June 1, 2005, as posted on the OTC web site). For all categories, except portable fuel containers (see discussion below), we assumed that the rules would be fully implemented by <u>all states by 2009</u>. Some states had already adopted some the OTC 2001 Model Rules in 2002 or already had similar rules in place in 2002. The 2002 emission inventory for those states already reflected the emission reductions expected from the OTC 2001 Model Rule level of control. For those states and categories, no incremental reductions were applied for to the future year projections, as indicated Table 3-1.

For consumer products, the 2001 OTC model rule was estimated to provide a 14.2 percent VOC emissions reductions from the Federal Part 59 rule. Most, but not all, states in the OTR have adopted the OTC 2001 model rule for consumer products. For this inventory, it was assumed that all OTC states would adopt the 2001 OTC model rule prior to 2009. Thus, the 14.2 percent control factor was applied uniformly to all states in the 2009, 2012, and 2018 projection inventories.

For AIM coatings, the 2001 OTC model rule was estimated to provide a 31 percent VOC emissions reduction from the Federal Part 59 rule. Most, but not all, states in the OTR have adopted the OTC 2001 model rule for AIM coatings. For this inventory, it was assumed that all OTC states would adopt the 2001 OTC model rule prior to 2009. Thus, this control factor was applied uniformly to all states, with one exception. Maine adopted the OTC model rule with an alternative VOC content limit for varnishes and interior wood clear and semitransparent wood stains. As a result, Maine estimated that reductions from AIM coatings should be modeled using a 29.5 percent control factor instead of the 31 percent estimated for the OTC 2001 model rule.

For portable fuel containers, the 2001 OTC model rule was estimated to provide a 75 percent reduction in VOC emissions at the end of an assumed 10-year phase-in period as

Table 3-1 Adoption Matrix for 2001 OTC Model Rules

State	Consumer Products	AIM Coatings	Portable Fuel Containers	Mobile Equipment Repair and Refinishing	Solvent Cleaning
CT	Yes	Yes	Yes	Yes	Yes
DE	Yes	Yes	Yes	Yes	No
DC	Yes	Yes	Yes	Yes	No
ME	Yes	Yes	Yes	Yes	Yes
MD	Yes	Yes	Yes	No	No
MA	Yes	Yes	Yes	No	* (7%)
NH	Yes	Yes	Yes	Yes	Yes
NJ	Yes	Yes	Yes	Yes	** (17%)
NY	Yes	Yes	Yes	Yes	Yes
PA	Yes	Yes	Yes	No	No
RI	Yes	Yes	Yes	Yes	Yes
VT	Yes	Yes	Yes	Yes	No

Yes – apply incremental reductions in future years
No – OTC Model Rule reductions already accounted for in 2002 inventory; no incremental reductions applied to future years.
* MA is amending its existing Solvent/Degreasing rule and anticipates a 7% reduction from 2002 levels.
** NJ amended its existing Solvent/Degreasing rule and anticipates a 17% reduction from 2002 levels

older non-compliant containers are replaced with new compliant containers. The rule penetration (RP) depends on the assumed PFC estimated useful life and how quickly old non-compliant containers are replaced with new compliant containers. For the 2001 OTC model rule, the turnover from old to new containers is expected to be 10 percent per year. The MANEVU states have adopted the OTC 2001 model rule at different times, so the rule penetration will vary by State depending upon when the rule became effective in a given state. For example, compliant containers were required in Pennsylvania beginning on January 1, 2003. By the 2009 ozone season, there will be a 6.5 year turnover period for compliant PFCs in Pennsylvania. By contrast, compliant containers in New Jersey were not required until January 1, 2005. Thus, by the 2009 ozone season, there will be a 4.5 year turnover period for compliant PFCs. Table 3.2 shows the effective date for compliant containers by state, along with the rule penetration factors and overall control efficiency. There are different rule penetration factors for the three inventory years because of the increased penetration of compliant containers into the marketplace. By 2018, 100 percent compliance is assumed.

Table 3-2 Rule Penetration and Control Efficiency Values for 2001 OTC Model Rule for PFCs

Rule Compliance Date	States with this Compliance Date	Control Efficiency (%)	Rule Penetration (%)	Overall Control Efficiency (%)
Control Factor for 2009 Inventory				
2003	MD, NY, PA	75	65	48.8
2004	CT, DE, DC, ME	75	55	41.3
2005	NJ	75	45	33.8
2006	NH	75	35	26.3
2007*	MA, RI, VT	75	25	18.8
Control Factor for 2012 Inventory				
2003	MD, NY, PA	75	95	71.3
2004	CT, DE, DC, ME	75	85	63.8
2005	NJ	75	75	56.3
2006	NH	75	65	48.8
2007*	MA, RI, VT	75	55	41.3
Control Factor for 2018 Inventory				
2003	MD, NY, PA	75	100	75.0
2004	CT, DE, DC, ME	75	100	75.0
2005	NJ	75	100	75.0
2006	NH	75	100	75.0
2007*	MA, RI, VT	75	100	75.0

* The 2001 OTC model rule is not yet effective. It was assumed to become effective January 1, 2007 for the MANEVU modeling inventory. Massachusetts' rule actually will not become effective until 2009 and is based only on the OTC 2006 model rule; Massachusetts will not adopt the OTC 2001 model rule.

The emission reductions from the 2001 OTC PFC model rule were calculated only for the emissions accounted for in the area source inventory. Additional benefits (not estimated for this report) would be expected from equipment refueling vapor displacement and spillage that is accounted for in the nonroad inventory.

For mobile equipment repair and refinishing, the 2001 OTC model rule was estimated to provide a 38 percent VOC emissions reductions from the Federal Part 59 rule (35% for paint application and 3% for cleaning operations). Most, but not all, states in the OTR have adopted the OTC 2001 model rule for MERR or already had similar rules in effect in

2002. For this inventory, it was assumed that all OTC states would adopt the 2001 OTC model rule prior to 2009 or have similar rules in effect. For those states (MD, MA, PA) that had similar rules in effect in 2002 or earlier, no incremental reductions were applied since it was assumed that the effects of the state rule were already accounted for in the 2002 inventory. New Jersey indicated that a 19 percent control factor should be used for VOC emissions from MERR in New Jersey. For all other states, the OTC 2001 Model Rule control factor of 38 percent was applied.

For solvent cleaning, the 2001 OTC model rule was estimated to provide a 66 percent VOC emissions reductions. Most, but not all, states in the OTR have adopted the OTC 2001 model rule for solvent cleaning or already had similar rules in effect in 2002. For this inventory, it was assumed that all OTC states would adopt the 2001 OTC model rule prior to 2009 or have similar rules in effect. For those states (DE, DC, MD, PA, VT) that had similar rules in effect in 2002 or earlier, no incremental reductions were applied since it was assumed that the effects of the state rule were already accounted for in the 2002 inventory. Massachusetts indicated that some portion of the reductions resulting from the OTC 2001 model rule were already accounted for in their 2002 emissions, but that the state anticipated an additional 7 percent reduction from anticipated amendments. New Jersey indicated that a 17 percent control factor should be used for VOC emissions from solvent cleaning in New Jersey. For all other states (CT, ME, NH, NY, RI), the OTC 2001 Model Rule control factor of 66 percent was applied.

Table D-1 in Appendix D shows the anticipated percent reductions by state, SCC, and year from implementation of the OTC 2001 VOC Model Rules.

3.3.2 On-Board Vapor Recovery

The U.S. EPA issued regulations requiring onboard vapor recovery (ORVR) standards for the control of vehicle refueling emissions in 1994. ORVR works by routing refueling vapors to a carbon canister on the vehicle and are expected to achieve from 95-98 percent reduction in VOC emissions for those vehicles equipped with ORVR. ORVR is required to be installed on some new light-duty gasoline vehicles in 1998, and all new light-and medium-duty automobiles and trucks will be required to have ORVR installed by 2006.

For the Lake Michigan Air Directors Consortium, E.H. Pechan made estimates of emission reductions as they grow over time due to increased rule penetration. The following discussion describes how the on-board vapor recovery control factors were developed (email from Maureen Mullen, E.H. Pechan):

> "Onroad refueling control factors were calculated based on the percentage difference between the projection year (2007, 2008, 2009, 2012, and 2018) MOBILE6 refueling emission factors and the 2002 MOBILE6 refueling emission factors.
>
> MOBILE6 emission factors were calculated at January and July temperature and fuel conditions. July emission factors were used as the surrogate for the five-month ozone season (May through September) and the January emission factors were used as the surrogates for the remaining seven months. Temperatures modeled were the January and July average daily monthly maximum and minimum temperatures for each State, based on 30-year average temperature data, as used in EPA's second Section 812 Prospective analysis. Within a State, MOBILE6 input files were created for each unique combination of: January and July RVP, RFG, oxygenated fuel, and Stage II control programs. Fuel data was based on 2002 data, also as used in the Section 812 analysis. Information on Stage II control programs and control efficiencies were provided by EPA, as included in the draft 2002 NEI. Using these same temperature inputs, fuel inputs, and Stage II control inputs (where applicable), Pechan calculated MOBILE6 emission factors for calendar years 2002, 2007, 2008, 2009, 2012, and 2018.
>
> The resulting MOBILE6 emission factors were first weighted according to the default MOBILE6 VMT mix to determine the weighted average refueling emission factor for all gasoline vehicle types. The resulting January and July emission factors were weighted together according to the number of days in the seven-month season (212 days) and the five-month ozone season (153). After this was done for all of the modeled years and State or sub-State areas, the overall control efficiency for refueling, due to fleet turnover, was calculated based on the percentage difference between the 2002 and corresponding projection year emission factors. These control efficiencies were then assigned to individual counties, based on the mapping of fuel and Stage II control parameters to those modeled in the MOBILE6 files."

These projections were made on a county-by-county basis. Table D-2 shows the anticipated percent reductions by county, SCC, and year.

3.3.3 Post-2002 Area Source Controls in New Jersey

New Jersey made gasoline transfer provision amendments at N.J.A.C. 7:27-16.3. The Stage I portion of the amendments are expected to result in emissions reductions of 23.2 percent from the 2002 baseline. This is based on a control efficiency of 29 percent and a rule effectiveness of 80 percent. The State II portion of the amendments are already incorporated into the inventory through the MOBILE6 inputs.

New Jersey also made amendments to ICI boiler provisions at N.J.A.C. The amendments require any ICI boiler has a maximum gross heat input rate of at least 5 mmBTU/hour, whether or not it is located at a major NO_x facility, to conduct annual tune-ups. In the support documentation for this rule amendment, New Jersey estimated that the tune-ups would result in a 25 percent reduction in NOx emissions.

3.3.4 Residential Wood Combustion

Control factors were evaluated to account for the replacement of retired woodstoves that emit at pre-new source performance standard (NSPS) levels. We used EPA's latest methodology provided by Marc Houyoux of EPA/OAQPS. This methodology uses a combination growth and control factor and is based on activity not pollutant. The growth and control are accounted for in a single factor the SCCs split out the controlled and uncontrolled equipment. The control is indirectly incorporated based on which stove is used. The combined growth and control rates are as follows:

- Fireplaces increase 1%/yr
- Old woodstoves (non-EPA certified) decrease 2%/yr
- New woodstoves (EPA certified) increase 2%/yr

The data to support these rates were collected as part of the woodstove change-out program development in OAQPS. Table D-3 shows the anticipated percent changes by SCC and year.

3.4 AREA SOURCE QA/QC REVIEW

Throughout the inventory development process, quality assurance steps were performed to ensure that no double counting of emissions occurred, to ensure that a full and complete inventory was developed for MANE-VU, and to make sure that projection calculations were working correctly. Quality assurance was an important component to the inventory development process and MACTEC performed the following QA steps on the area source components of the 2009/2012/2018 projection inventories:

1. State agencies reviewed the draft growth and control factors in the summer of 2005. Changes based on these comments were implemented in the files.
2. SCC level emission summaries were prepared and evaluated to ensure that emissions were consistent and that there were no missing sources. Tier comparisons (by pollutant) were developed between the revised 2002 base year inventory and the 2009/2012/2018 projection inventories.
3. Emission inventory files in NIF format were provided for state agency review and comment. Changes based on these comments were implemented.
4. All final files were run through EPA's Format and Content checking software.

3.5 AREA SOURCE NIF, SMOKE AND SUMMARY FILES

The Version 3 file names and descriptions delivered to MARAMA are shown in Table 3-3.

3.6 AREA SOURCE EMISSION SUMMARIES

Emission summaries by state, year, and pollutant are presented in Tables 3-4 through 3-10 for CO, NH3, NOx, PM10-PRI, PM25-PRI, SO2, and VOC, respectively.

Table 3-3 Area Source NIF, IDA, and Summary File Names

File Name	Date	Description
MANEVU_OTB2009_Area_NIFV3_2.mdb	Nov. 9, 2006	Version 3.2 of 2009 OTB area source NIF inventory
MANEVU_OTB2012_Area_NIFV3_2.mdb	Nov. 9, 2006	Version 3.2 of 2012 OTB area source NIF inventory
MANEVU_OTB2018_Area_NIFV3_2.mdb	Nov. 9, 2006	Version 3.2 of 2018 OTB area source NIF inventory
MANEVU_OTB2009_Area_IDAV3_2.txt	Nov. 20, 2006	Version 3.2 of 2009 OTB area source inventory in SMOKE IDA format
MANEVU_OTB2012_Area_IDAV3_2.txt	Nov. 20, 2006	Version 3.2 of 2012 OTB area source inventory in SMOKE IDA format
MANEVU_OTB2018_Area_IDA3V_2.txt	Nov. 20, 2006	Version 3.2 of 2018 OTB area source inventory in SMOKE IDA format
MANEVU OTB BOTW Area V3_2 State Summary.xls	Nov. 8, 2006	Spreadsheet with state totals by pollutant for all area sources
MANEVU OTB BOTW Area V3_2 State SCC Summary.xls	Nov. 8, 2006	Spreadsheet with SCC totals by state and pollutant for all area sources.

Table 3-4 Area Sources
OTB/OTW Annual CO Emission Projections
(tons per year)

State	**2002**	**2009**	**2012**	**2018**
CT	70,198	65,865	63,874	59,797
DE	14,052	15,395	15,233	14,864
DC	2,300	2,417	2,460	2,512
ME	109,223	102,743	99,877	94,181
MD	141,178	143,653	144,233	144,649
MA	137,496	132,797	130,255	125,205
NH	79,647	76,504	75,319	73,038
NJ	97,657	90,432	88,048	83,119
NY	356,254	336,576	327,118	307,659
PA	266,935	266,887	264,012	257,396
RI	8,007	8,007	8,026	8,024
VT	43,849	42,683	42,172	41,283
Total	**1,326,796**	**1,283,959**	**1,260,627**	**1,211,727**

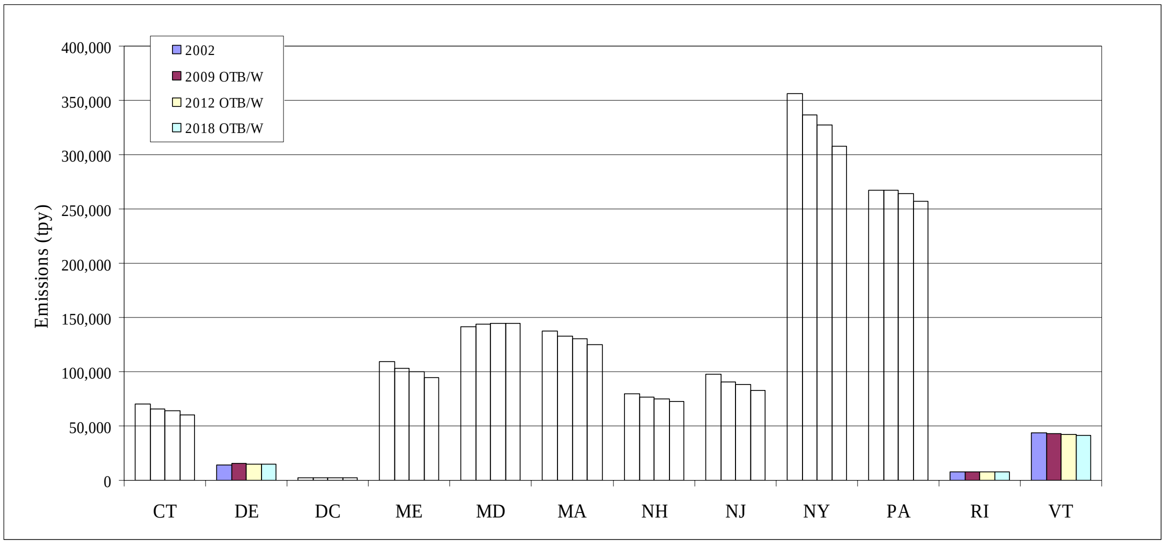


Table 3-5 Area Sources
OTB/OTW Annual NH3 Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	5,318	5,208	5,156	5,061
DE	13,279	13,316	13,328	13,342
DC	14	16	16	17
ME	8,747	10,453	11,116	12,312
MD	25,834	31,879	34,222	38,155
MA	18,809	19,131	19,275	19,552
NH	2,158	2,466	2,584	2,789
NJ	17,572	19,457	20,154	21,435
NY	67,422	81,626	87,116	96,078
PA	79,911	98,281	105,418	117,400
RI	883	945	972	1,025
VT	9,848	12,156	13,062	14,580
Total	**249,795**	**294,934**	**312,419**	**341,746**

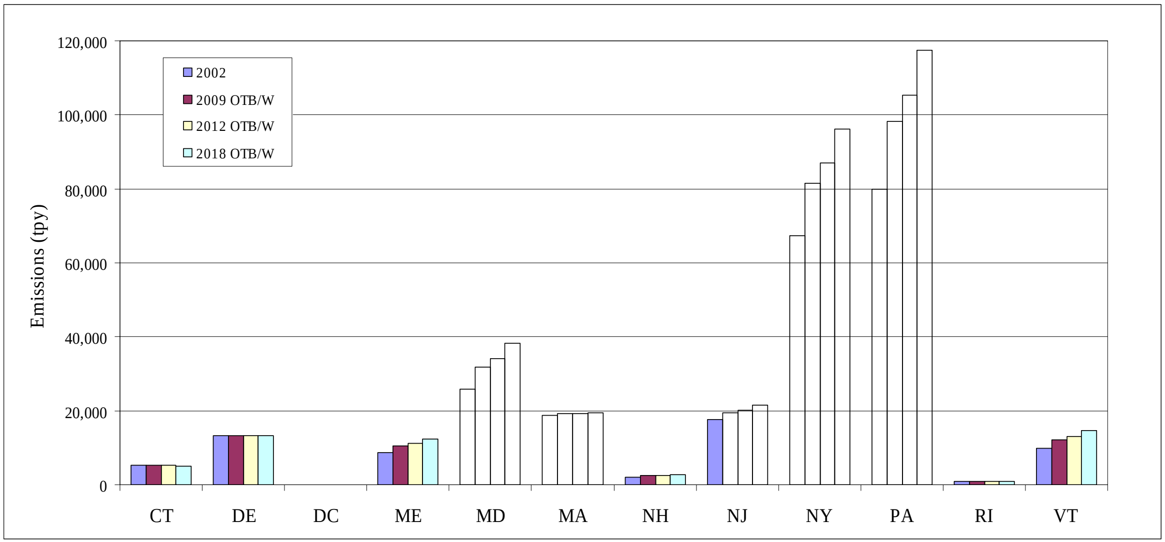


Table 3-6 Area Sources
OTB/OTW Annual NOx Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	12,689	13,173	13,342	13,388
DE	2,608	2,821	2,913	3,014
DC	1,644	1,961	2,081	2,259
ME	7,360	7,477	7,486	7,424
MD	15,678	16,858	17,315	18,073
MA	34,281	35,732	36,331	37,187
NH	10,960	11,879	12,055	12,430
NJ	26,692	24,032	23,981	23,660
NY	98,803	106,375	107,673	108,444
PA	47,591	50,162	50,793	50,829
RI	3,886	4,149	4,260	4,397
VT	3,208	3,419	3,429	3,430
Total	**265,400**	**278,038**	**281,659**	**284,535**

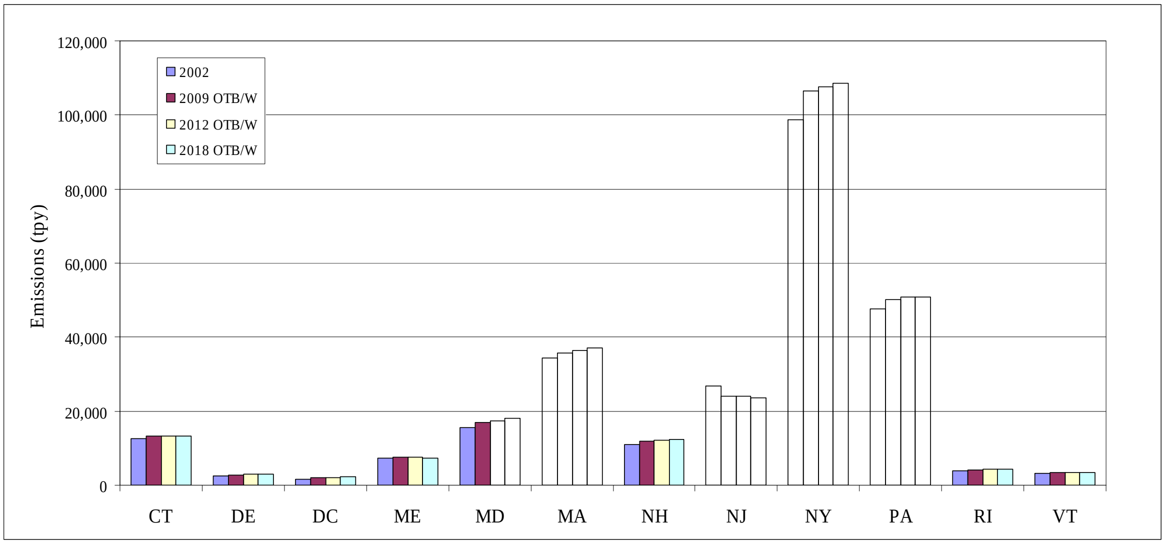


Table 3-7 Area Sources
OTB/OTW Annual PM10-PRI Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	48,281	48,970	49,004	49,479
DE	13,039	13,928	14,236	14,844
DC	3,269	3,511	3,605	3,825
ME	168,953	175,979	179,689	189,619
MD	95,060	105,944	110,141	117,396
MA	192,860	198,668	200,692	204,922
NH	43,328	46,060	47,187	49,801
NJ	61,601	61,684	61,284	60,880
NY	369,595	382,124	385,925	392,027
PA	391,897	421,235	432,844	454,970
RI	8,295	8,962	9,244	9,797
VT	56,131	60,521	62,465	66,916
Total	**1,452,309**	**1,527,586**	**1,556,316**	**1,614,476**

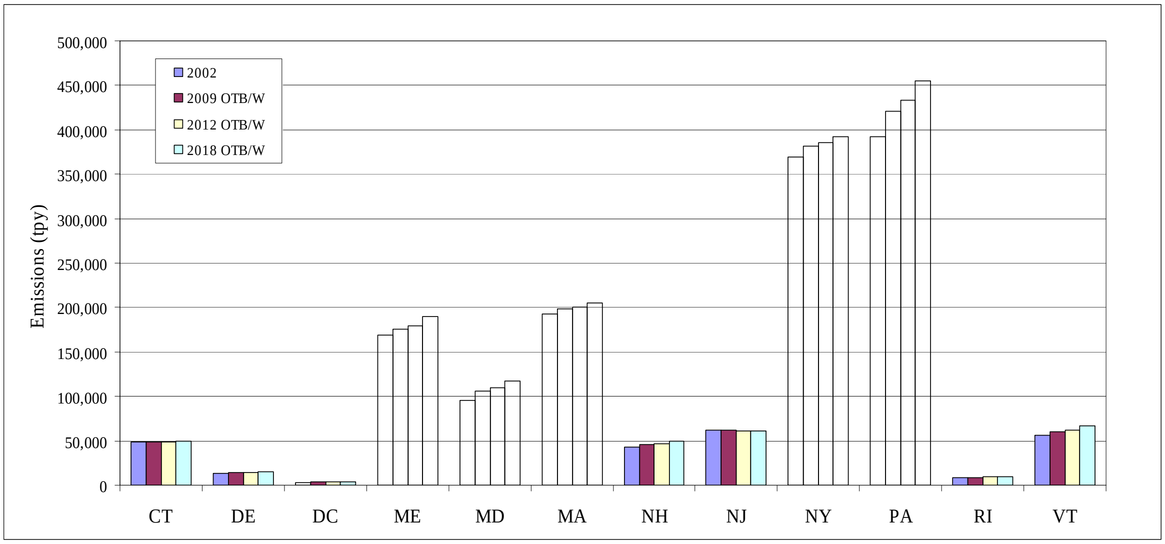


Table 3-8 Area Sources
OTB/OTW Annual PM25-PRI Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	14,247	13,766	13,517	13,033
DE	3,204	3,387	3,403	3,426
DC	805	860	879	917
ME	32,774	33,026	33,189	33,820
MD	27,318	28,923	29,508	30,449
MA	42,083	43,121	43,186	43,438
NH	17,532	17,965	18,050	18,316
NJ	19,350	18,590	18,271	17,653
NY	87,154	87,576	87,260	86,422
PA	74,925	79,169	80,728	83,570
RI	2,064	2,184	2,232	2,316
VT	11,065	11,482	11,652	12,059
Total	**332,521**	**340,049**	**341,875**	**345,419**

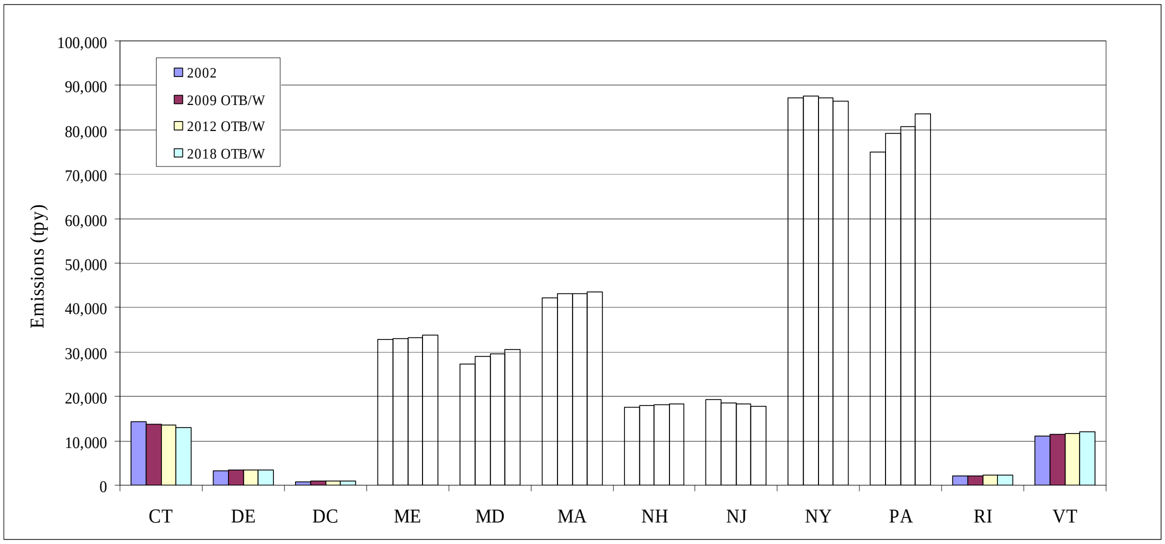


Table 3-9 Area Sources
OTB/OTW Annual SO2 Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	12,418	12,581	12,604	12,184
DE	1,588	1,599	1,602	1,545
DC	1,337	1,487	1,541	1,632
ME	13,149	13,776	13,846	13,901
MD	12,393	13,685	14,074	14,741
MA	25,488	25,961	26,029	25,570
NH	7,072	7,463	7,470	7,421
NJ	10,744	10,672	10,697	10,510
NY	130,409	139,589	140,154	141,408
PA	63,679	67,535	67,446	66,363
RI	4,557	5,024	5,189	5,398
VT	4,087	4,646	4,687	4,764
Total	**286,921**	**304,018**	**305,339**	**305,437**

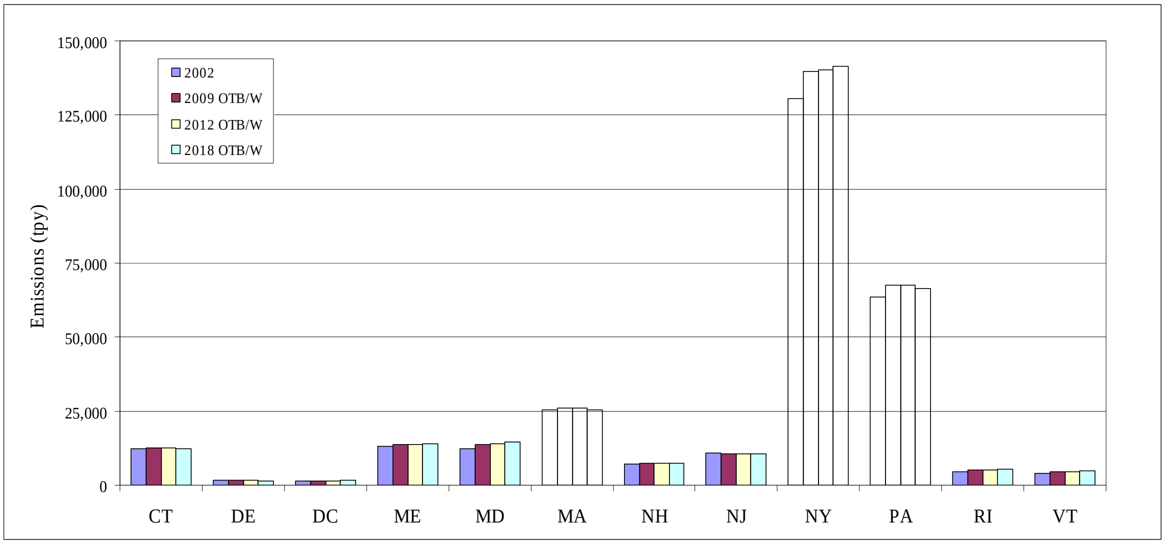
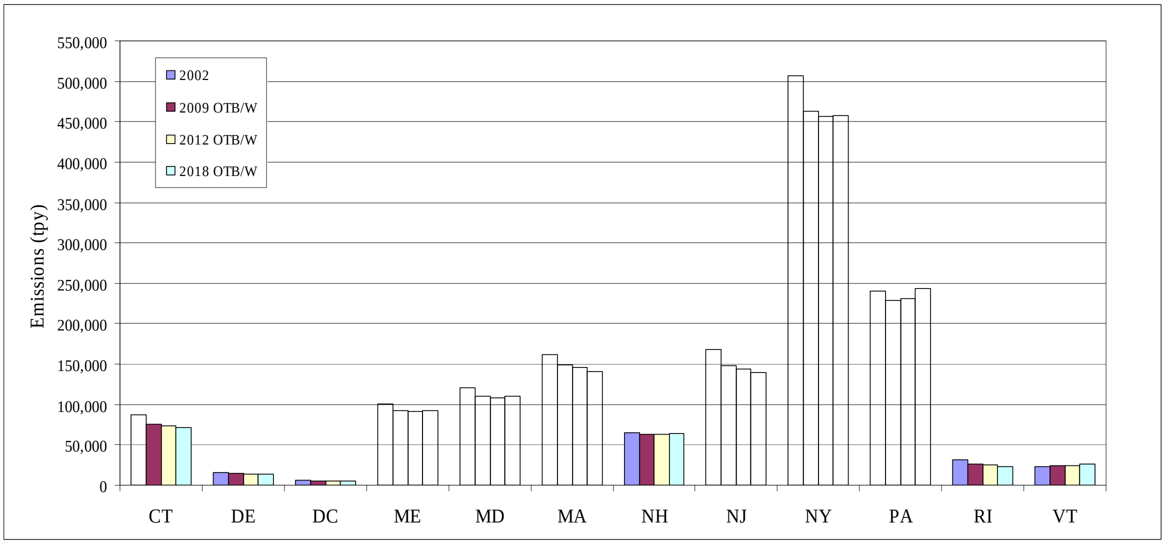


Table 3-10 Area Sources
OTB/OTW Annual VOC Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	87,302	75,693	73,560	71,274
DE	15,519	14,245	13,943	13,744
DC	6,432	5,420	5,352	5,255
ME	100,621	91,910	91,667	92,410
MD	120,254	110,385	108,067	110,046
MA	162,145	148,625	145,674	140,558
NH	65,370	63,069	63,356	64,368
NJ	167,882	147,617	143,752	139,626
NY	507,292	462,811	456,856	457,421
PA	240,785	228,444	230,393	243,421
RI	31,402	26,695	25,548	23,561
VT	23,265	24,068	24,635	26,198
Total	**1,528,269**	**1,398,982**	**1,382,803**	**1,387,882**



4.0 NONROAD SOURCES

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

4.1 NONROAD MODEL SOURCES

NONROAD model source categories include equipment such as recreational boats and watercraft; recreational vehicles; farm, industrial, mining, and construction machinery; and lawn and garden equipment. Also included are aircraft ground support equipment and rail maintenance equipment. These equipment types are powered by engines using diesel, gasoline, compressed natural gas (CNG), and liquefied petroleum gas (LPG).

EPA released a revised version of NONROAD during December 2005 called NONROAD 2005. EPA's National Mobile Inventory Model (NMIM) is a consolidated modeling system that incorporates the NONROAD and MOBILE models, along with a county database of inputs. EPA also released an updated version of NMIM called NMIM2005, which incorporates the NONROAD2005 model.

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

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

The NMIM/NONROAD2005 results in NIF 3.0, and ran EPA's QA checker program to verify that the NIF 3.0 files were properly constructed.

4.2 AIRCRAFT, COMMERCIAL MARINE, AND LOCOMOTIVES

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

MACTEC's approach to developing emission projections for these sources was to use combined growth and control factors developed from emission projections for U.S. EPA's Clean Air Interstate Rule (CAIR) development effort. MACTEC obtained emission projections developed for the CAIR rule. We then calculated the combined growth and control factors by determining the ratio of emissions between 2002 and each of the MANE-VU projection years (2009, 2012, and 2018). The CAIR emissions were available for 2001, 2010, 2015 and 2020. Thus, we developed intermediate year estimates using linear interpolation between the actual CAIR years and the MANE-VU years.

Using this approach we developed State/county/SCC/pollutant growth/control factors for use in projecting the MANE-VU base year data to the year of interest. These values were then used to multiply times the base year value to obtain the projected values. Since the development of the CAIR factors included both growth and controls, no separate control factors were developed for these sources except where exceptions to this method were used for States that requested alternative growth/control methods (see below).

Once the CAIR factors were developed, MACTEC compared the SCCs contained in the CAIR inventory with those used in MANE-VU. In some cases there were differences. In cases where a similar SCC in the CAIR inventory could be assigned to the SCC in the MANE-VU inventory the State/County/SCC/pollutant growth and control factor for the substitute was assigned to the MANE-VU SCC. If no corresponding county SCC substitution could be found, a State or MANE-VU regional average value for the substitute SCC was developed and assigned for use in projecting emissions. The substitution scheme was to use State values first, then MANE-VU regional values if the State value couldn't be used.

This projection method was used with three exceptions. These exceptions were: 1) Maryland sources, 2) DC locomotive growth and controls and 3) Logan (Boston) airport. Each of these sources used alternative growth and/or controls provided by the States or developed from current Federal rules for these sources (applies to controls only). Each of these is discussed below.

4.2.1 Maryland Non-NONROAD Source Emissions

Maryland indicated that they would prefer to use EGAS growth factors coupled with Federal controls to determine projected emissions for these source categories. Maryland provided EGAS growth factors for use with these categories. Control values were developed based on Federal rules that were on the books.

For CMV, controls were developed based on data contained in Table 1.1-2 of the document “Final Regulatory Support Document: Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder,” EPA420-R-03-004, January 2003. Values in that table were interpolated to develop emission estimates with and without controls for the MANE-VU years (and base year) and then control factors were calculated for those values. Only Category 3 marine engines were identified in the Maryland inventory and thus only NOx controls for those engines were developed.

For locomotives, control factors for different types of locomotives were developed using Tables 6-2 through 6-5 of the document “Locomotive Emission Standards: Regulatory Support Document,” United States Environmental Protection Agency, Office of Mobile Sources, April 1998. Since these tables only showed PM controls, we assumed the same level of control for both PM-10 and PM-2.5. Controls for VOC, NOx and PM were developed using these tables.

In addition to engine specification controls for both CMV and locomotives, we also developed control factors resulting from changes to diesel fuel sulfur contents. The diesel fuel sulfur regulations were utilized to develop controls for SO2 and PM due solely to changing fuel sulfur requirements. Data from Tables 3.1-6a and 3.4-8a of the document “Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines,” EPA420-R-04-007, May 2004 were used to develop control levels created due to changes in fuel sulfur content. In cases where there were controls due to both engine technology and fuel sulfur reduction, we added the control efficiencies together to create a combined control efficiency. All control values are considered to be “additive”. In other words, the controls applied are above those found in the base year. Thus the controls were used on the base year emission values without back-calculation to determine uncontrolled levels since the controls are in addition to those controls.

The control values were then applied along with the growth factors to the base year emissions for Maryland to produce the required emission projections.

4.2.2 DC Locomotive Emissions

The District of Columbia emission contact provided MACTEC with alternative growth factors for locomotive emissions. The growth factors provided were:

2002-2009	6.9%
2002-2012	9.9%
2002-2018	13.7%

Since the CAIR factors were combined growth and controls, the control factors developed for locomotives for Maryland (based on Federal control programs) were used to apply controls to the DC locomotive emissions. As was the case for Maryland, the control factors were "additive" and were used on the base year emission without back-calculating uncontrolled emissions since the control levels were relative to controls in place for 2002.

4.2.3 Logan (Boston) Airport Emissions

Massachusetts supplied historic and future year projections of operations at Logan Airport. The data covered the period 2000-2010. Since only one year of the period required for MANE-VU projections was included in that interval (2009), MACTEC developed estimates for 2012 and 2018 from those data by linear interpolation. Two linear interpolations were developed. The first used the entire data set (2000-2010) to develop a linear projection for 2012 and 2018 and a second using just the 2002-2010 data. For the final growth factors, MACTEC used the average of the two. These growth factors were then applied to commercial aircraft operations for Suffolk County (FIPS = 25025). The growth factors developed were:

2002-2009	1.184
2002-2012	1.22
2002-2018	1.33

No controls that would come on board for aircraft for the projection years were identified from a review of Federal programs.

4.3 NONROAD QA/QC REVIEW

Throughout the inventory development process, quality assurance steps were performed to ensure that no double counting of emissions occurred, to ensure that a full and complete inventory was developed for MANE-VU, and to make sure that projection calculations were working correctly. MACTEC performed the following QA steps on nonroad source projection inventories: (1) All final files (NONROAD only) were run through EPA's Format and Content checking software; SCC level emission summaries were prepared and evaluated to ensure that emissions were consistent with the 2002 projections and that there were no missing source categories or geographical areas.

4.4 NONROAD NIF, SMOKE, AND SUMMARY FILES

The Version 3.1 files delivered to MARAMA are shown in Table 4-1.

4.5 NONROAD EMISSION SUMMARIES

Table 4-2a shows the CO emissions by state and year for the entire nonroad sector. Table 4-2b presents the CO emission results for NONROAD model equipment only. Table 4-2c presents the CO emission results for only the aircraft, commercial marine vessel, and locomotive categories. Tables 4-3 to 4-8 present the emission results for the other criteria pollutants of interest.

Table 4-1 Nonroad Source NIF, IDA, and Summary File Names

File Name	Date	Description
MANEVU_OTB2009_NR_NIFV3_1.mdb	Oct. 23, 2006	Version 3.1 of 2009 nonroad source NIF inventory
MANEVU_OTB2012_NR_NIFV3_1.mdb	Oct. 23, 2006	Version 3.1 of 2012 nonroad source NIF inventory
MANEVU_OTB2018_NR_NIFV3_1.mdb	Oct. 23, 2006	Version 3.1 of 2018 nonroad source NIF inventory
MANEVU_OTB2009_NR_IDAV3_1.txt	Oct. 26, 2006	Version 3.1 of 2009 nonroad source inventory in SMOKE IDA format
MANEVU_OTB2012_NR_IDAV3_1.txt	Oct. 26, 2006	Version 3.1 of 2012 nonroad source inventory in SMOKE IDA format
MANEVU_OTB2018_NR_IDA3V_1.txt	Oct. 26, 2006	Version 3.1 of 2018 nonroad source inventory in SMOKE IDA format
MANEVU OTB Nonroad V3_1 State Summary.xls	Oct. 23, 2006	Spreadsheet with state totals by pollutant for all nonroad sources, NONROAD model sources, and aircraft, locomotives, and commercial marine vessels
MANEVU OTB Nonroad V3_1 State SCC Summary.xls	Oct. 23, 2006	Spreadsheet with SCC totals by state and pollutant for all nonroad sources, NONROAD model sources

Table 4-2a All Nonroad Sources OTB/OTW Annual CO Emission Projections (tons per year)

State	2002	2009	2012	2018
CT	276,773	282,788	288,061	303,764
DE	68,782	74,856	76,491	80,646
DC	18,845	20,746	21,306	22,429
ME	153,424	163,782	165,273	166,679
MD	437,400	497,276	513,737	550,795
MA	461,514	504,400	516,019	546,373
NH	130,782	142,318	143,804	147,544
NJ	704,396	753,916	777,069	831,880
NY	1,233,968	1,349,439	1,388,406	1,474,727
PA	931,978	1,031,816	1,058,256	1,119,247
RI	73,013	80,228	82,113	87,195
VT	62,248	68,360	69,003	70,074
Total	**4,553,124**	**4,969,925**	**5,099,538**	**5,401,353**

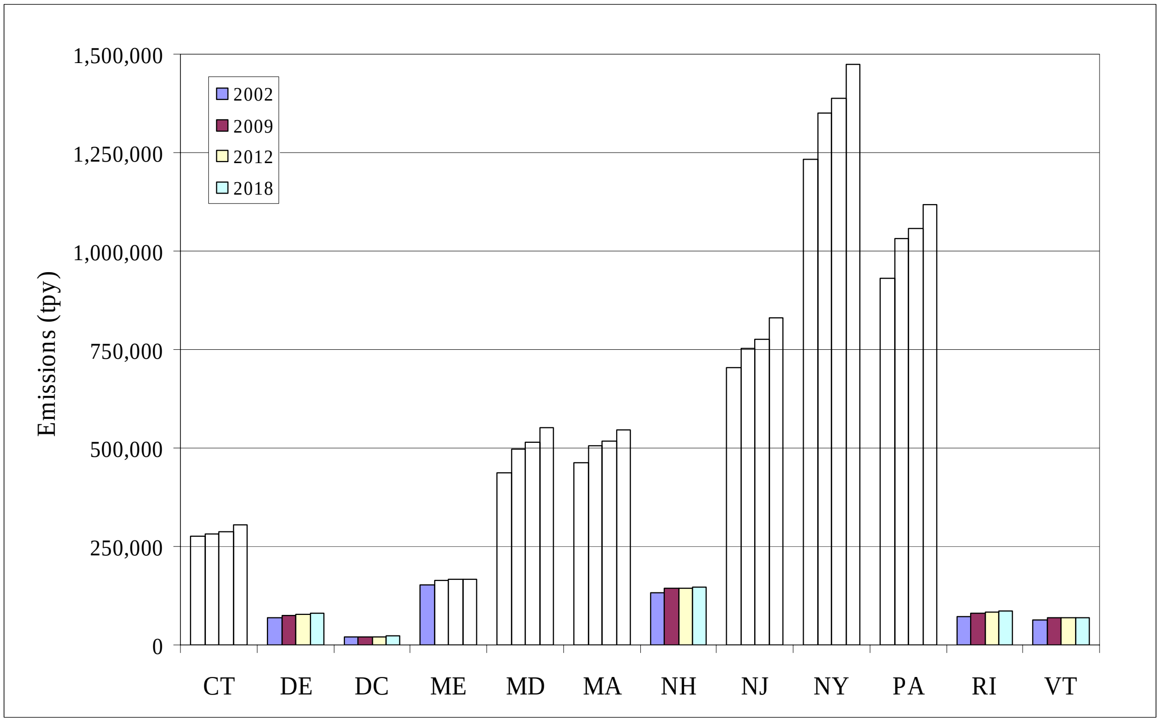


Table 4-2b NONROAD Model Sources
OTB/OTW Annual CO Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	274,388	280,253	285,415	300,931
DE	65,954	71,877	73,397	77,356
DC	18,775	20,671	21,229	22,350
ME	148,555	158,715	160,043	161,215
MD	424,777	482,312	497,806	532,970
MA	448,399	490,895	501,684	530,686
NH	128,572	139,288	140,655	144,191
NJ	692,548	741,792	764,424	818,519
NY	1,219,309	1,333,923	1,372,164	1,457,277
PA	903,168	1,003,480	1,029,045	1,088,614
RI	71,573	78,764	80,607	85,618
VT	61,732	67,802	68,421	69,456
Total	**4,457,748**	**4,869,771**	**4,994,890**	**5,289,186**

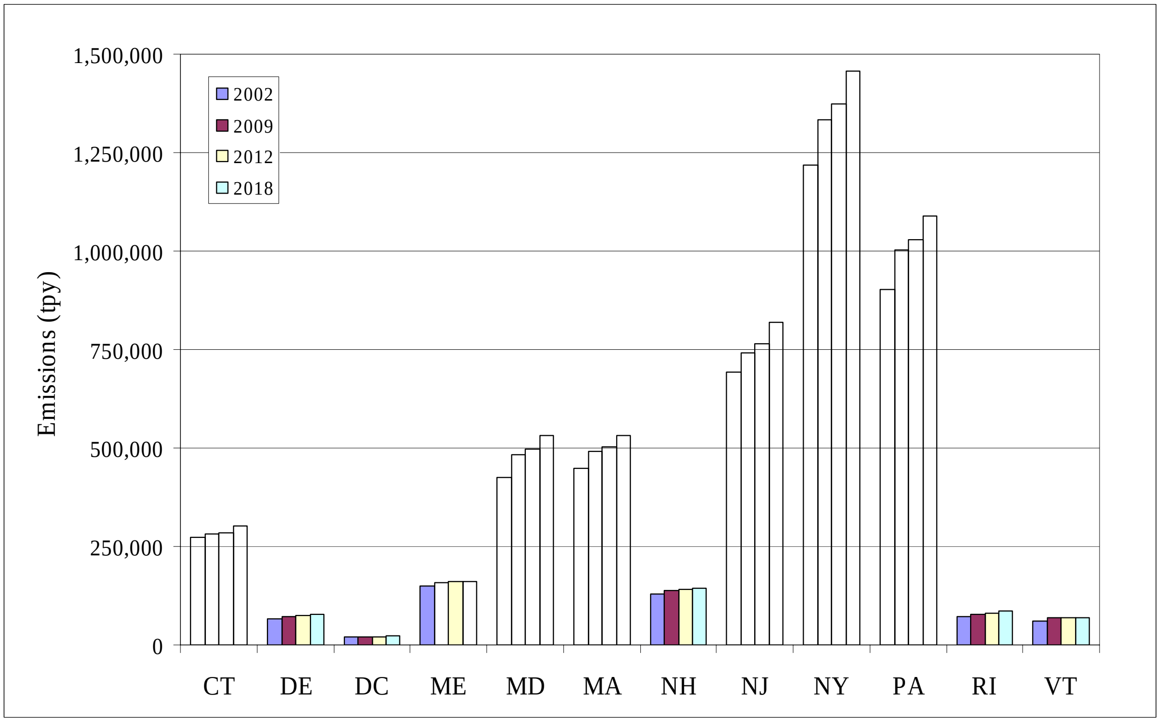


Table 4-2c Aircraft, Locomotive, and Commercial Marine Sources OTB/OTW Annual CO Emission Projections (tons per year)

State	2002	2009	2012	2018
CT	2,385	2,535	2,646	2,833
DE	2,828	2,979	3,094	3,290
DC	70	75	77	79
ME	4,868	5,067	5,230	5,464
MD	12,624	14,964	15,931	17,825
MA	13,116	13,505	14,335	15,687
NH	2,211	3,030	3,149	3,353
NJ	11,849	12,124	12,645	13,361
NY	14,660	15,516	16,242	17,450
PA	28,810	28,336	29,211	30,633
RI	1,440	1,464	1,506	1,577
VT	516	558	582	618
Total	**95,375**	**100,154**	**104,648**	**112,167**

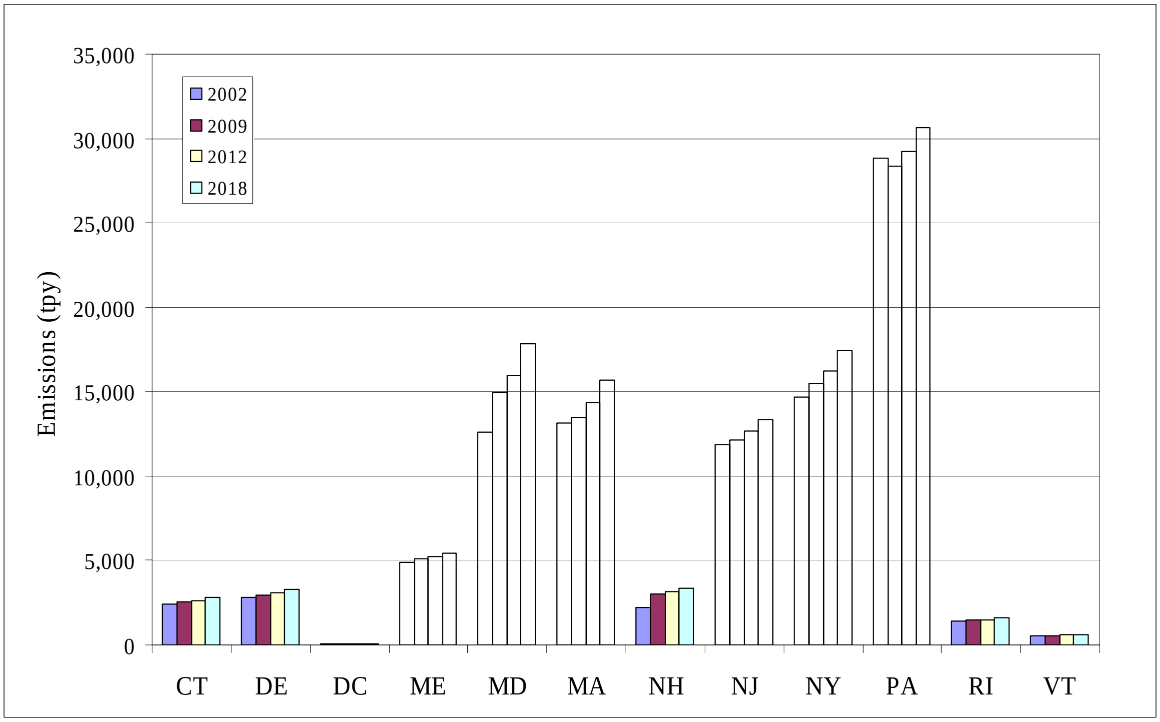


Table 4-3a All Nonroad Sources
OTB/OTW Annual NH3 Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	17	18	19	21
DE	5	6	6	7
DC	2	3	3	3
ME	11	13	14	15
MD	28	31	33	36
MA	28	31	33	36
NH	9	10	11	12
NJ	43	45	47	52
NY	79	89	94	103
PA	55	62	66	73
RI	4	4	5	5
VT	5	5	6	6
Total	**287**	**317**	**337**	**369**

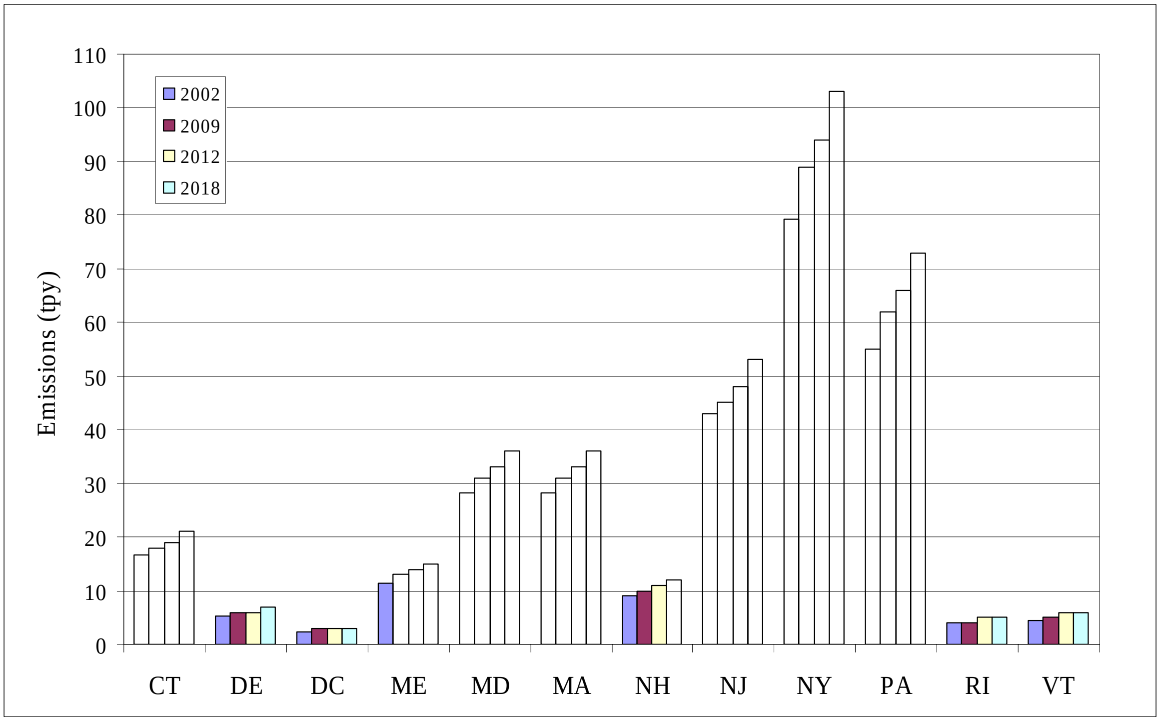


Table 4-3b NONROAD Model Sources
OTB/OTW Annual NH3 Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	17	18	19	21
DE	5	6	6	6
DC	2	3	3	3
ME	11	13	14	15
MD	28	31	33	36
MA	28	31	33	36
NH	9	10	11	12
NJ	43	45	47	52
NY	79	89	94	103
PA	55	62	66	73
RI	4	4	5	5
VT	5	5	6	6
Total	**287**	**318**	**335**	**369**

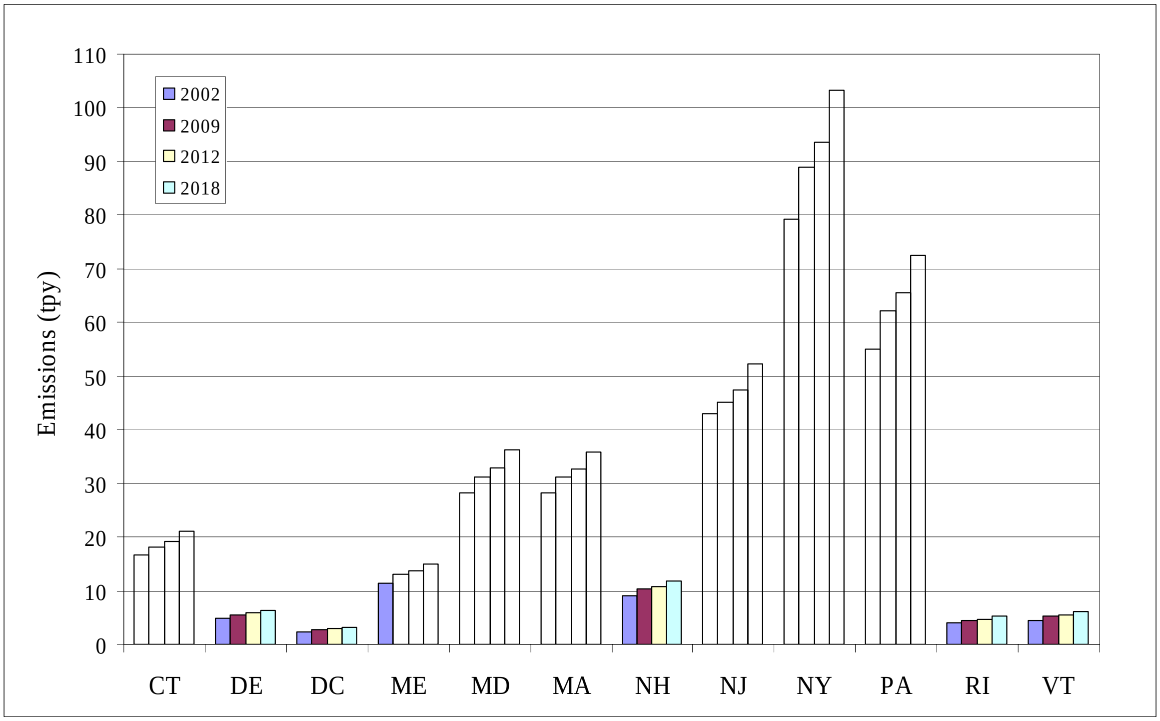


Table 4-3c Aircraft, Locomotive, and Commercial Marine Sources OTB/OTW Annual NH3 Emission Projections (tons per year)

State	2002	2009	2012	2018
CT	0	0	0	0
DE	0	0	0	0
DC	0	0	0	0
ME	0	0	0	0
MD	0	0	0	0
MA	0	0	0	0
NH	0	0	0	0
NJ	0	0	0	0
NY	0	0	0	0
PA	0	0	0	0
RI	0	0	0	0
VT	0	0	0	0
Total	**<1**	**<1**	**<1**	**<1**

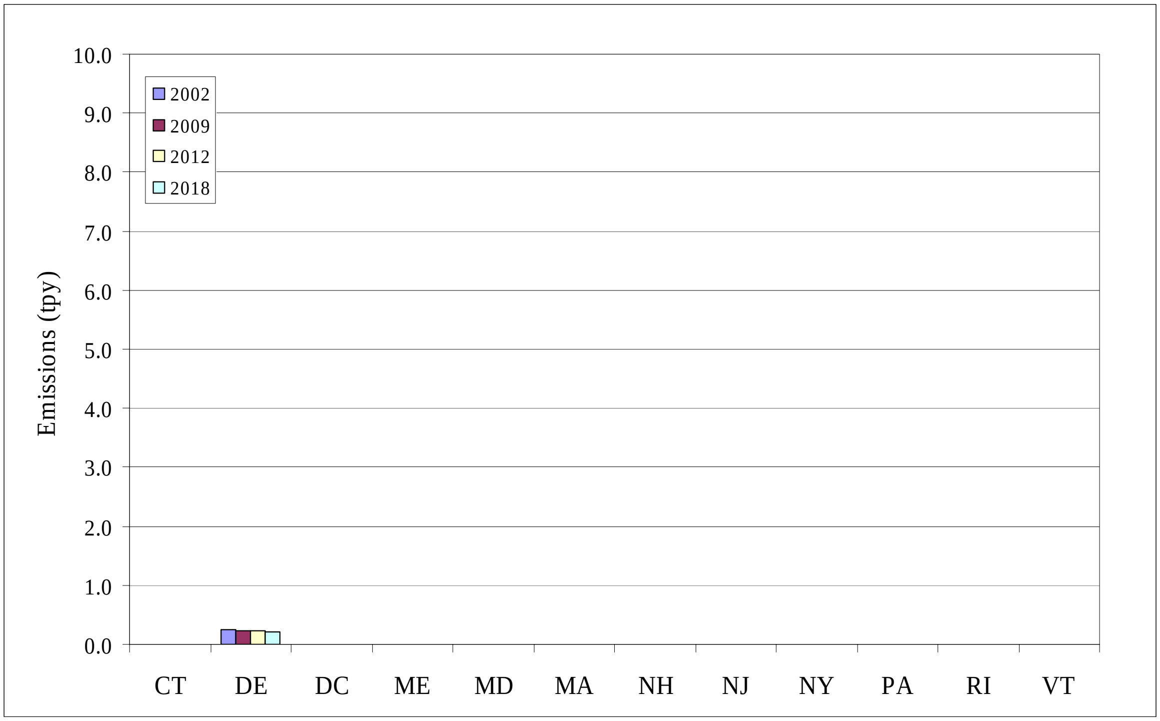


Table 4-4a All Nonroad Sources
OTB/OTW Annual NOx Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	25,460	21,512	19,316	16,233
DE	16,227	15,439	15,081	14,631
DC	3,571	2,981	2,620	1,815
ME	9,820	8,500	7,752	6,543
MD	37,472	31,762	29,058	24,257
MA	42,769	35,703	32,118	27,040
NH	9,912	8,485	7,624	6,344
NJ	63,479	52,703	48,234	41,166
NY	109,878	94,186	85,852	72,400
PA	103,824	76,105	67,818	55,771
RI	5,002	4,022	3,470	2,723
VT	4,217	3,452	2,992	2,262
Total	**431,631**	**354,850**	**321,935**	**271,185**

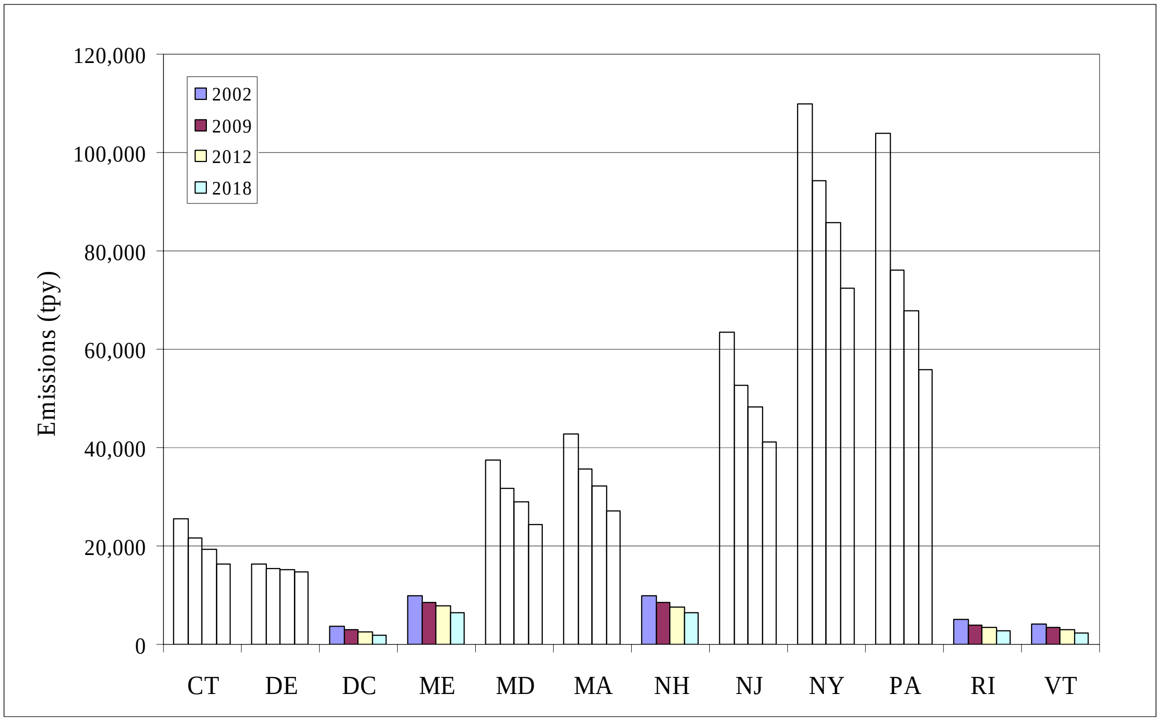


Table 4-4b NONROAD Model Sources
OTB/OTW Annual NOx Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	17,897	14,849	12,811	9,784
DE	5,798	4,755	4,108	2,966
DC	3,066	2,561	2,221	1,444
ME	8,229	6,957	6,211	4,970
MD	27,789	23,431	20,839	15,745
MA	30,047	24,606	21,274	16,096
NH	8,150	6,749	5,893	4,583
NJ	43,515	34,447	30,416	23,594
NY	78,648	66,645	58,900	45,400
PA	62,265	49,982	42,571	30,797
RI	4,564	3,624	3,066	2,294
VT	4,170	3,403	2,941	2,205
Total	**294,138**	**242,009**	**211,252**	**159,877**

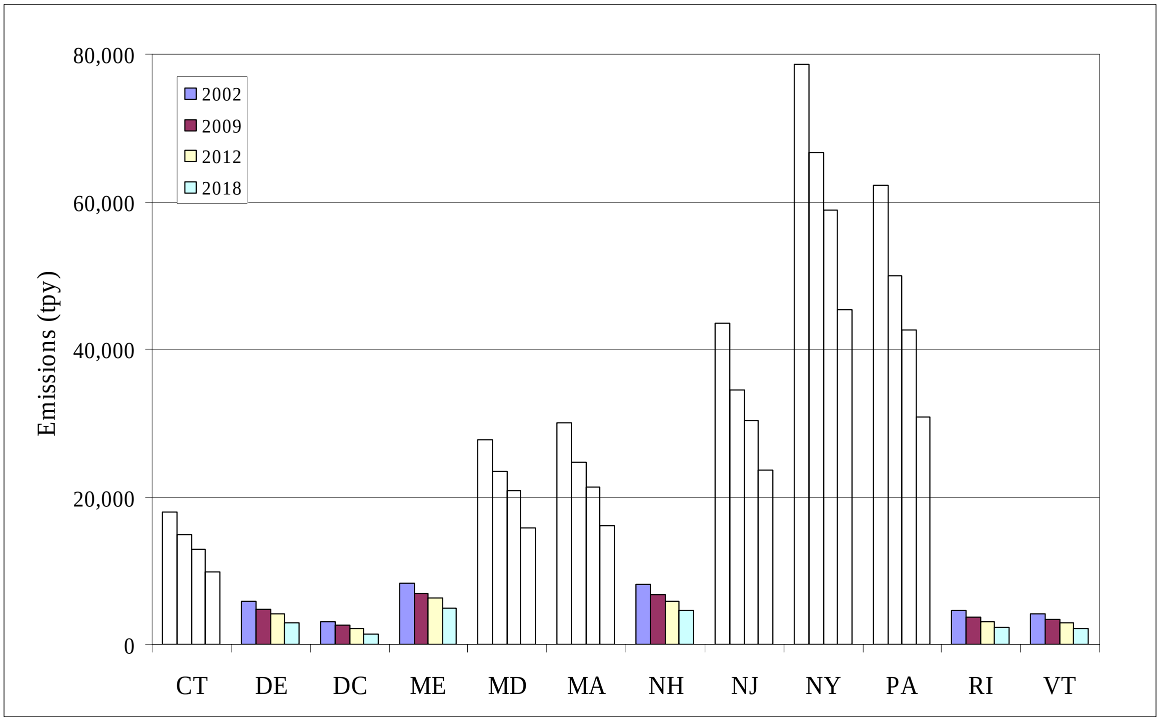


Table 4-4c Aircraft, Locomotive, and Commercial Marine Sources OTB/OTW Annual NOx Emission Projections (tons per year)

State	2002	2009	2012	2018
CT	7,563	6,663	6,505	6,449
DE	10,428	10,684	10,973	11,665
DC	505	420	399	371
ME	1,592	1,543	1,541	1,573
MD	9,683	8,331	8,219	8,512
MA	12,722	11,097	10,844	10,944
NH	1,763	1,736	1,731	1,761
NJ	19,964	18,256	17,818	17,572
NY	31,230	27,541	26,952	27,000
PA	41,559	26,123	25,247	24,974
RI	438	398	404	429
VT	47	49	51	57
Total	**137,493**	**112,841**	**110,683**	**111,308**

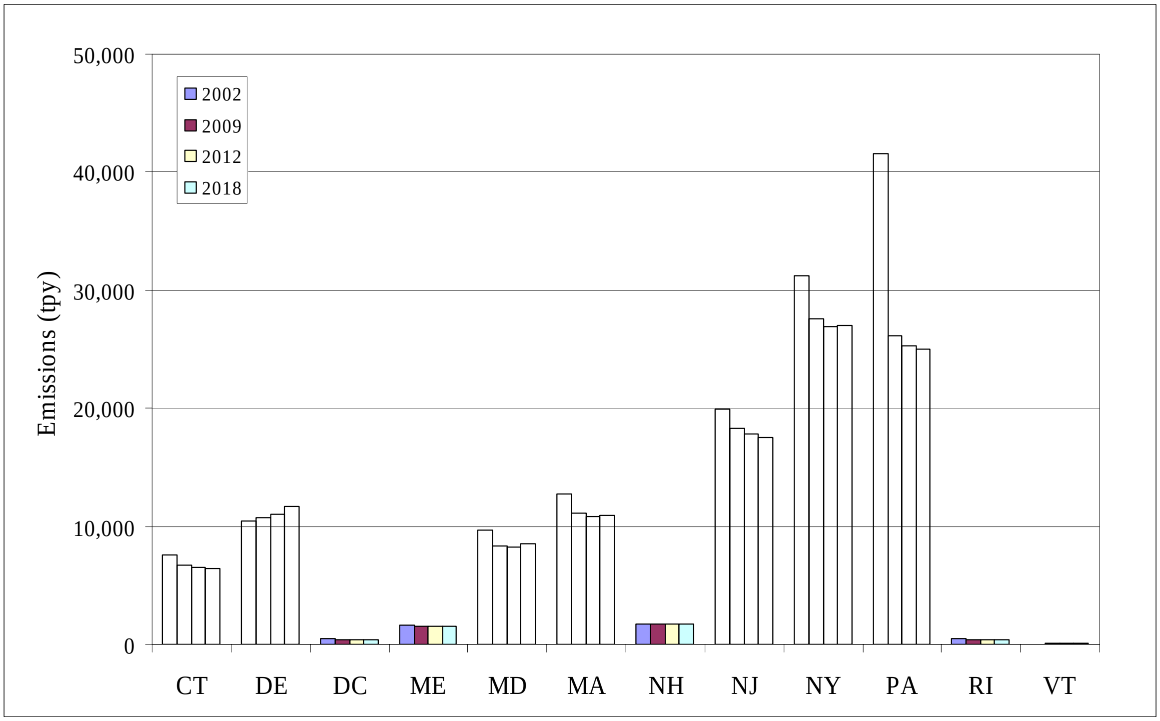


Table 4-5a All Nonroad Sources
OTB/OTW Annual PM10-PRI Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	1,952	1,642	1,532	1,236
DE	1,021	947	940	897
DC	310	235	209	135
ME	1,437	1,367	1,301	1,086
MD	4,936	4,353	4,191	3,814
MA	3,531	2,964	2,768	2,246
NH	1,058	944	881	698
NJ	5,495	4,539	4,233	3,489
NY	9,605	8,050	7,425	5,830
PA	9,738	8,501	8,112	6,949
RI	500	435	414	348
VT	530	476	439	331
Total	**40,114**	**34,453**	**32,445**	**27,059**

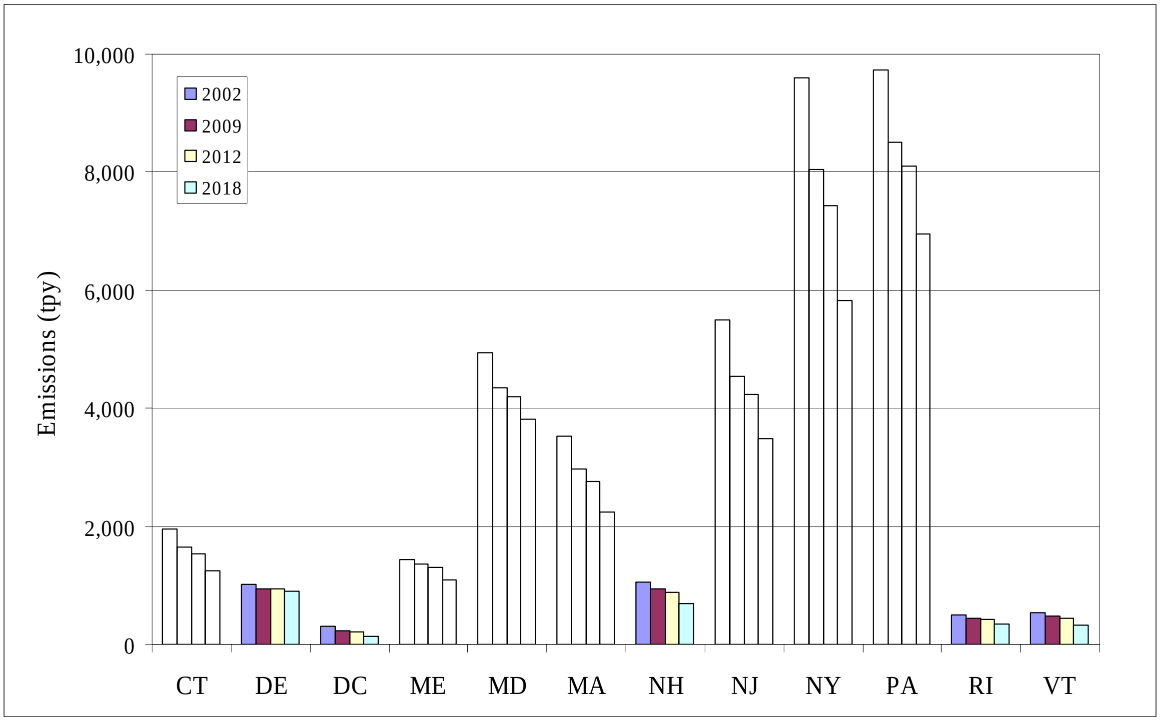


Table 4-5b NONROAD Model Sources
OTB/OTW Annual PM10-PRI Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	1,713	1,407	1,295	987
DE	570	456	414	301
DC	298	226	200	127
ME	1,204	1,119	1,039	797
MD	3,119	2,534	2,321	1,782
MA	2,887	2,370	2,176	1,640
NH	947	834	769	581
NJ	4,285	3,424	3,143	2,411
NY	8,339	6,871	6,248	4,624
PA	6,282	5,282	4,839	3,574
RI	403	337	314	244
VT	518	462	425	316
Total	**30,565**	**25,321**	**23,182**	**17,385**

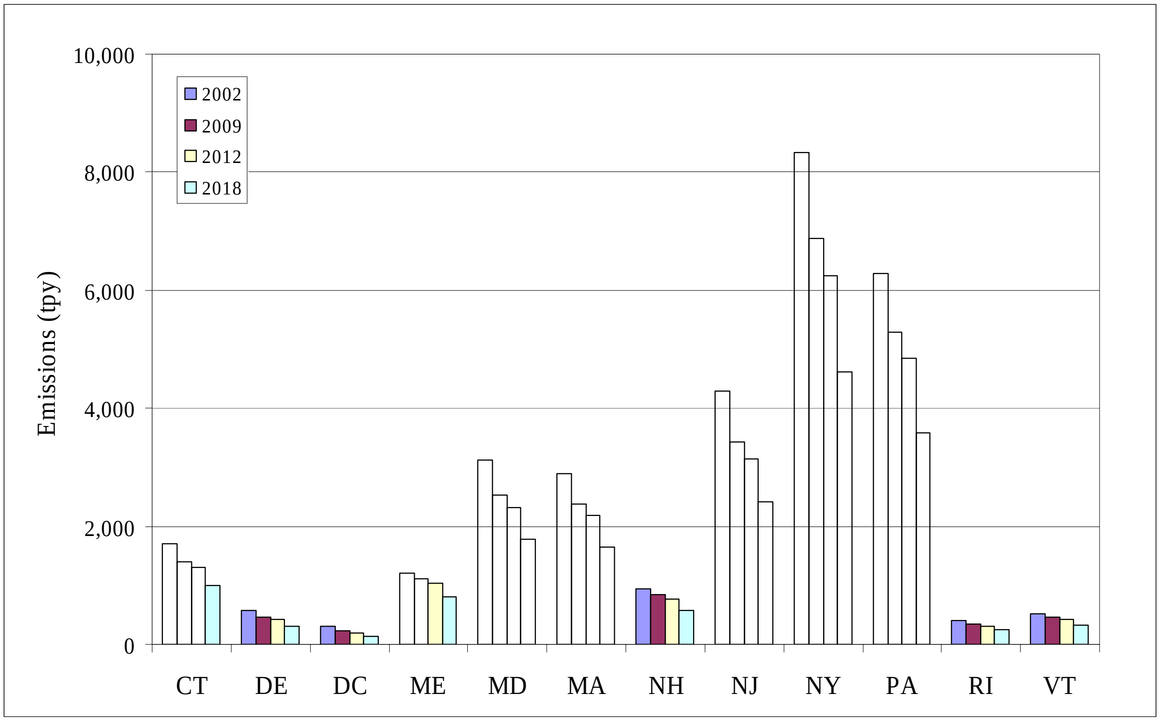


Table 4-5c Aircraft, Locomotive, and Commercial Marine Sources OTB/OTW Annual PM10-PRI Emission Projections (tons per year)

State	**2002**	**2009**	**2012**	**2018**
CT	239	235	237	249
DE	451	491	526	596
DC	12	9	9	8
ME	233	248	262	289
MD	1,817	1,819	1,870	2,032
MA	644	594	592	606
NH	111	110	112	117
NJ	1,210	1,115	1,090	1,078
NY	1,266	1,179	1,177	1,206
PA	3,456	3,219	3,273	3,375
RI	97	98	100	104
VT	12	14	14	15
Total	**9,549**	**9,132**	**9,263**	**9,674**

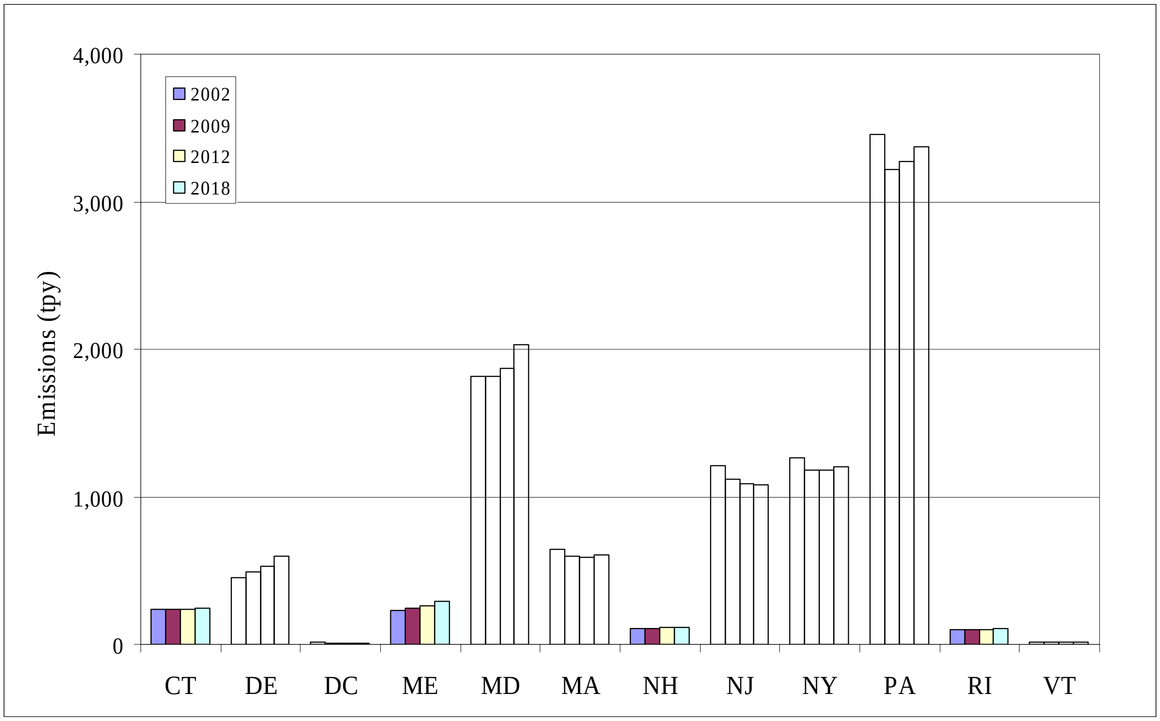


Table 4-6a All Nonroad Sources
OTB/OTW Annual PM25-PRI Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	1,794	1,508	1,408	1,135
DE	926	856	849	808
DC	299	216	192	124
ME	1,329	1,238	1,177	978
MD	4,357	3,806	3,653	3,301
MA	3,226	2,710	2,531	2,052
NH	965	861	802	634
NJ	4,997	4,113	3,829	3,143
NY	8,821	7,390	6,815	5,349
PA	8,440	7,274	6,900	5,808
RI	443	383	364	303
VT	486	436	402	303
Total	**36,084**	**30,791**	**28,922**	**23,938**

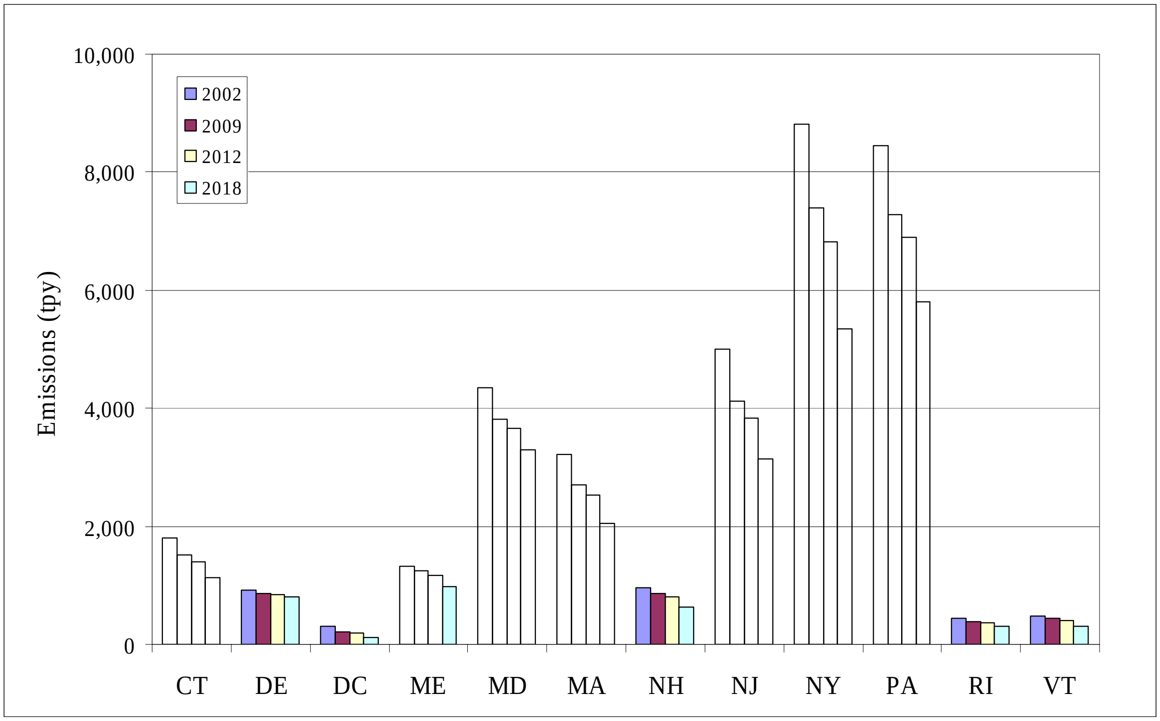


Table 4-6b NONROAD Model Sources OTB/OTW Annual PM25-PRI Emission Projections (tons per year)

State	2002	2009	2012	2018
CT	1,578	1,296	1,193	911
DE	525	420	381	277
DC	288	208	184	117
ME	1,135	1,030	956	734
MD	2,870	2,333	2,137	1,641
MA	2,659	2,184	2,005	1,512
NH	872	768	708	536
NJ	3,951	3,154	2,896	2,223
NY	7,677	6,327	5,755	4,262
PA	5,784	4,866	4,459	3,296
RI	371	311	290	226
VT	477	426	391	292
Total	**28,186**	**23,321**	**21,356**	**16,027**

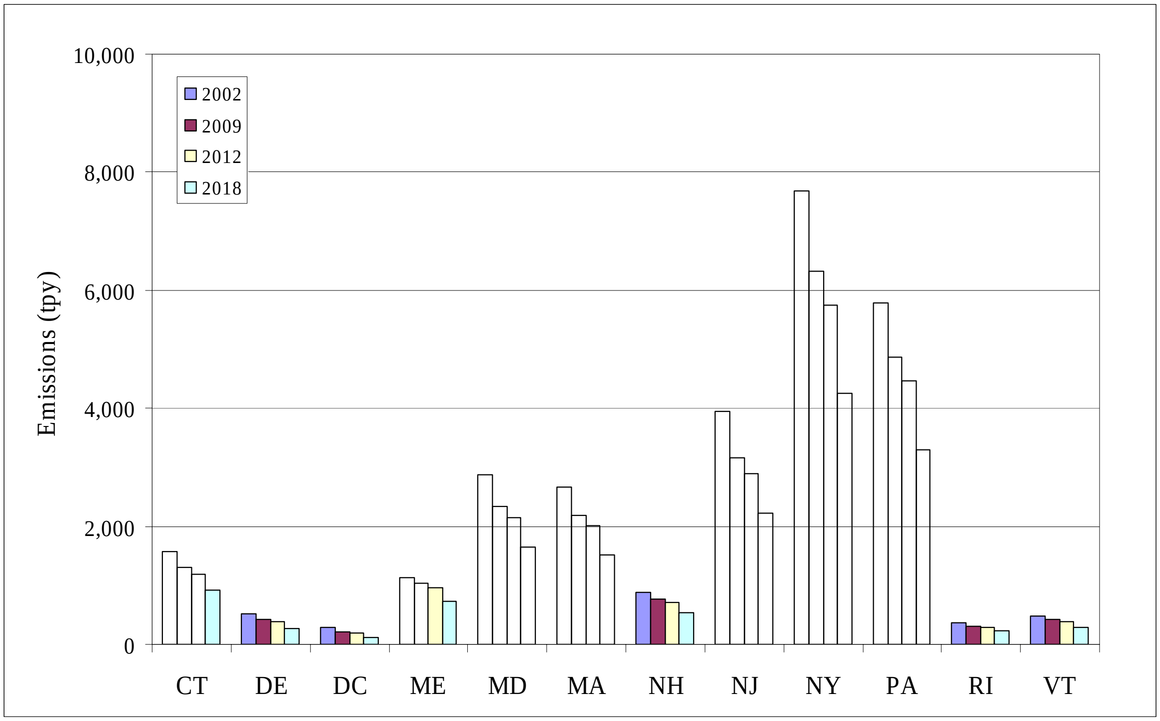


Table 4-6c Aircraft, Locomotive, and Commercial Marine Sources OTB/OTW Annual PM25-PRI Emission Projections (tons per year)

State	2002	2009	2012	2018
CT	216	212	215	224
DE	401	436	468	531
DC	11	8	8	7
ME	194	208	221	244
MD	1,487	1,473	1,516	1,660
MA	568	526	526	540
NH	94	93	94	98
NJ	1,047	959	933	920
NY	1,144	1,063	1,060	1,087
PA	2,656	2,408	2,441	2,512
RI	72	72	74	77
VT	9	10	11	11
Total	**7,898**	**7,470**	**7,566**	**7,911**

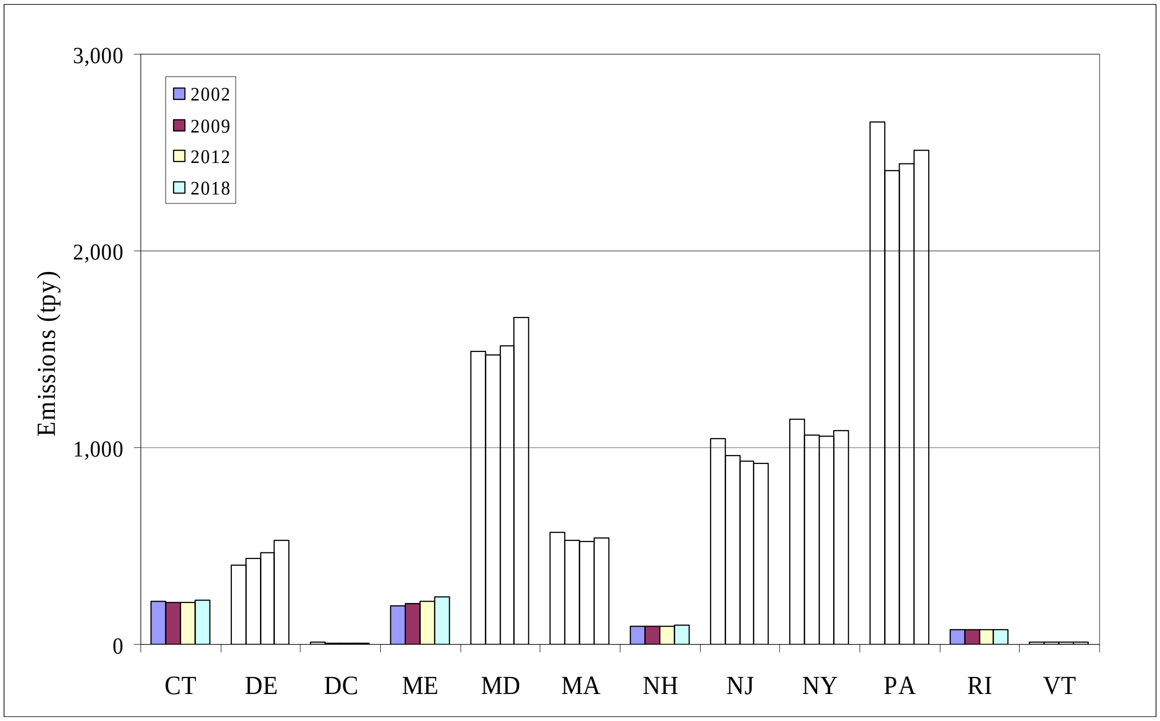


Table 4-7a All Nonroad Sources
OTB/OTW Annual SO2 Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	2,087	887	711	815
DE	3,983	2,851	2,834	3,296
DC	375	66	9	5
ME	917	201	82	82
MD	7,942	1,638	706	577
MA	3,791	983	470	442
NH	891	310	218	246
NJ	15,686	3,508	1,253	832
NY	12,920	3,387	1,724	1,686
PA	7,915	1,659	667	607
RI	377	93	42	42
VT	372	68	15	13
Total	**57,257**	**15,651**	**8,731**	**8,643**

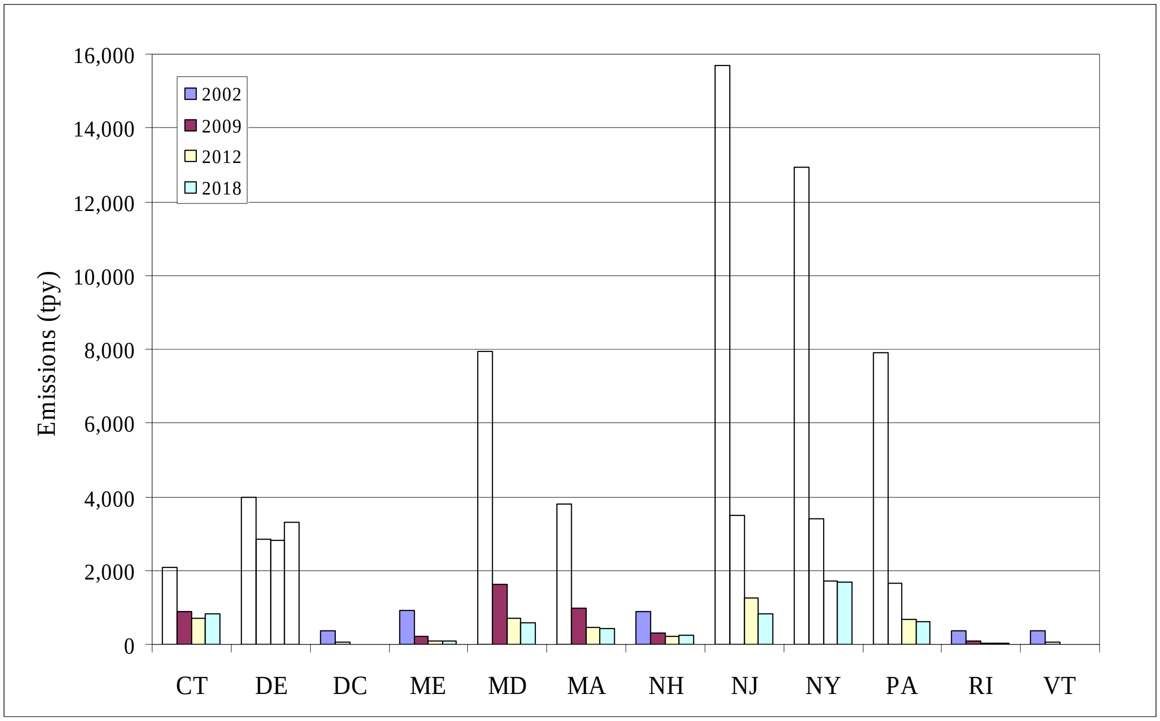


Table 4-7b NONROAD Model Sources
OTB/OTW Annual SO2 Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	1,377	249	39	28
DE	513	90	12	8
DC	341	59	6	3
ME	772	132	24	19
MD	2,569	452	63	42
MA	2,428	429	66	47
NH	673	119	20	16
NJ	3,525	607	93	67
NY	6,966	1,208	182	130
PA	5,292	917	135	92
RI	336	60	10	7
VT	368	64	10	8
Total	**25,159**	**4,387**	**661**	**467**

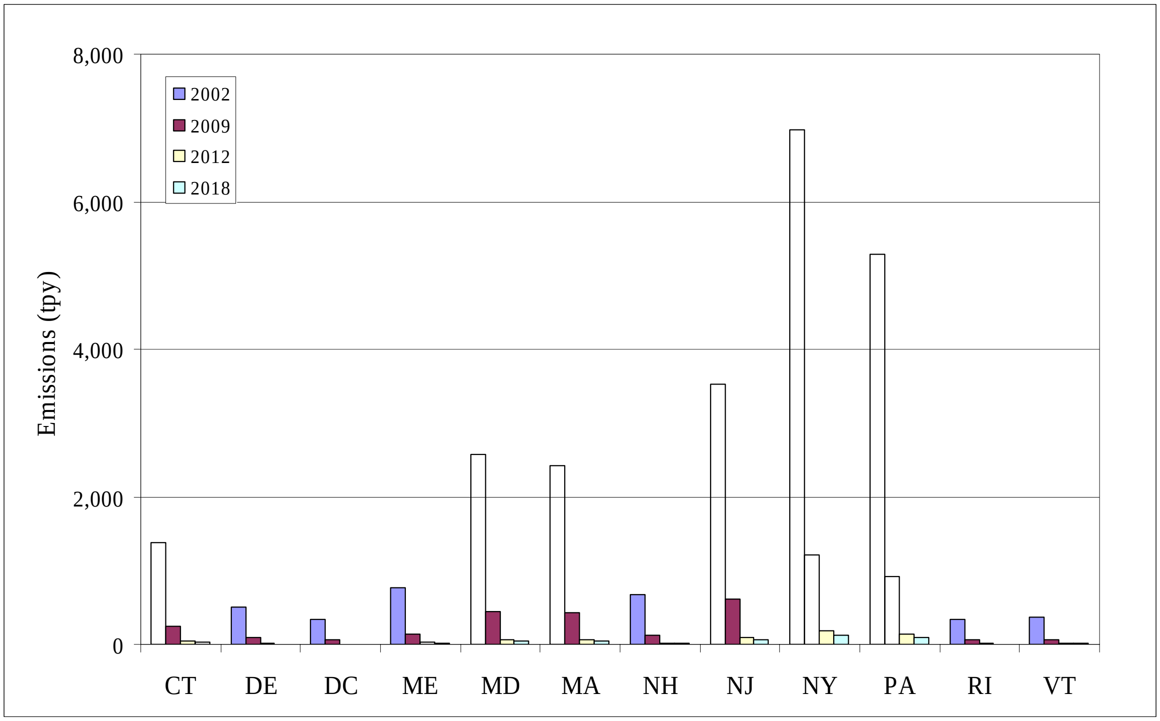


Table 4-7c Aircraft, Locomotive, and Commercial Marine Sources OTB/OTW Annual SO2 Emission Projections (tons per year)

State	2002	2009	2012	2018
CT	711	638	672	787
DE	3,470	2,761	2,822	3,288
DC	34	7	3	2
ME	145	69	58	63
MD	5,372	1,186	643	535
MA	1,363	554	404	395
NH	218	191	198	230
NJ	12,161	2,901	1,160	765
NY	5,953	2,179	1,542	1,556
PA	2,623	742	532	515
RI	42	33	32	35
VT	5	4	5	5
Total	**32,097**	**11,264**	**8,070**	**8,176**

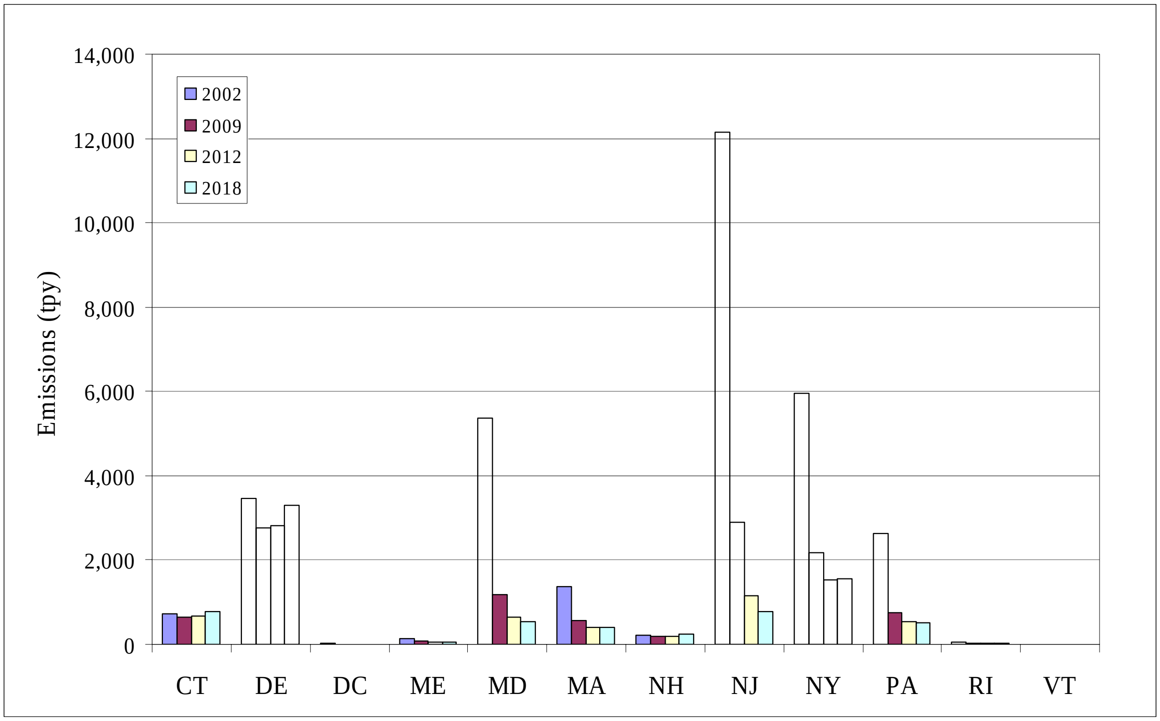


Table 4-8a All Nonroad Sources
OTB/OTW Annual VOC Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	33,880	24,910	22,657	20,694
DE	8,010	6,440	6,044	5,653
DC	2,073	1,559	1,438	1,369
ME	31,144	29,445	27,093	21,988
MD	56,330	43,260	40,266	37,969
MA	56,749	43,429	39,713	36,306
NH	22,377	19,651	17,933	15,003
NJ	83,919	62,920	57,769	53,625
NY	157,612	128,421	117,770	104,562
PA	102,331	84,744	78,630	69,956
RI	7,780	6,038	5,640	5,389
VT	10,548	10,105	9,304	7,566
Total	**572,751**	**460,922**	**424,257**	**380,080**

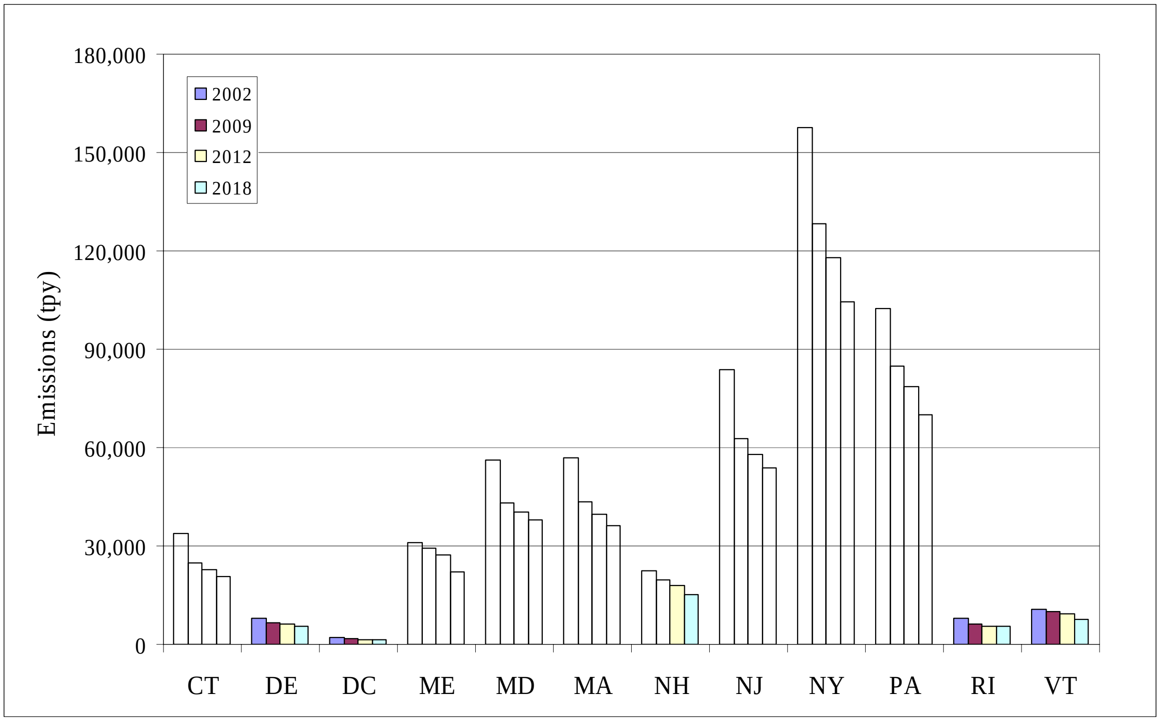


Table 4-8b NONROAD Model Sources
OTB/OTW Annual VOC Emission Projections
(tons per year)

State	2002	2009	2012	2018
CT	33,519	24,546	22,286	20,308
DE	7,531	5,943	5,533	5,115
DC	2,053	1,540	1,419	1,351
ME	30,741	29,030	26,669	21,547
MD	53,035	39,731	36,638	34,106
MA	54,836	41,473	37,706	34,185
NH	22,238	19,476	17,752	14,810
NJ	81,900	60,878	55,682	51,451
NY	155,475	126,265	115,553	102,224
PA	99,241	82,094	75,941	67,186
RI	7,699	5,956	5,556	5,302
VT	10,520	10,076	9,273	7,533
Total	**558,788**	**447,006**	**410,009**	**365,117**

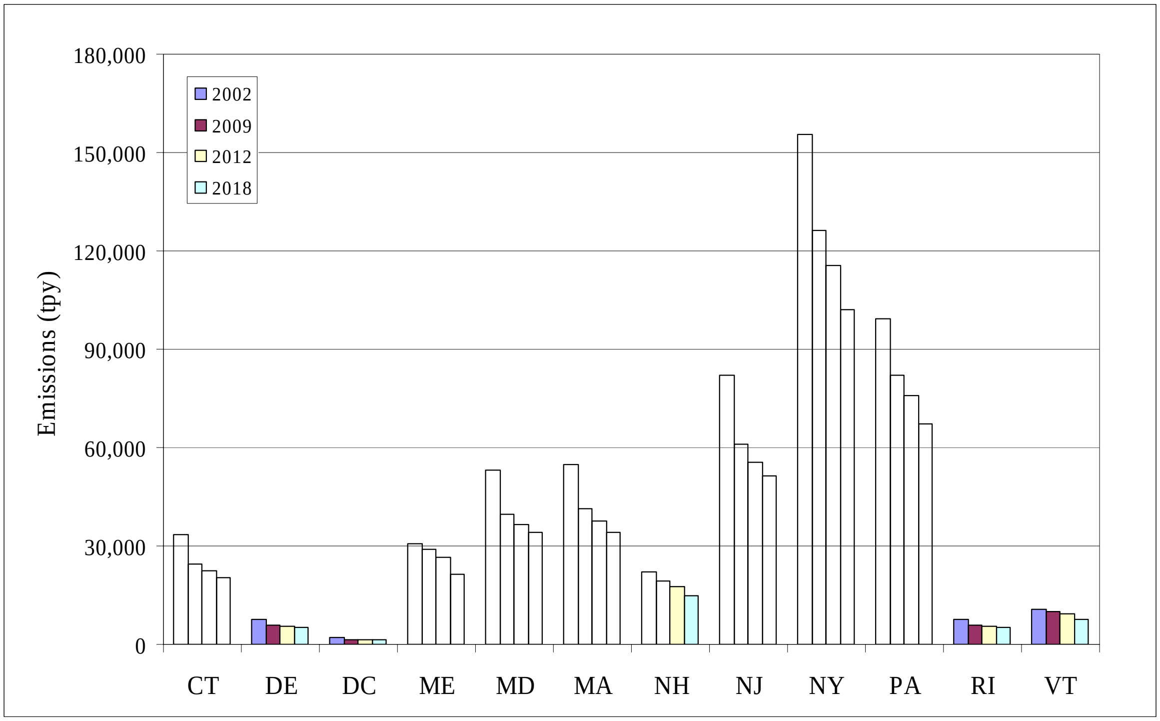
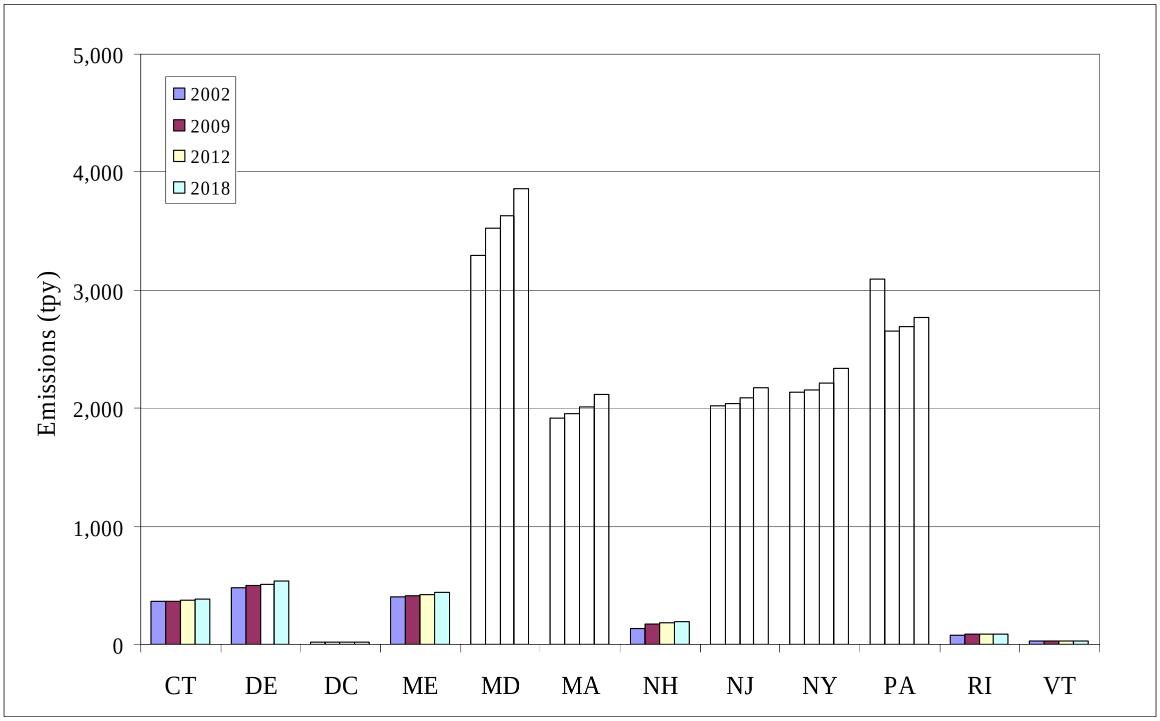


Table 4-8c Aircraft, Locomotive, and Commercial Marine Sources OTB/OTW Annual VOC Emission Projections (tons per year)

State	2002	2009	2012	2018
CT	361	364	371	386
DE	480	497	511	538
DC	20	19	19	18
ME	403	415	424	441
MD	3,295	3,529	3,628	3,863
MA	1,913	1,956	2,007	2,121
NH	139	175	181	193
NJ	2,019	2,042	2,087	2,174
NY	2,137	2,156	2,217	2,338
PA	3,090	2,650	2,689	2,770
RI	81	82	84	87
VT	27	29	31	33
Total	**13,964**	**13,916**	**14,248**	**14,963**



5.0 BEYOND-ON-THE-WAY EMISSION INVENTORY

The States are considering additional control measures as part of their planning to achieve regional haze goals and to attain the ozone and PM2.5 National Ambient Air Quality Standards (NAAQS). To accomplish this, many of the states will need to implement additional measures to reduce emissions. As such, the Ozone Transport Commission (OTC) undertook an exercise to identify a suite of additional control measures that could be used by the states in the Ozone Transport Region (OTR) in attaining their air quality goals.

Based on the analyses conducted by various OTC Workgroups, the OTC Commissioners made several recommendations at the Commissioner's meeting in Boston on June 7, 2006:

- *Memorandum of Understanding Among the States of the Ozone Transport Commission on a Regional Strategy Concerning the Integrated Control of Ozone Precursors from Various Sources*
- *Resolution 06-02 of the Ozone Transport Commission Concerning Coordination and Implementation of Regional Ozone Control Strategies for Certain Source Categories*
- *Statement of the Ozone Transport Commission Concerning Multi-Pollutant Emission Control of Electric Generating Units*
- *Resolution 06-03 of the Ozone Transport Commission Concerning Federal Guidance and Rulemaking for Nationally-Relevant Ozone Control Measures*

The Commissioners recommended that States consider emission reductions from the following source categories:

- Consumer Products
- Portable Fuel Containers
- Adhesives and Sealants Application
- Diesel Engine Chip Reflash
- Cutback and Emulsified Asphalt Paving
- Asphalt Production Plants
- Cement Kilns
- Glass Furnaces
- Industrial, Commercial, and Institutional (ICI) Boilers
- Regional Fuels
- Electric Generating Units (EGUs)

This suite of controls for the above source categories constitutes a "beyond-on-the-way" (BOTW) scenario to be used in modeling ozone, fine particles, and regional haze in the OTR and MANE-VU regions.

For the MANE-VU modeling inventory, each state was asked to complete a matrix to identify which of the above source category control measures to include and in which years the control measure should be applied. This section documents the emission reductions anticipated to result from the implementation of the above control measures based on the state recommendations for measures to include for each state, source category, and projection year. There are five subsections discussing the control measure and emission reductions for the five source category sectors: nonEGU point sources, area sources, EGUs, onroad mobile sources, and nonroad mobile sources.

5.1 NONEGU POINT SOURCES

This Section describes the analysis of the control measures to reduce emissions from non-EGU point sources. The control measures included in this analysis reduce emissions for the following pollutants and nonEGU point source categories:

- NOx measures: asphalt production plants; cement kilns; glass and fiberglass furnaces; low sulfur heating oil for commercial and institutional units; and ICI boilers (natural gas, #2 fuel oil, #4/#6 fuel oil, and coal);
- Primary PM10 and PM2.5 measure: commercial heating oil;
- SO2 measures: commercial heating oil and ICI boilers (#2 fuel oil, #4/#6 fuel oil, and coal); and
- VOC measure: adhesives and sealants application;

For the MANE-VU modeling inventory, each state was asked to complete a matrix to identify which nonEGU control measures to include and in which years the control measure should be applied. Table 5.1 summarizes the staff recommendations for NOx control measures to include in the BOTW regional modeling inventory for non-EGU source categories (except ICI boilers). Table 5.2 summarizes the staff recommendations for NOx emission reductions for ICI boilers. Tables 5.3 and 5.4 summarize the staff recommendations for control measures to include in the BOTW regional modeling inventory for SO2 and VOC emissions, respectively. The following subsections describe the emission reductions anticipated for each of the control measures.

Table 5.1 State Staff Recommendations for Control Measures to Include in BOTW Regional Modeling – NOx Emissions from NonEGU Point Sources

	Asphalt Production Plants			**Cement Kilns**			**Glass and Fiberglass Furnaces**			**Commercial & Institutional Heating Oil**		
State	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**
CT	Yes	Yes	Yes	N/A	N/A	N/A	N/A	N/A	N/A	No	No	Yes
DE	No	No	No	N/A	N/A	N/A	N/A	N/A	N/A	No	No	No
DC	Yes	Yes	Yes	N/A	N/A	N/A	N/A	N/A	N/A	No	Yes	Yes
ME	No	No	No	Yes	Yes	Yes	N/A	N/A	N/A	No	Yes	Yes
MD	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
MA	No	No	No	N/A	N/A	N/A	Yes	Yes	Yes	No	Yes	Yes
NH	No	No	No	N/A	N/A	N/A	N/A	N/A	N/A	No	No	Yes
NJ	No	Yes	Yes	N/A	N/A	N/A	No	Yes[2]	Yes[2]	No	Yes	Yes
NY	Yes	Yes	Yes	Yes[1]	Yes[1]	Yes[1]	Yes[2]	Yes[3]	Yes[3]	No	Yes	Yes
PA	No	No	No	No	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
RI	No	No	No	N/A	N/A	N/A	No	No	No	No	Yes	Yes
VT	No	No	No	N/A	N/A	N/A	N/A	N/A	N/A	No	No	No

Yes - Include emission reductions from control measure in modeling inventory
No - Do not include emission reduction from control measure in modeling inventory
N/A – No facilities of this type located in the state

1) New York specified that a 40 percent NOx reduction from cement kilns should be used.
2) New Jersey specified a 20 percent NOx reduction from glass furnaces in 2012 and a 35 percent reduction in 2018.
3) New York specified a 70 percent NOx reduction from glass furnaces beginning in 2009.

Table 5.2 State Staff Recommendations for Control Measures to Include in BOTW Regional Modeling – NOx Emissions from ICI Boilers

	ICI Boilers < 25 mmBTU/hour			**ICI Boilers 25-50 mmBtu/hour**			**ICI Boilers 50-100 mmBtu/hour**			**ICI Boilers 100-250 mmBtu/hour**			**ICI Boilers >250 mmBtu/hour (see note 7)**		
State	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**
CT	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1]	No	No	No
DE	No	No	No	No	No	No	No	No	No	Yes[4]	Yes[4]	Yes[4]	No	No	No
DC	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
ME	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
MD	No	No	No	No	No	No	No	No	No	Yes	Yes	Yes	No	No	No
MA	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
NH	No	No	No	Yes[5]	Yes[5]	Yes[5]	Yes	Yes	Yes	Yes[5]	Yes[5]	Yes[5]	No	No	No
NJ	Yes[2]	Yes[2]	Yes[2]	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	No	No	No
NY	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No
PA	No[3]	No[3]	No[3]	No[3]	No[3]	No[3]	No[3]	No[3]	No[3]	No[6]	No[6]	No[6]	No	No	No
RI	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
VT	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No

Yes - Include emission reductions from control measure in modeling inventory
No - Do not include emission reduction from control measure in modeling inventory
N/A – No facilities of this type located in the state

1) Connecticut is now pursuing adoption of model rule for boilers of all sizes at major and non-major sources
2) New Jersey specified a 5 percent reduction in 2009, 10 percent in 2012, and 10 percent in 2018
3) Pennsylvania specified no reductions since sources already covered by statewide NOx RACT regulation
4) Delaware is developing regulation for ICI boilers greater than 200 mmBtu/hour – no plans for regulating smaller units
5) New Hampshire specified a 40 percent reduction for 25-50 mmBtu/hour boilers, and a 10 percent reduction for natural gas-fired 100-250 mmBtu/hour boilers
6) Pennsylvania specified no reductions since sources in the 5-county Philadelphia area are already covered by the Small Sources of NOx regulation and do not plan on expanding the regulation outside of the corridor at this time
7) Resolution 06-02 specified the reduction for > 250mmBtu/hour boilers to be the "same as EGUs of similar size." The OTC Commissioners have not yet recommended an emission rate or percent reduction for EGUs. As a result, no reductions for ICI boilers > 250 mmBtu/hour were included in the BOTW inventory.

Table 5.3 State Staff Recommendations for Control Measures to Include in BOTW Regional Modeling – SO2 Emissions from NonEGU Point Sources

	Commercial & Institutional Heating Oil			**ICI Boilers (low sulfur fuel)**		
State	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**
CT	No	No	Yes	No	No	No
DE	No	No	No	No	No	No
DC	No	Yes	Yes	No	No	No
ME	No	Yes	Yes	No	No	No
MD	No	Yes	Yes	No	No	No
MA	No	Yes	Yes	No	No	No
NH	No	No	Yes	No	No	No
NJ	No	Yes	Yes	No	No	No
NY	No	Yes	Yes	No	No	No
PA	No	Yes	Yes	No	No	No
RI	No	Yes	Yes	No	No	No
VT	No	No	No	No	No	No

Yes - Include emission reductions from control measure in modeling inventory
No - Do not include emission reduction from control measure in modeling inventory

Table 5.4 State Staff Recommendations for Control Measures to Include in BOTW Regional Modeling – VOC Emissions from NonEGU Point Sources

	Adhesives and Sealants Application		
State	**2009**	**2012**	**2018**
CT	Yes	Yes	Yes
DE	Yes	Yes	Yes
DC	Yes	Yes	Yes
ME	Yes	Yes	Yes
MD	Yes	Yes	Yes
MA	Yes	Yes	Yes
NH	No	Yes	Yes
NJ	No[1]	No[1]	No[1]
NY	Yes	Yes	Yes
PA	Yes	Yes	Yes
RI	Yes	Yes	Yes
VT	No	No	No

Yes - Include emission reductions from control measure in modeling inventory
No - Do not include emission reduction from control measure in modeling inventory

1) New Jersey indicated that the reductions from the adhesives and sealants application control measure should only apply to area source - no reductions for point sources (SCC 4-02-007-xx) were included due to inventory double-counting issues, not due to rule change issues.

5.1.1 Adhesives and Sealants Application

The OTC 2006 model rule for adhesives and sealants is based on the reasonably available control technology (RACT) and best available retrofit control technology (BARCT) determination by the California Air Resources Board (CARB) developed in 1998. Adhesive and sealant emission sources are classified as both point sources and area sources. About 96 percent of adhesive and sealant VOC emissions in the OTC states fall into the area source category. The remaining four percent of the VOC emissions are included in the point source inventory.

The emission reduction benefit estimation methodology is based on information developed and used by CARB for their RACT/BARCT determination in 1998. For point sources, we first identified those sources that were applying adhesives and sealants (using the source classification code of 4-02-007-xx, adhesives application). Next, we reviewed the MANEVU inventory to determine whether these sources had existing capture and control systems. Most of the sources did not have control information in the NIF database. However, several sources reported capture and destruction efficiencies in the 70 to 99 percent range, with a few sources reporting capture and destruction efficiencies of 99+ percent. Sources with existing control systems that exceeded an 85 percent overall capture and destruction efficiency would comply with the OTC 2006 model rule provision for add-on air pollution control equipment; therefore, no additional reductions were calculated for these sources. For point sources without add-on control equipment, we used the 64.4 percent reduction based on the CARB determination.

5.1.2 Asphalt Production Plants

In Resolution 06-02, the OTC Commissioners recommended that OTC member states pursue as necessary and appropriate state-specific rulemakings or other implementation methods to establish emission reduction percentages, emission rates or technologies that would result in about a 35 percent reduction in NOx emissions. The reductions estimated for this category only include emissions included in the MANE-VU point source emission inventory. Only emissions from major point sources are typically included in the MANE-VU point source database. Emissions from non-major sources are not explicitly contained in the area source inventory; rather, the emissions from non-major asphalt plants are likely lumped together in the general area source industrial and commercial fuel use category. Therefore, there is some uncertainty regarding the actual reductions that will occur as since minor sources are not specifically identified in the MANE-VU inventory.

5.1.3 Cement Kilns

In Resolution 06-02, the OTC Commissioners recommended that OTC member states pursue as necessary and appropriate state-specific rulemakings or other implementation methods to establish emission reduction percentages, emission rates or technologies that would result in about a 60 percent reduction in NOx emissions from uncontrolled levels. Cement kilns were already included in Phase I of the NO_x SIP call. Emission reductions resulting from the NOx SIP call were accounted for in the 2009 OTB inventory. For the cement kilns in Maryland and New York, a default control efficiency value of 25 percent was applied to account for the reductions expected from the NOx SIP call. For the cement kilns in Pennsylvania, the state provided their best estimates of the actual control efficiency expected for each kiln after the NOx SIP Call. There is a cement kiln in Maine, but it is not subject to the NOx SIP call. To calculate the additional reductions from the OTC 2006 Control Measure, MACTEC back calculated uncontrolled emissions from the 2009 base year inventory based on the controls applied to account for the NOx SIP Call. Once the uncontrolled emissions were calculated, MACTEC applied the 60 percent emission reduction guideline recommended by the OTC Commissioners, except for the kilns in New York. Staff from New York indicated that a 40 percent emission reduction should be used for modeling purposes.

5.1.4 Glass and Fiberglass Furnaces

In Resolution 06-02, the OTC Commissioners recommended that OTC member states pursue as necessary and appropriate state-specific rulemakings or other implementation methods to establish emission reduction percentages, emission rates or technologies that would result in about an 85 percent reduction in NOx emissions from uncontrolled levels. The NOx emission reduction benefit was calculated by applying an 85 percent reduction to the projected 2009 base inventory, except in New Jersey and New York. New Jersey specified a 20 percent NOx reduction from glass furnaces in 2012 and a 35 percent reduction in 2018. New York specified a 70 percent NOx reduction from glass furnaces beginning in 2009. The estimated 85% reductions does not take into account existing controls at the facilities. The OTC states are currently working with the glass industry to obtain additional data to better identify the controls already in place. This will allow for a better calculation of the emission reduction benefits.

5.1.5 Industrial, Commercial, and Institutional Boilers

In Resolution 06-02, the OTC Commissioners recommended that OTC member states pursue as necessary and appropriate state-specific rulemakings or other implementation methods to establish emission reduction percentages, emission rates or technologies for ICI boilers based on guidelines that varied by boiler size and fuel type. Specifically, the following guidelines were provided:

	NOx Reduction from 2009 Base Emissions by Fuel Type			
Boiler Size (mmBtu/hour)	**Natural Gas**	**#2 Fuel Oil**	**#4/#6 Fuel Oil**	**Coal**
< 25	10	10	10	10
25 to 50	50	50	50	50*
50 to 100	10	10	10	10*
100 to 250	75	40	40	40*
>250	**	**	**	**

* Resolution 06-02 did not specify a percent reduction for coal; for modeling purposes, the same percent reduction specified for #4/#6 fuel oil was used for coal

** Resolution 06-02 specified the reduction for > 250mmBtu/hour boilers to be the "same as EGUs of similar size." The OTC Commissioners have not yet recommended an emission rate or percent reduction for EGUs. As a result, no reductions for ICI boilers > 250 mmBtu/hour were included in the BOTW inventory.

Since the above guidelines vary by boiler size and fuel type, the specific percent reduction applied to an individual source depends on the SCC and design capacity of the source. The SCC identifies the fuel type, while the design capacity identifies the boiler size. In many cases, the design capacities in the MANE-VU NIF database were missing. MACTEC used the following hierarchy in filling in gaps where design capacities were missing.

- Use the design capacity field from the NIF EU table, if available;
- Use the design capacities provided by State/local agencies to fill in the data gaps (Allegheny County, District of Columbia, Maryland, New Jersey, Philadephia County);
- Use design capacity as reported either the Unit Description field in the NIF EU table or the Process Description field from the NIF EP table, if available;
- Use design capacity from the source's Title V permit, if the Title V permit was on-line;
- Use the SCC description to determine the design capacity (for example, SCC 1-02-006-01 describes a >100 mmBtu/hr natural gas-fired boiler, SCC 1-02-006-02 describes a 10-100 mmBtu/hr natural gas-fired boiler)

After performing this gap-filling exercise, MACTEC was able to assign over 97 percent of the NOx emissions to a specific boiler size range. For the remaining sources where MACTEC could not determine the boiler size (which accounted for only 3 percent of the NOx emissions), MACTEC assumed that these boilers were < 25 mmBtu/hr.

5.1.6 Commercial and Institutional Heating Oil

The BOTW control measure for heating oil is based on NESCAUM's report entitled "Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs and Implementation Issues." NESCAUM estimates that reducing the sulfur content of heating oil from 2,500 ppm to 500 ppm lowers SO2 emissions by 75 percent, PM emissions by 80 percent, NOx emissions by 10 percent. The 500 ppm sulfur heating oil is not expected to available on a widespread basis until 2012 at the earliest. These percent reductions were applied to commercial distillate oil category (SCC 1-03-005-xx and 1-05-002-05). These percent reductions were applied based on the state's recommendations in the matrix which identifies control measures to include and in which years the control measure should be accounted for in the modeling inventory.

5.1.7 BOTW NonEGU Point Source NIF, SMOKE, and Summary Files

The Version 3.1 file names and descriptions delivered to MARAMA are shown in Table 5-5.

Table E-1 shows the anticipated percent reductions by SCC and year for the nonEGU point source BOTW control measures.

5.1.8 BOTW NonEGU Point Source Emission Summaries

Emission summaries by state, year, and pollutant are presented in Tables 5-6 through 5-12 for CO, NH3, NOx, PM10-PRI, PM25-PRI, SO2, and VOC, respectively.

Table 5-5 BOTW NonEGU Point Source NIF, IDA, and Summary File Names

File Name	Date	Description
MANEVU_BOTW2009_NonEGU_NIFV3_1.mdb	Dec. 4, 2006	Version 3.1 of 2009 BOTW nonEGU source NIF inventory
MANEVU_BOTW2012_NonEGU_NIFV3_1.mdb	Dec. 4, 2006	Version 3.1 of 2012 BOTW nonEGU source NIF inventory
MANEVU_BOTW2018_NonEGU_NIFV3_1.mdb	Dec. 4, 2006	Version 3.1 of 2018 BOTW nonEGU source NIF inventory
MANEVU_BOTW2009_NonEGU_IDAV3_1.txt	Nov. 22, 2006	Version 3.1 of 2009 BOTW nonEGU source inventory in SMOKE IDA format
MANEVU_BOTW2012_NonEGU_IDAV3_1.txt	Nov. 22, 2006	Version 3.1 of 2012 BOTW nonEGU source inventory in SMOKE IDA format
MANEVU_BOTW2018_NonEGU_IDA3V_1.txt	Nov. 22, 2006	Version 3.1 of 2018 BOTW nonEGU source inventory in SMOKE IDA format
MANEVU OTB BOTW NonEGU V3_1 State Summary.xls	Nov. 22, 2006	Spreadsheet with state totals by pollutant for all nonEGU sources
MANEVU OTB BOTW NonEGU V3_1 State SCC Summary.xls	Dec. 4, 2006	Spreadsheet with SCC totals by state and pollutant for all nonEGU sources.

Table 5-6 NonEGU Point Sources
OTB/OTW and BOTW Annual CO Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	2,157	2,251	2,251	2,306	2,306	2,415	2,415
DE	8,812	9,037	9,037	8,748	8,748	8,651	8,651
DC	247	283	283	299	299	327	327
ME	9,043	10,147	10,147	10,467	10,467	11,433	11,433
MD	94,536	104,012	104,012	111,174	111,174	141,342	141,342
MA	10,793	12,027	12,027	12,552	12,552	13,426	13,426
NH	774	858	858	871	871	907	907
NJ	8,209	10,076	10,076	10,806	10,806	12,244	12,244
NY	53,259	61,411	61,411	65,541	65,541	78,876	78,876
PA	105,815	116,430	116,430	121,251	121,251	140,908	140,908
RI	1,712	1,764	1,764	1,821	1,821	1,927	1,927
VT	220	250	250	254	254	267	267
Total	**295,577**	**328,546**	**328,546**	**346,090**	**346,090**	**412,723**	**412,723**

No BOTW controls were considered for CO.

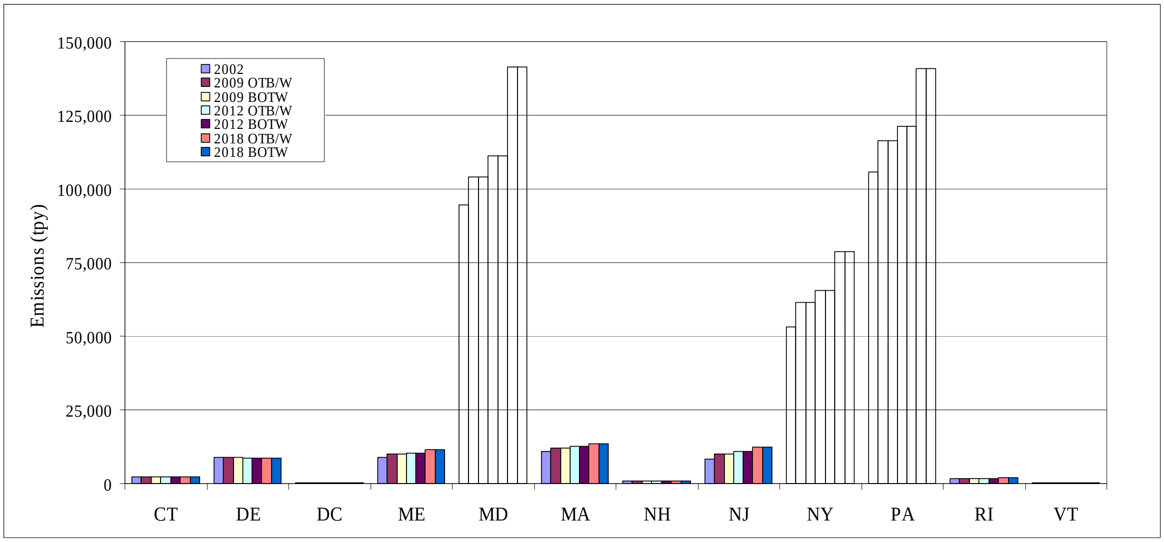


Table 5-7 NonEGU Point Sources
OTB/OTW and BOTW Annual NH3 Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	0	0	0	0	0	0	0
DE	153	145	145	138	138	134	134
DC	4	5	5	5	5	5	5
ME	700	796	796	809	809	859	859
MD	305	347	347	366	366	410	410
MA	462	510	510	521	521	563	563
NH	37	46	46	50	50	60	60
NJ	0	0	0	0	0	0	0
NY	1,027	1,081	1,081	1,128	1,128	1,296	1,296
PA	1,170	1,307	1,307	1,363	1,363	1,591	1,591
RI	58	64	64	68	68	68	68
VT	0	0	0	0	0	0	0
Total	**3,916**	**4,301**	**4,301**	**4,448**	**4,448**	**4,986**	**4,986**

No BOTW controls were considered for NH3.

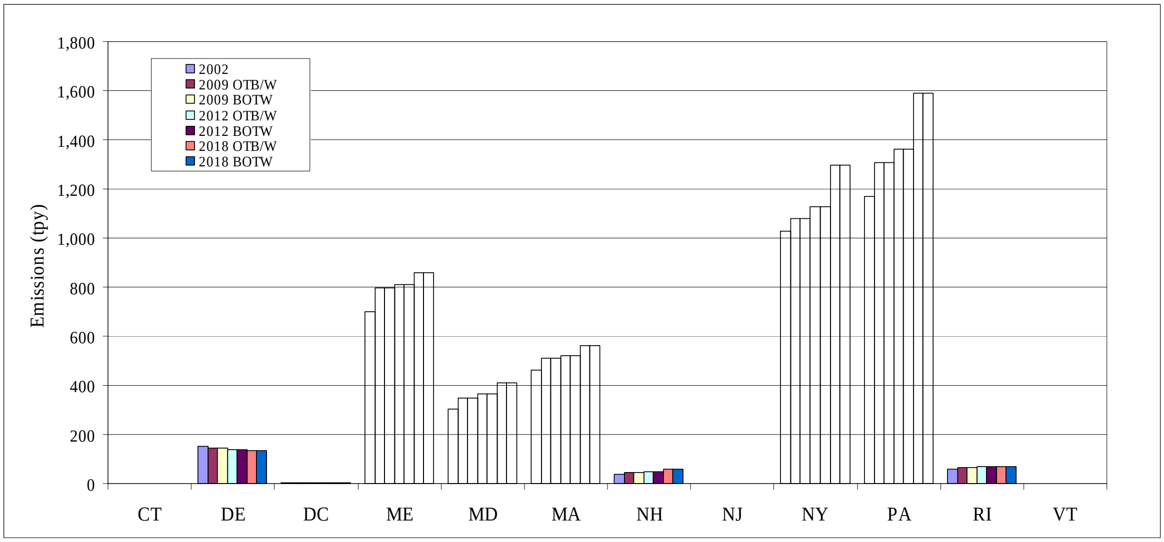


Table 5-8 NonEGU Point Sources
OTB/OTW and BOTW Annual NOx Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	6,773	7,236	6,820	7,465	7,047	7,921	7,501
DE	4,372	4,076	4,076	4,135	4,135	4,246	4,246
DC	480	548	548	577	577	627	627
ME	12,108	14,285	12,914	14,661	13,183	15,753	14,137
MD	21,940	19,401	16,015	20,399	16,819	22,797	18,888
MA	18,292	20,603	20,047	21,372	20,768	23,040	22,301
NH	1,188	1,384	1,120	1,394	1,131	1,435	1,169
NJ	15,812	16,498	16,463	17,091	15,901	18,805	17,464
NY	34,253	33,648	28,529	34,586	29,256	37,133	31,305
PA	89,136	89,932	76,215	93,526	72,779	103,137	79,186
RI	2,308	2,449	2,449	2,471	2,471	2,442	2,442
VT	386	462	462	460	460	466	466
Total	**207,048**	**210,522**	**185,658**	**218,137**	**184,527**	**237,802**	**199,732**

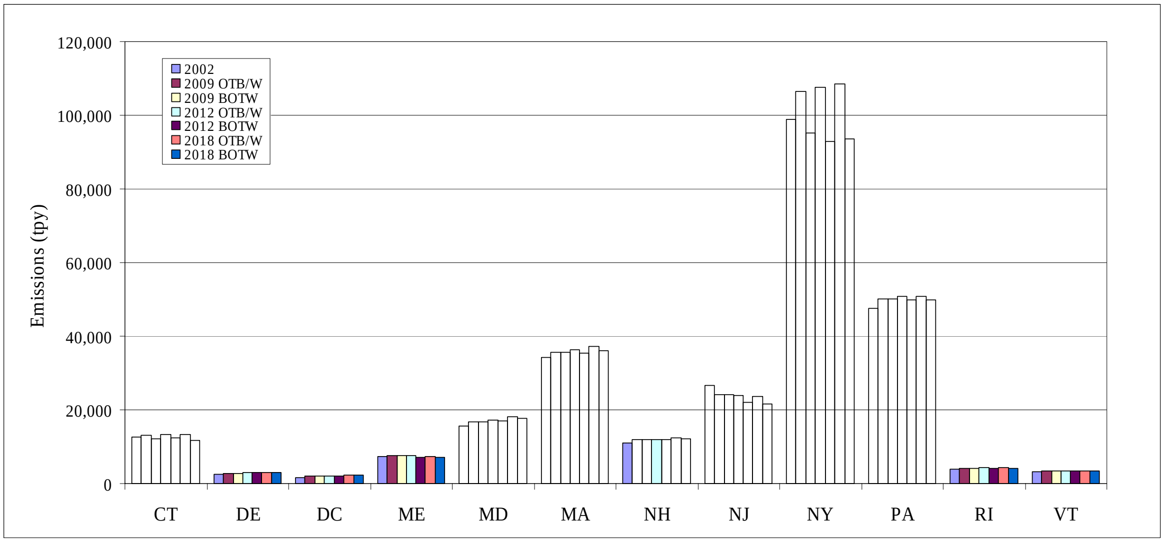


Table 5-9 NonEGU Point Sources
OTB/OTW and BOTW Annual PM10-PRI Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	990	1,035	1,035	1,058	1,058	1,106	1,104
DE	1,820	1,486	1,486	1,475	1,475	1,487	1,487
DC	157	178	178	186	182	198	194
ME	6,120	7,088	7,088	7,133	7,114	7,496	7,477
MD	4,739	4,797	4,797	5,040	5,039	5,828	5,827
MA	4,212	5,006	5,006	5,088	5,004	5,314	5,227
NH	918	1,084	1,084	1,097	1,097	1,129	1,129
NJ	3,439	4,205	4,205	4,417	4,412	4,959	4,953
NY	5,072	5,221	5,221	5,444	5,395	6,098	6,048
PA	23,282	25,169	25,169	26,307	26,258	29,516	29,466
RI	296	333	333	331	318	330	316
VT	235	267	267	272	272	296	296
Total	**51,280**	**55,869**	**55,869**	**57,848**	**57,624**	**63,757**	**63,524**

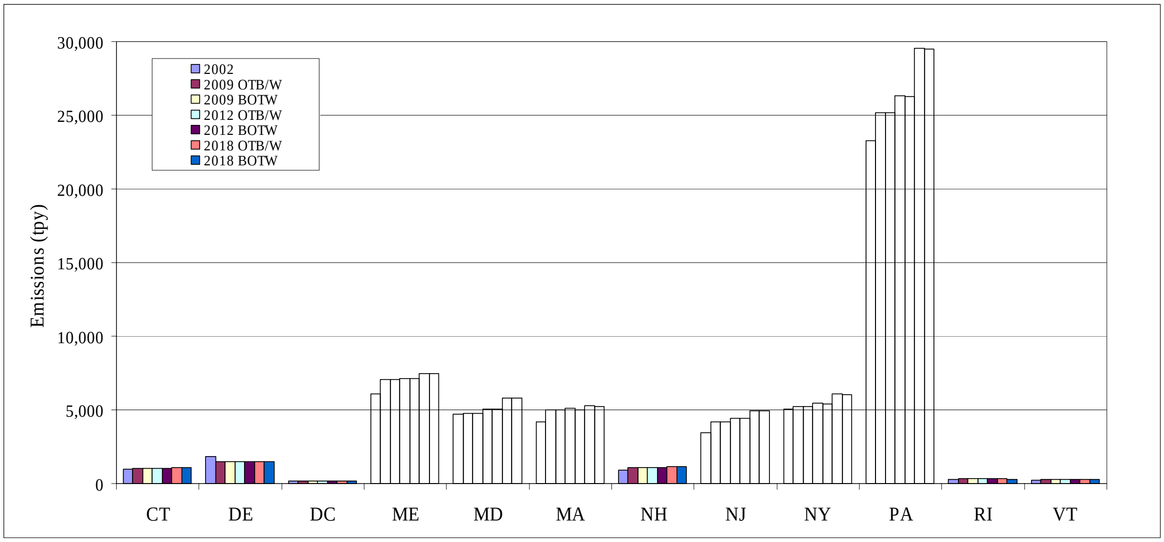


Table 5-10 NonEGU Point Sources
OTB/OTW and BOTW Annual PM25-PRI Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	822	871	871	894	894	939	937
DE	1,606	1,256	1,256	1,245	1,245	1,254	1,254
DC	128	145	145	152	149	164	161
ME	4,899	5,675	5,675	5,690	5,678	5,935	5,922
MD	2,772	2,861	2,861	3,011	3,010	3,503	3,501
MA	2,953	3,554	3,554	3,574	3,510	3,660	3,594
NH	857	1,008	1,008	1,021	1,021	1,052	1,052
NJ	2,947	3,588	3,588	3,764	3,760	4,234	4,230
NY	3,355	3,535	3,535	3,688	3,646	4,161	4,117
PA	12,360	13,578	13,578	14,159	14,114	15,878	15,831
RI	180	200	200	198	188	194	184
VT	198	226	226	229	229	246	246
Total	**33,077**	**36,497**	**36,497**	**37,625**	**37,444**	**41,220**	**41,029**

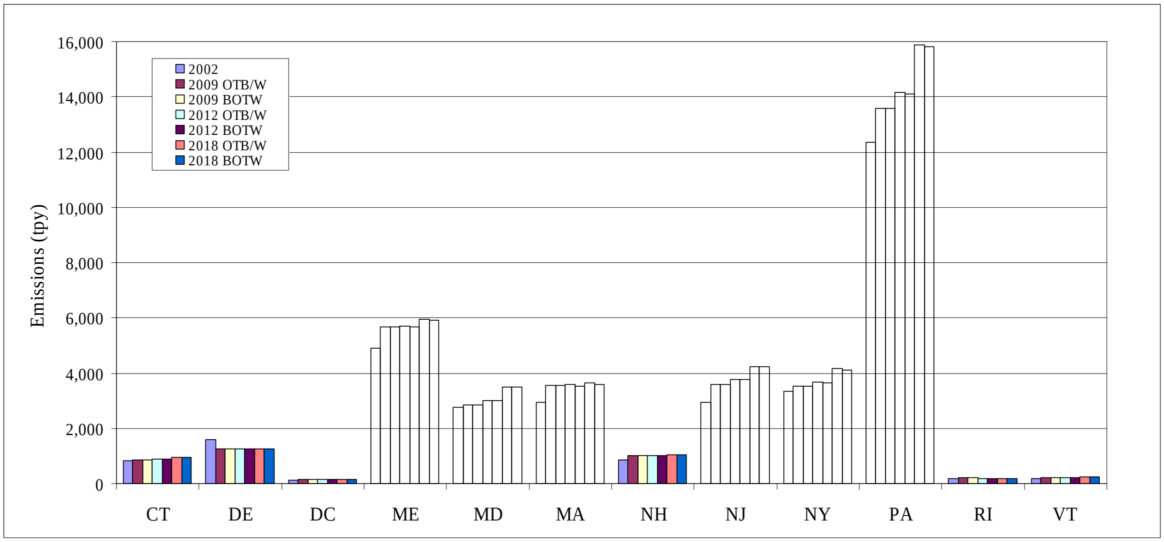


Table 5-11 NonEGU Point Sources
OTB/OTW and BOTW Annual SO2 Emission Projections
(tons per year)

	2002	**2009 OTB/W**	**2009 BOTW**	**2012 OTB/W**	**2012 BOTW**	**2018 OTB/W**	**2018 BOTW**
CT	2,438	2,528	2,528	2,567	2,567	2,644	2,596
DE	35,706	7,117	7,117	7,401	7,401	7,610	7,610
DC	618	707	707	735	533	780	554
ME	14,412	18,656	18,656	18,492	18,393	18,794	18,692
MD	34,193	34,223	34,223	35,373	35,342	38,921	38,886
MA	14,766	18,185	18,185	18,442	17,305	18,955	17,778
NH	2,436	3,099	3,099	3,098	3,098	3,114	3,099
NJ	9,797	7,141	7,141	7,234	7,196	7,855	7,816
NY	58,227	62,922	62,922	64,484	64,432	67,545	67,491
PA	88,259	90,735	90,735	93,441	93,206	99,924	99,681
RI	2,651	3,163	3,163	3,182	3,018	3,164	3,000
VT	874	1,182	1,182	1,147	1,147	1,127	1,127
Total	**264,377**	**249,658**	**249,658**	**255,596**	**253,638**	**270,433**	**268,330**

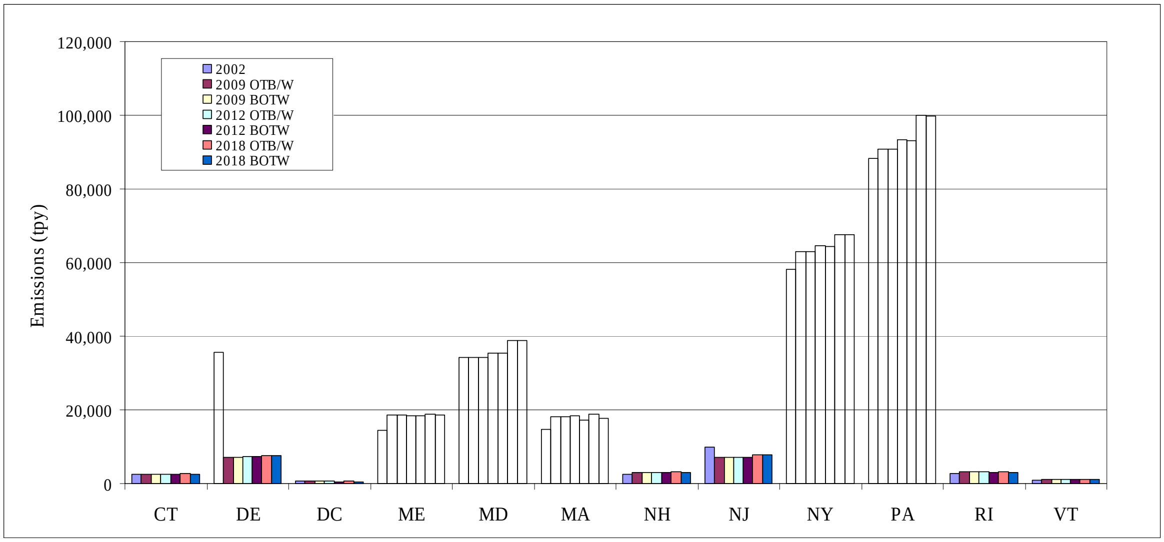
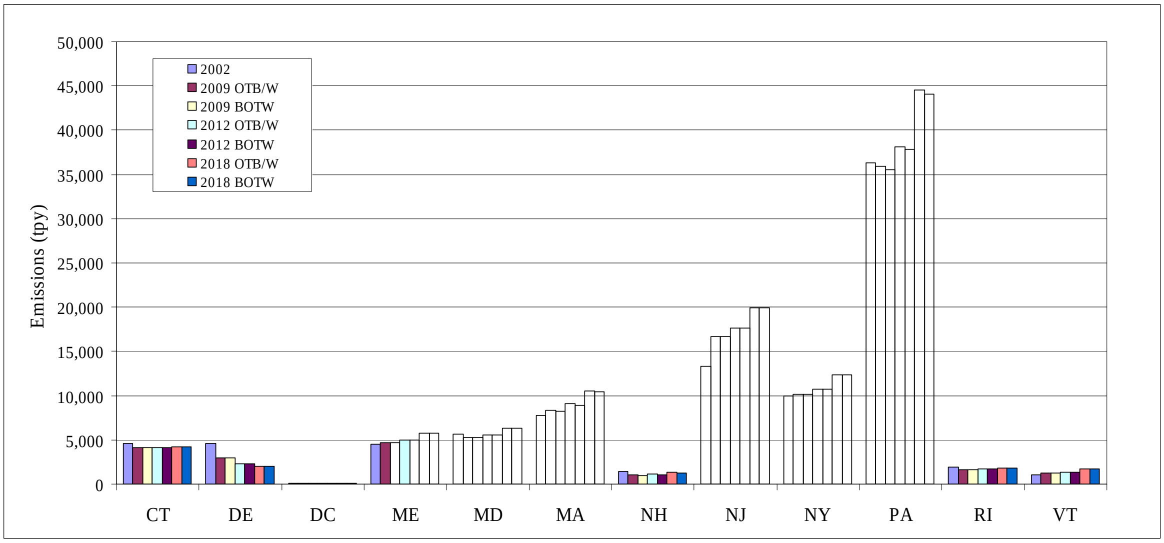


Table 5-12 NonEGU Point Sources
OTB/OTW and BOTW Annual VOC Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	4,604	4,114	4,111	4,152	4,149	4,230	4,227
DE	4,645	2,987	2,981	2,311	2,305	1,993	1,987
DC	69	72	72	75	75	85	85
ME	4,477	4,740	4,740	4,985	4,985	5,709	5,708
MD	5,676	5,297	5,279	5,578	5,559	6,301	6,279
MA	7,794	8,381	8,273	9,061	8,940	10,564	10,418
NH	1,459	1,060	1,005	1,132	1,069	1,294	1,219
NJ	13,318	16,702	16,702	17,621	17,621	19,915	19,915
NY	9,933	10,157	10,141	10,750	10,732	12,354	12,333
PA	36,326	35,875	35,548	38,162	37,795	44,537	44,085
RI	1,898	1,640	1,628	1,695	1,683	1,812	1,799
VT	1,079	1,254	1,238	1,365	1,347	1,730	1,707
Total	**91,278**	**92,279**	**91,718**	**96,887**	**96,260**	**110,524**	**109,762**



5.2 AREA SOURCES

This Section describes the analysis of the OTC and MANE-VU control measures to reduce emissions from area sources. The control measures included in this analysis reduce emissions for the following pollutants and area source categories:

- NOx measures: ICI boilers (natural gas, #2 fuel oil, #4/#6 fuel oil, and coal) and residential and commercial home heating oil;
- Primary PM10 and PM2.5 measures: residential and commercial home heating oil;
- SO2 measures: residential and commercial home heating oil, and ICI boilers (distillate oil).
- VOC measures: adhesives and sealants, emulsified and cutback asphalt paving, consumer products, and portable fuel containers;

For the MANE-VU modeling inventory, each state was asked to complete a matrix identify which control measures to include and in which years the control measure should be applied. Tables 5.13, 5.14, and 5.15 summarize the staff recommendations for control measures to include in the BOTW regional modeling inventory for NOx, SO2, and VOC respectively. The following subsections describe the emission reductions anticipated for each of the area source control measures.

5.2.1 Adhesives and Sealants

The OTC 2006 model rule for adhesives and sealants is based on the reasonably available control technology (RACT) and best available retrofit control technology (BARCT) determination by the California Air Resources Board (CARB) developed in 1998. Adhesive and sealant emission sources are classified as both point sources and area sources. About 96 percent of adhesive and sealant VOC emissions in the OTC states fall into the area source category. The remaining four percent of the VOC emissions are included in the point source inventory.

The emission reduction benefit estimation methodology for area sources is based on information developed and used by CARB for their RACT/BARCT determination in 1998. CARB estimates that the total industrial adhesive and sealant emissions in California to be about 45 tons per day (tpd). Solvent-based adhesive and sealant emissions are estimated to be about 35 tpd of VOC and water-based adhesive and sealant emissions are about 10 tpd of VOC.

Table 5.13 State Staff Recommendations for Control Measures to Include in BOTW Regional Modeling – NOx Area Sources

	ICI Boilers < 25 mmBTU/hour			**ICI Boilers 25-50 mmBtu/hour**			**ICI Boilers 50-100 mmBtu/hour**			**Residential and Commercial Home Heating Oil**		
State	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**
CT	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes
DE	No	No	No	No	No	No	No	No	No	No	No	No
DC	No	No	No	No	No	No	No	No	No	No	Yes	Yes
ME	No	No	No	No	No	No	No	No	No	No	Yes	Yes
MD	No	No	No	No	No	No	No	No	No	No	Yes	Yes
MA	No	No	No	No	No	No	No	No	No	No	Yes	Yes
NH	No	No	No	No	No	No	No	No	No	No	No	Yes
NJ	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
NY	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
PA	No	No	No	No	No	No	No	No	No	No	Yes	Yes
RI	No	No	No	No	No	No	No	No	No	No	Yes	Yes
VT[1]	No	No	No	No	No	No	No	No	No	No	No	No

Yes - Include emission reductions from OTC 2006 control measure in modeling inventory
No - Do not include emission reduction from OTC 2006 control measure in modeling inventory

Table 5.14 State Staff Recommendations for Control Measures to Include in BOTW Regional Modeling – SO2 Area Sources

	ICI Boilers < 25 mmBTU/hour			**ICI Boilers 25-50 mmBtu/hour**			**ICI Boilers 50-100 mmBtu/hour**			**Residential Home Heating Oil**		
State	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**
CT	No	No	No	No	No	No	No	No	No	No	No	Yes
DE	No	No	No	No	No	No	No	No	No	No	No	No
DC	No	No	No	No	No	No	No	No	No	No	Yes	Yes
ME	No	No	No	No	No	No	No	No	No	No	Yes	Yes
MD	No	No	No	No	No	No	No	No	No	No	Yes	Yes
MA	No	No	No	No	No	No	No	No	No	No	Yes	Yes
NH	No	No	No	No	No	No	No	No	No	No	No	Yes
NJ	No	No	No	No	No	No	No	No	No	No	Yes	Yes
NY	No	No	No	No	No	No	No	No	No	No	Yes	Yes
PA	No	No	No	No	No	No	No	No	No	No	Yes	Yes
RI	No	No	No	No	No	No	No	No	No	No	Yes	Yes
VT[1]	No	No	No	No	No	No	No	No	No	No	No	No

Yes - Include emission reductions from OTC 2006 control measure in modeling inventory
No - Do not include emission reduction from OTC 2006 control measure in modeling inventory

Table 5.15 State Staff Recommendations for Control Measures to Include in BOTW Regional Modeling – VOC Area Sources

	Adhesives and Sealants			**Emulsified and Cutback Asphalt Paving**			**Consumer Products**			**Portable Fuel Containers**		
State	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**	**2009**	**2012**	**2018**
CT	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
DE	Yes	Yes	Yes	No[2]	No[2]	No[2]	Yes	Yes	Yes	Yes	Yes	Yes
DC	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
ME	Yes	Yes	Yes	No[3]	No[3]	No[3]	Yes	Yes	Yes	Yes	Yes	Yes
MD	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
MA	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
NH	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
NJ	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
NY	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
PA	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
RI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
VT[1]	No	No	No	No	No	No	No	No	No	No	No	No

Yes - Include emission reductions from OTC 2006 control measure in modeling inventory
No - Do not include emission reduction from OTC 2006 control measure in modeling inventory

1) Vermont indicated that the modeling inventory should not reflect anything beyond the 2002 OTC control level for these source categories in Vermont.
2) Delaware's existing asphalt paving regulations are more stringent than the OTC 2006 control measure.
3) Maine has not yet determined whether to include emission reductions from the OTC 2006 control measure for asphalt paving. Maine's inventory includes emissions only from cutback asphalt; no emissions are reported for emulsified asphalt.

CARB estimated that emission reductions achieved by statewide compliance with the VOC limits in the RACT/BARCT determination will range from approximately 29 to 35 tpd (CARB 1998, pg. 18). These emission reductions correspond to a 64.4 to 77.8 percent reduction from uncontrolled levels. For OTC modeling purposes, we used the lower end of this range (i.e., 64.4 percent reduction) to estimate the emission benefit for area sources due to the OTC 2006 model rule.

5.2.2 Asphalt Paving

The OTC current guideline for asphalt paving calls for a complete ban on the use of cutback asphalt during the ozone season and limits the VOC content of emulsified asphalt to two percent or less. The proposal is still under evaluation. A 20 percent reduction in emissions from emulsified asphalt was assumed for the modeling inventory.

The current regulations in all MANE-VU states generally ban the use of cutback asphalt during the ozone season. In some states, there are a few exemptions from the ban that allow for the use of cutback during the ozone season. It has not yet been determined whether states will modify their cutback asphalt rules to eliminate the exemptions. Since the VOC emissions from the use of cutback asphalt during the ozone season are generally very small, MACTEC assumed that there will be no additional emission reductions from the use of cutback asphalt during the ozone season.

The emission reductions resulting from the two percent VOC content limit on emulsified asphalt depend on the baseline VOC content of emulsified asphalt. The baseline VOC content may range from 0 to 12 percent. New Jersey used a VOC content of 8 percent in their baseline emission calculations (based on the 8 percent limit in their current rule). Reducing the VOC content to 2 percent in New Jersey will result in a 75 percent reduction. Delaware already bans the use of emulsified asphalt that contains any VOC, so there is no reduction in Delaware. Several other states used an average VOC content of 2.5 percent when developing their emission inventory. Thus, reducing the average VOC content from 2.5 percent to 2.0 percent results in a 20 percent reduction in VOC emissions. For States that did not supply a baseline VOC content for asphalt paving, we used the 20 percent reduction in VOC emissions from emulsified asphalt paving during the ozone season.

5.2.3 Consumer Products

The OTC 2006 model rule will modify the OTC 2001 model rule based on amendments adopted by CARB in July 2005. The emission reduction benefit estimation methodology is based on information developed by CARB. CARB estimates 6.05 tons per day of VOC reduced from their July 2005 amendments (CARB 2004, pg. 8), excluding the benefits from the two products (anti-static products and shaving gels) with compliance dates in 2008 or 2009. This equates to about 2,208 tons per year. The population of California as of July 1, 2005 is 36,132,147 (Census 2006). On a per capita basis, the emission reduction from the CARB July 2005 amendments equals 0.122 lbs/capita.

Since the OTC's 2006 control measure is very similar to the CARB July 2005 amendments (with the exclusion of the anti-static products and shaving gel 2008/2009 limits), the per capita emission reductions are expected to be the same in the OTR. The per capita factor after the implementation of the OTC 2001 model rule is 6.06 lbs/capita (Pechan 2001, pg. 8). The percentage reduction from the OTC's 2006 control measure was computed as shown below:

Current OTC Emission Factor = 6.06 lbs/capita
Benefit from CARB 2005 amendments = 0.122 lbs/capita
Percent Reduction = 100%*(1 - (6.06 – 0.122)/6.06)
= 2.0%

The 2.0% reduction will be applied to all states except Vermont, which indicated that they do not want the modeling inventory to reflect anything beyond the 2002 OTC control level for consumer products in Vermont.

5.2.4 Portable Fuel Containers

The OTC 2006 model rule will modify the OTC 2001 model rule based on amendments adopted by CARB in 2006. Estimated emission reductions were based on information compiled by CARB to support their recent amendments. CARB estimated that PFC emissions in 2015 will be 31.9 tpd in California with no additional controls or amendments to the 2000 PFC rules. CARB further estimates that the 2006 amendment will reduce emission from PFCs by 18.4 tpd in 2015 in California compared to the 2000 PFC regulations. Thus, at full implementation, the expected incremental reduction is approximately 58 percent, after an estimated 75 percent reduction from the original 2000 rule (CARB later adjusted the reduction to 65 percent due to unanticipated problems with spillage from the new cans).

The OTC calculations assume that States will adopt the rule by July 2007 and will provide manufacturers one year from the date of the rule to comply. Thus, new compliant PFCs will not be on the market until July 2008. Assuming a 10-year turnover to compliant cans, only 10 percent of the existing inventory of PFCs will comply with the new requirements in the summer of 2009. Therefore, only 10 percent of the full emission benefit estimated by CARB will occur by 2009 – the incremental reduction will be about 5.8 percent in

2009. In 2012, there will be a 40 percent turnover to compliant cans, resulting in an incremental reductions of about 23.2 percent. By 2018, the will be 100 percent penetration to compliant PFCs, resulting in an incremental reduction of 58 percent in 2018.

The emission reductions from the 2006 OTC PFC model rule were calculated only for the emissions accounted for in the area source inventory. Additional benefits (not estimated for this report) would be expected from equipment refueling vapor displacement and spillage that is accounted for in the nonroad inventory.

5.2.5 Industrial/Commercial/Institutional Boilers

In Resolution 06-02, the OTC Commissioners recommended that OTC member states pursue as necessary and appropriate state-specific rulemakings or other implementation methods to establish emission reduction percentages, emission rates or technologies for ICI boilers based on guidelines that varied by boiler size and fuel type. Specifically, the following guidelines were provided:

	NOx Reduction from 2009 Base Emissions by Fuel Type			
Boiler Size (mmBtu/hour)	**Natural Gas**	**#2 Fuel Oil**	**#4/#6 Fuel Oil**	**Coal**
< 25	10	10	10	10
25 to 50	50	50	50	50*
50 to 100	10	10	10	10*
100 to 250	75	40	40	40*
>250	**	**	**	**

* Resolution 06-02 did not specify a percent reduction for coal; for modeling purposes, the same percent reduction specified for #4/#6 fuel oil was used for coal

** Resolution 06-02 specified the reduction for > 250mmBtu/hour boilers to be the "same as EGUs of similar size." The OTC Commissioners have not yet recommended an emission rate or percent reduction for EGUs. As a result, no reductions for ICI boilers > 250 mmBtu/hour were included in the BOTW inventory.

Since the above guidelines vary by boiler size and fuel type, the specific percent reduction applied to an area source category depends on the SCC and design capacity of the source. The SCC identifies the fuel type (for example, SCC 21-02-004-xxx describes distillate oil-fired industrial boilers, SCC 21-02-006-xxx describes natural gas-fired industrial boilers). The area source inventory does not contain any information on the sizes of the units included in the inventories. To apportion area source emissions to the boiler size ranges listed above, MACTEC used data from the *Characterization of the U.S. Industrial/Commercial Boiler Population* (May 2005, Oak Ridge National Laboratory). We used the national estimates of boiler capacity by size from Table ES-1 of the Oak

Ridge report to calculate the percentage of total boiler capacity in each size range. Since the Oak Ridge report distinguished between industrial boilers and commercial/institutional boilers, we developed separate profiles for industrial boilers and for commercial/institutional boilers. We used these boiler size profiles to calculate weighted average percent reductions industrial boilers by fuel type and commercial/institutional boilers by fuel type.

5.2.6 Residential and Commercial Heating Oil

The BOTW control measure for heating oil is based on NESCAUM's report entitled "Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs and Implementation Issues." NESCAUM estimates that reducing the sulfur content of heating oil from 2,000 ppm to 500 ppm lowers SO2 emissions by 75 percent, PM emissions by 80 percent, NOx emissions by 10 percent. The 500 ppm sulfur heating oil is not expected to available on a widespread basis until 2012 at the earliest. These percent reductions were applied to residential distillate oil category (SCC 21-04-004-xxx) and commercial distillate oil category (SCC 21-03-004-xxx). These percent reductions were applied based on the state's recommendations in the matrix which identifies control measures to include and in which years the control measure should be accounted for in the modeling inventory.

5.2.7 BOTW Area Source NIF, SMOKE, and Summary Files

The Version 3 file names and descriptions delivered to MARAMA are shown in Table 5-16.

Table E-1 shows the anticipated percent reductions by SCC and year for the nonEGU point source BOTW control measures.

5.2.8 BOTW Area Source Emission Summaries

Emission summaries by state, year, and pollutant are presented in Tables 5-17 through 5-23 for CO, NH3, NOx, PM10-PRI, PM25-PRI, SO2, and VOC, respectively.

Table 5-16 BOTW Area Source NIF, IDA, and Summary File Names

File Name	Date	Description
MANEVU_BOTW2009_Area_NIFV3_2.mdb	Nov. 9, 2006	Version 3.2 of 2009 BOTW area source NIF inventory
MANEVU_BOTW2012_Area_NIFV3_2.mdb	Nov. 9, 2006	Version 3.2 of 2012 BOTW area source NIF inventory
MANEVU_BOTW2018_Area_NIFV3_2.mdb	Nov. 9, 2006	Version 3.2 of 2018 BOTW area source NIF inventory
MANEVU_BOTW2009_Area_IDAV3_2.txt	Nov. 20, 2006	Version 3.2 of 2009 BOTW area source inventory in SMOKE IDA format
MANEVU_BOTW2012_Area_IDAV3_2.txt	Nov. 20, 2006	Version 3.2 of 2012 BOTW area source inventory in SMOKE IDA format
MANEVU_BOTW2018_Area_IDA3V_2.txt	Nov. 20, 2006	Version 3.2 of 2018 BOTW area source inventory in SMOKE IDA format
MANEVU OTB BOTW Area V3_2 State Summary.xls	Nov. 8, 2006	Spreadsheet with state totals by pollutant for all area sources
MANEVU OTB BOTW Area V3_2 State SCC Summary.xls	Nov. 8, 2006	Spreadsheet with SCC totals by state and pollutant for all area sources.

Table 5-17 Area Sources OTB/OTW and BOTW Annual CO Emission Projections (tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	70,198	65,865	65,865	63,874	63,874	59,797	59,797
DE	14,052	15,395	15,395	15,233	15,233	14,864	14,864
DC	2,300	2,417	2,417	2,460	2,460	2,512	2,512
ME	109,223	102,743	102,743	99,877	99,877	94,181	94,181
MD	141,178	143,653	143,653	144,233	144,233	144,649	144,649
MA	137,496	132,797	132,797	130,255	130,255	125,205	125,205
NH	79,647	76,504	76,504	75,319	75,319	73,038	73,038
NJ	97,657	90,432	90,432	88,048	88,048	83,119	83,119
NY	356,254	336,576	336,576	327,118	327,118	307,659	307,659
PA	266,935	266,887	266,887	264,012	264,012	257,396	257,396
RI	8,007	8,007	8,007	8,026	8,026	8,024	8,024
VT	43,849	42,683	42,683	42,172	42,172	41,283	41,283
Total	**1,326,796**	**1,283,959**	**1,283,959**	**1,260,627**	**1,260,627**	**1,211,727**	**1,211,727**

No BOTW controls were considered for CO.

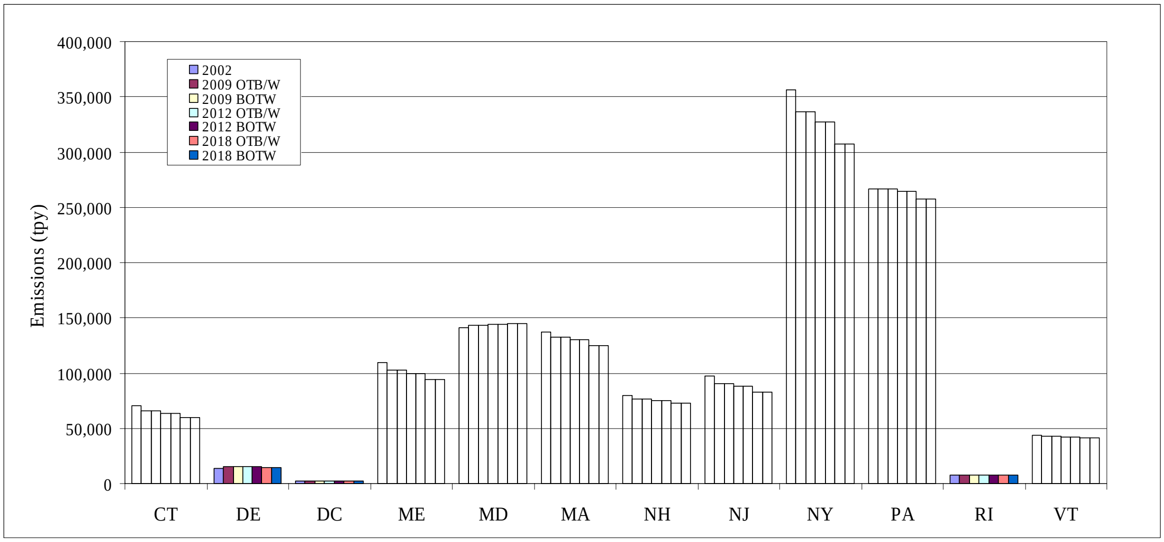


Table 5-18 Area Sources
OTB/OTW and BOTW Annual NH3 Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	5,318	5,208	5,208	5,156	5,156	5,061	5,061
DE	13,279	13,316	13,316	13,328	13,328	13,342	13,342
DC	14	16	16	16	16	17	17
ME	8,747	10,453	10,453	11,116	11,116	12,312	12,312
MD	25,834	31,879	31,879	34,222	34,222	38,155	38,155
MA	18,809	19,131	19,131	19,275	19,275	19,552	19,552
NH	2,158	2,466	2,466	2,584	2,584	2,789	2,789
NJ	17,572	19,457	19,457	20,154	20,154	21,435	21,435
NY	67,422	81,626	81,626	87,116	87,116	96,078	96,078
PA	79,911	98,281	98,281	105,418	105,418	117,400	117,400
RI	883	945	945	972	972	1,025	1,025
VT	9,848	12,156	12,156	13,062	13,062	14,580	14,580
Total	**249,795**	**294,934**	**294,934**	**312,419**	**312,419**	**341,746**	**341,746**

No BOTW controls were considered for NH3.

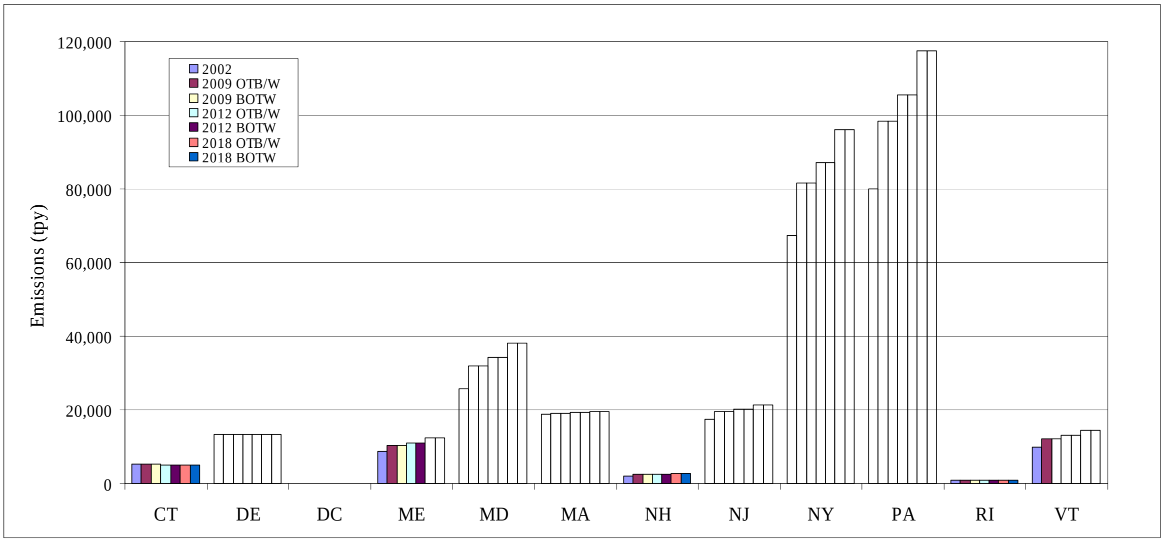


Table 5-19 Area Sources
OTB/OTW and BOTW Annual NOx Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	12,689	13,173	12,245	13,342	12,389	13,388	11,795
DE	2,608	2,821	2,821	2,913	2,913	3,014	3,014
DC	1,644	1,961	1,961	2,081	2,052	2,259	2,229
ME	7,360	7,477	7,477	7,486	7,095	7,424	7,036
MD	15,678	16,858	16,858	17,315	17,007	18,073	17,746
MA	34,281	35,732	35,732	36,331	35,321	37,187	36,199
NH	10,960	11,879	11,879	12,055	12,055	12,430	12,180
NJ	26,692	24,032	24,032	23,981	21,976	23,660	21,684
NY	98,803	106,375	95,190	107,673	92,935	108,444	93,639
PA	47,591	50,162	50,162	50,793	49,773	50,829	49,829
RI	3,886	4,149	4,149	4,260	4,112	4,397	4,249
VT	3,208	3,419	3,419	3,429	3,429	3,430	3,430
Total	**265,400**	**278,038**	**265,925**	**281,659**	**261,057**	**284,535**	**263,030**

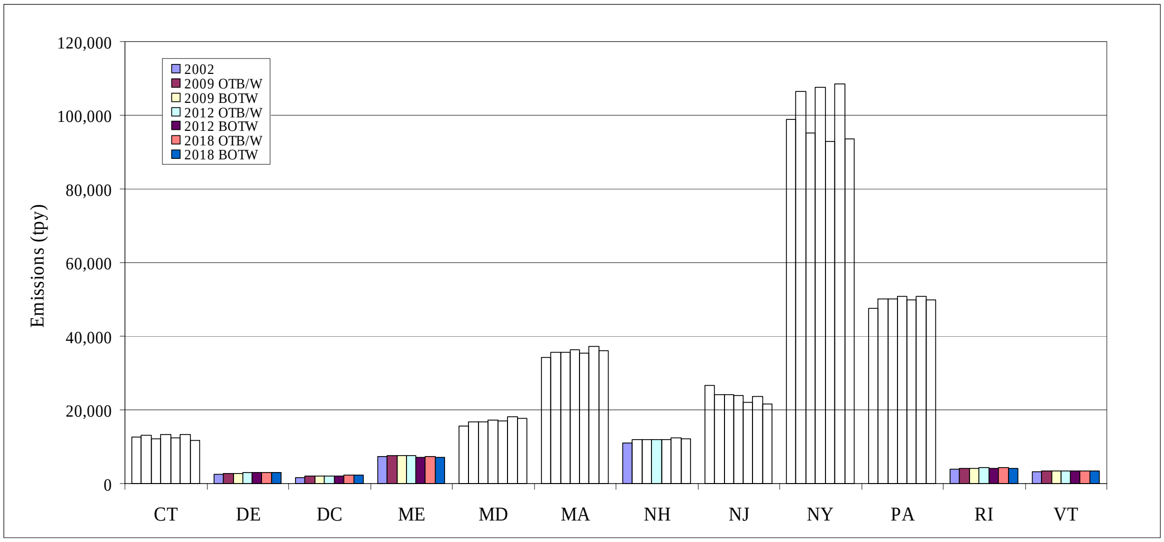


Table 5-20 Area Sources
OTB/OTW and BOTW Annual PM10-PRI Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	48,281	48,970	48,970	49,004	49,004	49,479	48,734
DE	13,039	13,928	13,928	14,236	14,236	14,844	14,844
DC	3,269	3,511	3,511	3,605	3,547	3,825	3,762
ME	168,953	175,979	175,979	179,689	179,004	189,619	188,928
MD	95,060	105,944	105,944	110,141	109,829	117,396	117,066
MA	192,860	198,668	198,668	200,692	200,215	204,922	204,456
NH	43,328	46,060	46,060	47,187	47,187	49,801	49,544
NJ	61,601	61,684	61,684	61,284	60,916	60,880	60,519
NY	369,595	382,124	382,124	385,925	383,234	392,027	389,385
PA	391,897	421,235	421,235	432,844	431,787	454,970	453,934
RI	8,295	8,962	8,962	9,244	8,976	9,797	9,514
VT	56,131	60,521	60,521	62,465	62,465	66,916	66,916
Total	**1,452,309**	**1,527,586**	**1,527,586**	**1,556,316**	**1,550,400**	**1,614,476**	**1,607,602**

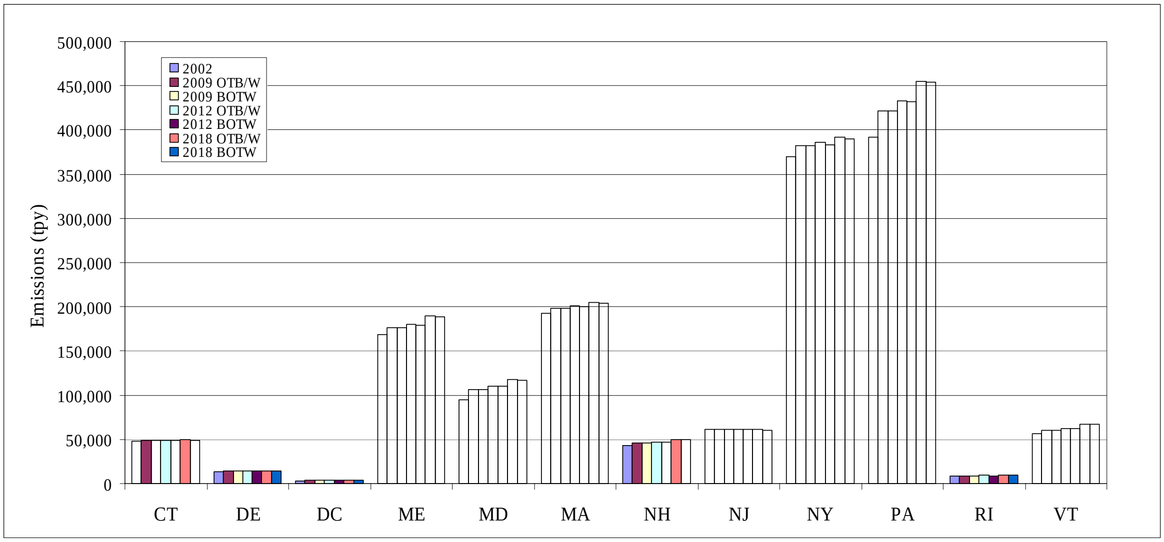


Table 5-21 Area Sources
OTB/OTW and BOTW Annual PM25-PRI Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	14,247	13,766	13,766	13,517	13,517	13,033	12,366
DE	3,204	3,387	3,387	3,403	3,403	3,426	3,426
DC	805	860	860	879	827	917	860
ME	32,774	33,026	33,026	33,189	32,576	33,820	33,201
MD	27,318	28,923	28,923	29,508	29,228	30,449	30,153
MA	42,083	43,121	43,121	43,186	42,820	43,438	43,080
NH	17,532	17,965	17,965	18,050	18,050	18,316	18,087
NJ	19,350	18,590	18,590	18,271	17,924	17,653	17,313
NY	87,154	87,576	87,576	87,260	85,011	86,422	84,211
PA	74,925	79,169	79,169	80,728	79,775	83,570	82,637
RI	2,064	2,184	2,184	2,232	1,996	2,316	2,068
VT	11,065	11,482	11,482	11,652	11,652	12,059	12,059
Total	**332,521**	**340,049**	**340,049**	**341,875**	**336,779**	**345,419**	**339,461**

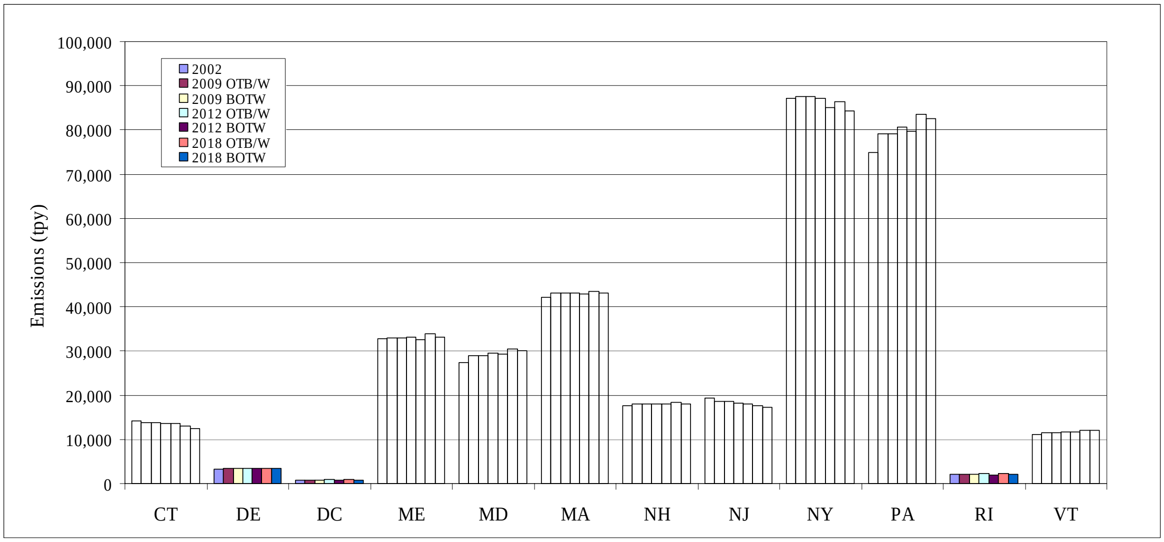


Table 5-22 Area Sources
OTB/OTW and BOTW Annual SO2 Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	12,418	12,581	12,581	12,604	12,604	12,184	3,398
DE	1,588	1,599	1,599	1,602	1,602	1,545	1,545
DC	1,337	1,487	1,487	1,541	499	1,632	522
ME	13,149	13,776	13,776	13,846	4,897	13,901	4,940
MD	12,393	13,685	13,685	14,074	8,762	14,741	9,118
MA	25,488	25,961	25,961	26,029	8,414	25,570	8,357
NH	7,072	7,463	7,463	7,470	7,470	7,421	3,118
NJ	10,744	10,672	10,672	10,697	4,435	10,510	4,374
NY	130,409	139,589	139,589	140,154	98,160	141,408	100,452
PA	63,679	67,535	67,535	67,446	49,212	66,363	48,475
RI	4,557	5,024	5,024	5,189	1,316	5,398	1,368
VT	4,087	4,646	4,646	4,687	4,687	4,764	4,764
Total	**286,921**	**304,018**	**304,018**	**305,339**	**202,058**	**305,437**	**190,431**

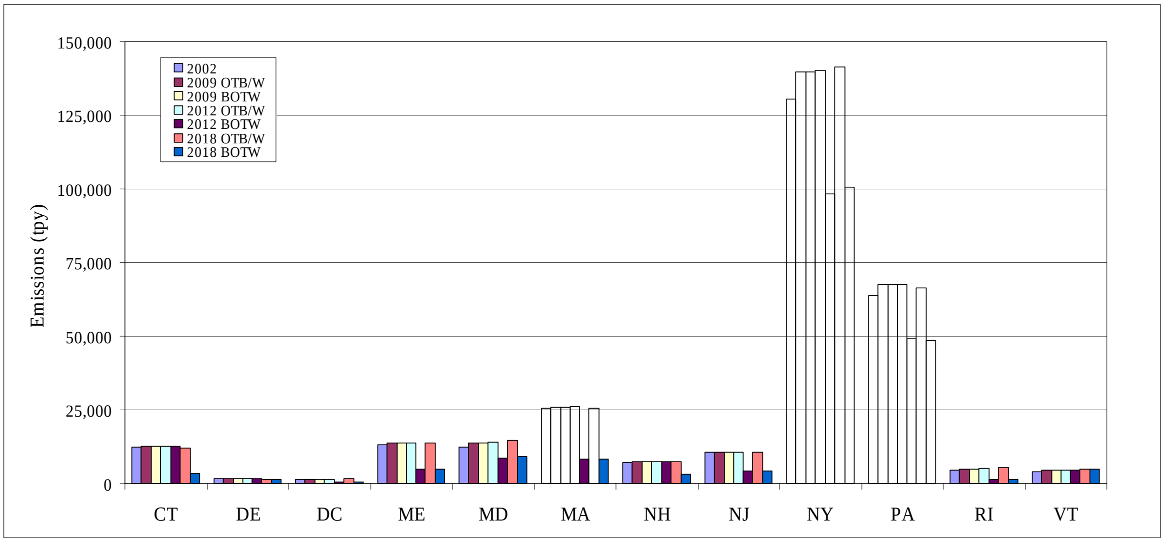
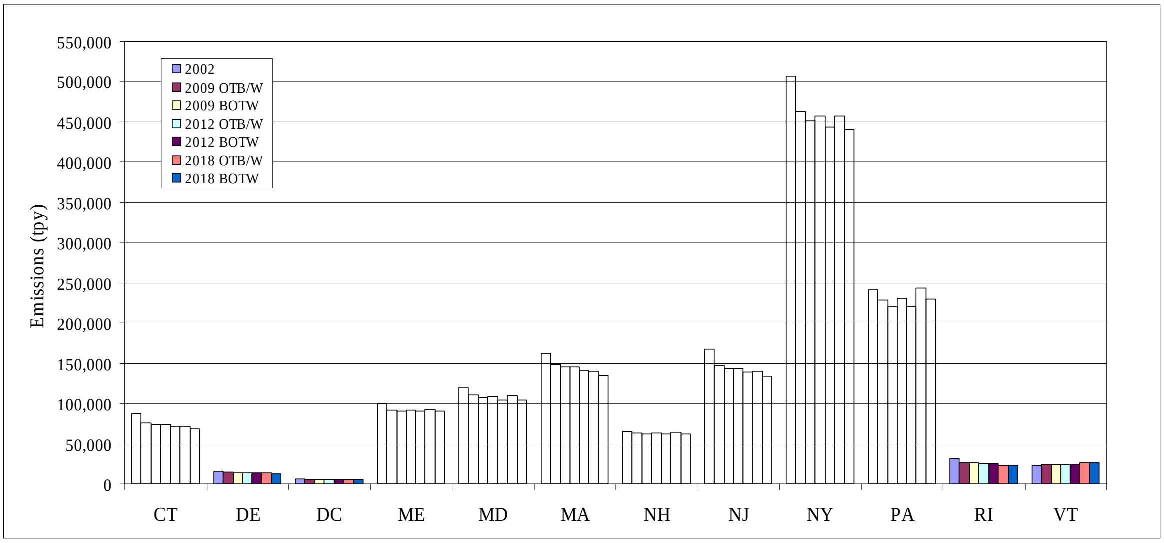


Table 5-23 Area Sources
OTB/OTW and BOTW Annual VOC Emission Projections
(tons per year)

	2002	2009 OTB/W	2009 BOTW	2012 OTB/W	2012 BOTW	2018 OTB/W	2018 BOTW
CT	87,302	75,693	73,738	73,560	71,249	71,274	68,395
DE	15,519	14,245	13,794	13,943	13,408	13,744	13,066
DC	6,432	5,420	5,300	5,352	5,144	5,255	4,991
ME	100,621	91,910	90,869	91,667	90,457	92,410	90,866
MD	120,254	110,385	107,527	108,067	104,400	110,046	104,615
MA	162,145	148,625	145,059	145,674	140,848	140,558	134,963
NH	65,370	63,069	61,860	63,356	61,913	64,368	62,649
NJ	167,882	147,617	143,089	143,752	138,646	139,626	134,089
NY	507,292	462,811	451,669	456,856	443,940	457,421	440,892
PA	240,785	228,444	219,733	230,393	219,897	243,421	230,011
RI	31,402	26,695	26,572	25,548	25,315	23,561	23,305
VT	23,265	24,068	24,068	24,635	24,634	26,198	26,197
Total	**1,528,269**	**1,398,982**	**1,363,278**	**1,382,803**	**1,339,851**	**1,387,882**	**1,334,039**



5.3 Nonroad Mobile Sources

In the June 2007 MOU, the OTC Commissioners recommended that states pursue state-specific rulemakings for one nonroad source categories – portable fuel containers. The OTC 2006 control measure for portable fuel containers will result in addition VOC emission reduction from the refueling of nonroad equipment. However, these reductions could not be estimated due to resource and time constraints.

5.4 Electric Generating Units

In the June 2008 Statement on EGUs, the OTC Commissioners directed OTC staff to complete an evaluation and recommendations for a program beyond CAIR that includes strategies to address the base, intermediate and peak load emissions. No specific emission reduction targets were identified. States specified that no additional reductions from EGUs be included in the BOTW inventory.

5.5 Onroad Mobile Sources

In Resolution 06-02, the OTC Commissioners recommended that the OTC member states pursue a region fuel program consistent with the Energy Act of 2005. No specific emission reduction targets were identified. States specified that no additional reductions from onroad mobile sources be included in the BOTW inventory.

In the June 2007 MOU, the OTC Commissioners recommended that states pursue state-specific rulemakings to implement a mandatory diesel engine chip reflash program. It is our understanding that the emission reductions from the diesel engine chip reflash program are already accounted for in MANE-VU's OTB emission inventory.

Appendix A – NonEGU Point Source Growth Factors

Table A-1 Connecticut Growth Factors by SIC Code

SIC	GF_02_09	GF_02_12	GF_02_18	CTDOL_CAT
0181	1.0019	1.0027	1.0042	Agricultural, Crop Production
1422	0.9400	0.9143	0.8629	Mining
1429	0.9400	0.9143	0.8629	Mining
2051	0.9355	0.9079	0.8526	Manufacturing, Food
2096	0.9355	0.9079	0.8526	Manufacturing, Food
2261	0.9254	0.8934	0.8295	Manufacturing, Textile Product Mills
2262	0.9254	0.8934	0.8295	Manufacturing, Textile Product Mills
2284	0.9254	0.8934	0.8295	Manufacturing, Textile Product Mills
2298	0.9254	0.8934	0.8295	Manufacturing, Textile Product Mills
2434	1.0679	1.0969	1.1551	Manufacturing, Wood Products
2522	1.0435	1.0621	1.0994	Manufacturing, Furniture & Related
2541	1.0679	1.0969	1.1551	Manufacturing, Wood Products
2621	0.8706	0.8152	0.7043	Manufacturing, Paper
2631	0.8706	0.8152	0.7043	Manufacturing, Paper
2652	0.8706	0.8152	0.7043	Manufacturing, Paper
2653	0.8706	0.8152	0.7043	Manufacturing, Paper
2672	0.8706	0.8152	0.7043	Manufacturing, Paper
2673	0.8706	0.8152	0.7043	Manufacturing, Paper
2711	0.8386	0.7695	0.6312	Manufacturing, Printing & Related Activ
2752	0.8386	0.7695	0.6312	Manufacturing, Printing & Related Activ
2754	0.8386	0.7695	0.6312	Manufacturing, Printing & Related Activ
2759	0.8386	0.7695	0.6312	Manufacturing, Printing & Related Activ
2821	1.1024	1.1464	1.2342	Manufacturing, Chemical
2833	1.1024	1.1464	1.2342	Manufacturing, Chemical
2869	1.1024	1.1464	1.2342	Manufacturing, Chemical
2875	1.1024	1.1464	1.2342	Manufacturing, Chemical
3052	0.9591	0.9416	0.9066	Manufacturing, Plastic & Rubber Product
3069	0.9591	0.9416	0.9066	Manufacturing, Plastic & Rubber Product
3081	0.9591	0.9416	0.9066	Manufacturing, Plastic & Rubber Product
3086	0.9591	0.9416	0.9066	Manufacturing, Plastic & Rubber Product
3087	0.9591	0.9416	0.9066	Manufacturing, Plastic & Rubber Product
3272	0.9841	0.9772	0.9636	Manufacturing, Miscellaneous
3312	0.8713	0.8162	0.7059	Manufacturing, Primary Metal
3351	0.8713	0.8162	0.7059	Manufacturing, Primary Metal
3357	0.8713	0.8162	0.7059	Manufacturing, Primary Metal
3423	0.9150	0.8786	0.8057	Manufacturing, Fabricated Metal
3429	0.9150	0.8786	0.8057	Manufacturing, Fabricated Metal
3444	0.9150	0.8786	0.8057	Manufacturing, Fabricated Metal
3469	0.9150	0.8786	0.8057	Manufacturing, Fabricated Metal
3471	0.9150	0.8786	0.8057	Manufacturing, Fabricated Metal
3479	0.9150	0.8786	0.8057	Manufacturing, Fabricated Metal
3497	0.9150	0.8786	0.8057	Manufacturing, Fabricated Metal
3562	0.8778	0.8254	0.7206	Manufacturing, Machinery

SIC	GF_02_09	GF_02_12	GF_02_18	CTDOL_CAT
3569	0.8778	0.8254	0.7206	Manufacturing, Machinery
3579	0.8452	0.7788	0.6461	Manufacturing, Computer & Electronic Eq
3634	0.9149	0.8784	0.8054	Manufacturing, Electrical Equipment, Ap
3675	0.9149	0.8784	0.8054	Manufacturing, Electrical Equipment, Ap
3714	0.9705	0.9578	0.9326	Manufacturing, Transportation Equipment
3721	0.9705	0.9578	0.9326	Manufacturing, Transportation Equipment
3724	0.9705	0.9578	0.9326	Manufacturing, Transportation Equipment
3728	0.9705	0.9578	0.9326	Manufacturing, Transportation Equipment
3731	0.9705	0.9578	0.9326	Manufacturing, Transportation Equipment
3827	0.9841	0.9772	0.9636	Manufacturing, Miscellaneous
3949	0.9841	0.9772	0.9636	Manufacturing, Miscellaneous
3951	0.9841	0.9772	0.9636	Manufacturing, Miscellaneous
4226	1.0921	1.1316	1.2106	Transportation & Warehousing, Warehousi
4911	0.9550	0.9358	0.8972	Utilities
4922	0.9550	0.9358	0.8972	Utilities
4924	0.9550	0.9358	0.8972	Utilities
4931	1.1439	1.2056	1.3290	Waste Management & Remediation Services
4952	1.1439	1.2056	1.3290	Waste Management & Remediation Services
4953	1.1439	1.2056	1.3290	Waste Management & Remediation Services
4961	0.9550	0.9358	0.8972	Utilities
5171	1.0605	1.0864	1.1382	Wholesale Trade, Nondurable Goods
6036	1.0569	1.0814	1.1302	Finance & Insurance
6512	1.0197	1.0282	1.0451	Real Estate & Rental & Leasing
6513	1.0197	1.0282	1.0451	Real Estate & Rental & Leasing
7389	1.0569	1.0814	1.1302	Finance & Insurance
8051	1.0824	1.1177	1.1883	Health Care & Social Assistance, Nursin
8062	1.0583	1.0833	1.1334	Health Care & Social Assistance, Hospit
8063	1.0583	1.0833	1.1334	Health Care & Social Assistance, Hospit
8211	1.0642	1.0918	1.1468	Educational Services
8221	1.0642	1.0918	1.1468	Educational Services
8631	1.0642	1.0918	1.1468	Educational Services
8734	1.1189	1.1699	1.2718	Professional, Scientific, and Technical
9223	1.0185	1.0264	1.0423	Government
9511	1.0185	1.0264	1.0423	Government
9621	1.0185	1.0264	1.0423	Government
9711	1.0185	1.0264	1.0423	Government
3900	0.9841	0.9772	0.9636	Manufacturing, Miscellaneous
5093	1.0527	1.0754	1.1206	Wholesale Trade, Durable Goods
4200	0.9871	0.9815	0.9705	Transportation & Warehousing, Truck Tra

Table A-2 Non-EGU Point Source Growth Factors by SCC Code

See Electronic File: MANE-VU_NonEGU_gf_scc.xls

This table contains 12,791 records with NonEGU point source growth factors by county and SCC. The format for the tables is as follows:

Column A – County FIPS code

Column B – Source Classification Code (SCC)

Column C – EGAS_02_09 this is the EGAS 5.0 factor for projecting from 2002 to 2009

Column D – AEO5_02_09 this is the DOE AEO 2005 factor for projecting from 2002 to 2009

Column E – ST_02_09 this is the state-supplied factor for projecting from 2002 to 2009

Column F – GF_02_09 this is the final factor actually used for projecting from 2002 to 2009 (it is the state-supplied factor, if available; if no state-supplied factor, then it is the AEO2005 factor; if no AEO2005 factor, then it is the default EGAS 5.0 factor)

Column G – EGAS_02_12 this is the EGAS 5.0 factor for projecting from 2002 to 2012

Column H – AEO5_02_12 this is the DOE AEO 2005 factor for projecting from 2002 to 2012

Column I – ST_02_12 this is the state-supplied factor for projecting from 2002 to 2012

Column J – GF_02_09 this is the final factor actually used for projecting from 2002 to 2012 (it is the state-supplied factor, if available; if no state-supplied factor, then it is the AEO2005 factor; if no AEO2005 factor, then it is the default EGAS 5.0 factor)

Column K – EGAS_02_18 this is the EGAS 5.0 factor for projecting from 2002 to 2018

Column J – AEO5_02_18 this is the DOE AEO 2005 factor for projecting from 2002 to 2018

Column M– ST_02_18 this is the state-supplied factor for projecting from 2002 to 2018

Column N – GF_02_09 this is the final factor actually used for projecting from 2002 to 2012 (it is the state-supplied factor, if available; if no state-supplied factor, then it is the AEO2005 factor; if no AEO2005 factor, then it is the default EGAS 5.0 factor)

Column O – SCC description

Appendix B – NonEGU Point Source Control Factors

Table B-1 NonEGU Emission Units Affected by the NOx SIP Call Phase I

FIPS	SITE ID	Facility Name	EU ID	Ozone Season Allowance (tpy)	Prorated Annual Emissions (tpy)	Unit Description
09003	1509	PRATT & WHITNEY DIV UTC	P0049	11	26	FT-8 COGENERATION GAS TURBINE
09011	0604	PFIZER INC	P0001	33	79	BLR B&W FM140-97 #8
09011	0604	PFIZER INC	R0012	31	74	BLR CE #5 (101-4)
09011	3102	SPRAGUE PAPERBOARD INC	R0003	75	180	BLR B&W PFI-22-0 #1
24001	001-0011	WESTVACO FINE PAPERS	1	500	1200	001-0011-3-0018
24001	001-0011	WESTVACO FINE PAPERS	2	440	1056	001-0011-3-0019
25009	1190138	GENERAL ELECTRIC AIRCRAFT	03	29	68	BOILER #3-BABCOCK+WILCOX PPL-2897 DUAL FUEL EV99-3
25009	1190138	GENERAL ELECTRIC AIRCRAFT	05	24	58	TURBINE #1-GE G5301 DUAL FUEL BLDG 99-8
25017	1191844	MIT	02	132	317	TURBINE #1-ABB GT10 DUEL FUEL(EXHAUST TO HRSG)
25025	1190507	TRIGEN BOSTON ENERGY	01	47	113	BOILER #1-BABCOCK+WILCOX HSB8477A DUAL FUEL
25025	1190507	TRIGEN BOSTON ENERGY	02	47	113	BOILER #2-BABCOCK+WILCOX JSB8477B DUAL FUEL
25025	1190507	TRIGEN BOSTON ENERGY	03	47	113	BOILER #3-FOSTER+WHEELER SC DUAL FUEL
25025	1190507	TRIGEN BOSTON ENERGY	04	47	113	BOILER #4-BABCOCK+WILCOX HSB8608A DUAL FUEL
36031	5154800008	INTERNATIONAL PAPER TICONDEROG	POWERH	227	545	EMISSION UNIT
36055	8261400205	KODAK PARK DIVISION	U00015	1721	4130	EMISSION UNIT
36091	5412600007	INTERNATIONAL PAPER HUDSON RIV	UBOILR	124	298	EMISSION UNIT
42003	4200300022	SHENANGO INC.	005	13	31	BOILER #9, NATURAL GAS
42017	420170306	EXELON GENERATION CO/FAIRLESS	043	2	5	POWER HOUSE BOILER NO. 3

FIPS	SITE ID	Facility Name	EU ID	Ozone Season Allowance (tpy)	Prorated Annual Emissions (tpy)	Unit Description
42017	420170306	EXELON GENERATION CO/FAIRLESS	044	73	175	POWER HOUSE BOILER NO. 4
42017	420170306	EXELON GENERATION CO/FAIRLESS	045	61	146	POWER HOUSE BOILER NO. 5
42045	420450016	KIMBERLY CLARK PA LLC/CHESTER	034	2	5	
42045	420450220	FPL ENERGY MH50 LP/MARCUS HOOK	031	82	197	COGENERATION UNIT - ABB TYPE B
42047	420470005	WEYERHAEUSER/JOHNSONBURG MILL	040	85	204	BOILER #81
42047	420470005	WEYERHAEUSER/JOHNSONBURG MILL	041	86	206	BOILER #82
42091	420910028	MERCK & CO/WEST POINT	039	101	242	COGEN II GAS TURBINE
42101	4210101551	SUNOCO CHEMICALS (FORMER ALLIE	052	86	206	BL-703: BOILER #3
42131	421310009	PROCTER & GAMBLE PAPER PROD CO	035	203	482	WESTINGHOUSE 251B12
42133	421330016	PH GLATFELTER CO/SPRING GROVE	034	146	350	#4 POWER BOILER

Table B-2 Cement Kilns Affected by the NOx SIP Call Phase I

FIPS	SITE ID	Facility Name	EU ID	Control Factor	Unit Description
24013	013-0012	LEHIGH PORTLAND CEMENT	39	25.00	013-0012-6-0256 013-0012-6-0256
24021	021-0013	ESSROC CEMENT	21	25.00	021-0013-6-0465 021-0013-6-0465
24021	021-0013	ESSROC CEMENT	22	25.00	021-0013-6-0466 021-0013-6-0466
24043	043-0008	INDEPENDENT CEMENT/ST. LAWEREN	24	25.00	043-0008-6-0495 043-0008-6-0495
36001	4012400001	LAFARGE BUILDING MATERIALS INC	041000	25.00	EMISSION UNIT
36039	4192600021	ST LAWRENCE CEMENT CORP-CATSKI	U00K18	25.00	EMISSION UNIT
36113	5520500013	GLENS FALLS LEHIGH CEMENT	0UKILN	25.00	EMISSION UNIT
42011	420110039	LEHIGH CEMENT CO /EVANSVILLE	121	70.00	PORTLAND CEMENT KILN #1
42011	420110039	LEHIGH CEMENT CO /EVANSVILLE	122	70.00	PORTLAND CEMENT KILN #2
42019	420190024	ARMSTRONG CEMENT & SUPPLY	101	16.00	NO.1 KILN
42019	420190024	ARMSTRONG CEMENT & SUPPLY	121	16.00	NO.2 KILN
42073	420730024	CEMEX INC/WAMPUM CEMENT PLT	226	12.50	
42073	420730024	CEMEX INC/WAMPUM CEMENT PLT	227	0.00	
42073	420730024	CEMEX INC/WAMPUM CEMENT PLT	228	12.70	
42073	420730026	ESSROC/BESSEMER	501	8.00	
42073	420730026	ESSROC/BESSEMER	502	8.00	
42077	420770019	LAFARGE CORP/WHITEHALL PLT	101	12.28	K-2 KILN
42077	420770019	LAFARGE CORP/WHITEHALL PLT	114	100.00	K-3 KILN
42095	420950006	HERCULES CEMENT CO LP/STOCKERT	102	6.88	NO. 1 CEMENT KILN
42095	420950006	HERCULES CEMENT CO LP/STOCKERT	122	6.88	NO. 3 CEMENT KILN
42095	420950012	KEYSTONE PORTLAND CEMENT/EAST	101	27.00	CEMENT KILN NO. 1
42095	420950012	KEYSTONE PORTLAND CEMENT/EAST	102	27.00	CEMENT KILN NO. 2
42095	420950045	ESSROC/NAZARETH LOWER CEMENT	142	41.00	
42095	420950045	ESSROC/NAZARETH LOWER CEMENT	143	41.00	
42095	420950127	ESSROC/NAZARETH CEMENT PLT 3	101	41.00	
42095	420950127	ESSROC/NAZARETH CEMENT PLT 3	102	41.00	
42095	420950127	ESSROC/NAZARETH CEMENT PLT 3	103	41.00	
42095	420950127	ESSROC/NAZARETH CEMENT PLT 3	104	41.00	
42133	421330060	LEHIGH CEMENT CO/YORK OPERATION	200	27.00	

Table B-3 Large IC Engines Affected by the NOx SIP Call Phase II

FIPS	SITE ID	Facility Name	EU ID	Control Factor	Unit Description
24027	027-0223	TRANSCONTINENTAL GAS PIPE LINE	1	80.00	027-0223-5-0054 boiler
42005	420050015	DOMINION TRANS INC/SOUTH BEND	101	80.00	ENGINE #1 (2000 BHP)
42005	420050015	DOMINION TRANS INC/SOUTH BEND	102	80.00	ENGINE #2 (2000 BHP)
42005	420050015	DOMINION TRANS INC/SOUTH BEND	103	80.00	ENGINE #3 (2000 BHP)
42005	420050015	DOMINION TRANS INC/SOUTH BEND	104	80.00	ENGINE #4 (2000 BHP)
42005	420050015	DOMINION TRANS INC/SOUTH BEND	105	80.00	ENGINE #5 (2000 BHP)
42005	420050015	DOMINION TRANS INC/SOUTH BEND	106	80.00	ENGINE #6 (2000 BHP)
42029	420290047	TRANSCONTINENTAL GAS/FRAZER ST	741	80.00	#11 I-C GAS COMPRESSOR ENGINE
42029	420290047	TRANSCONTINENTAL GAS/FRAZER ST	742	80.00	#12 I-C GAS COMPRESSOR ENGINE
42029	420290047	TRANSCONTINENTAL GAS/FRAZER ST	743	80.00	#13 I-C GAS COMPRESSOR ENGINE
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	101	90.00	COOPER-BESSEMER ENGINE #1
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	101	90.00	COOPER-BESSEMER ENGINE #1
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	101	90.00	COOPER-BESSEMER ENGINE #1
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	101	90.00	COOPER-BESSEMER ENGINE #1
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	102	90.00	COOPER-BESSEMER ENGINE #2
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	102	90.00	COOPER-BESSEMER ENGINE #2
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	102	90.00	COOPER-BESSEMER ENGINE #2
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	102	90.00	COOPER-BESSEMER ENGINE #2
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	103	90.00	COOPER-BESSEMER ENGINE #3
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	103	90.00	COOPER-BESSEMER ENGINE #3
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	103	90.00	COOPER-BESSEMER ENGINE #3
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	103	90.00	COOPER-BESSEMER ENGINE #3
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	104	90.00	COOPER-BESSEMER ENGINE #4
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	104	90.00	COOPER-BESSEMER ENGINE #4
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	104	90.00	COOPER-BESSEMER ENGINE #4
42063	420630018	PA STATE SYS OF HIGHER ED/INDI	104	90.00	COOPER-BESSEMER ENGINE #4
42105	421050005	TENNESSEE GAS PIPELINE CO/313	P111	80.00	3,000HP KVT-512 ENGINE
42105	421050005	TENNESSEE GAS PIPELINE CO/313	P112	80.00	2,000HP GMVH-10C ENGINE
42133	421330053	TRANSCONTINENTAL GAS/STATION 1	036	80.00	COOPER-BESSEMER ENGINE #4
42133	421330053	TRANSCONTINENTAL GAS/STATION 1	037	80.00	COOPER-BESSEMER ENGINE #5

B-4 NonEGU Control Factors for Post-2002 MACT Categories

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
20100102	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20100202	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20100702	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20100802	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20100902	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200102	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200104	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200202	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200204	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200301	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200501	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200702	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200706	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20200902	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20201001	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20201002	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20201012	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20201014	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20201602	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20201702	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20300101	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
20300301	NOX	17.000	ZZZZ	Reciprocating Internal Combustion Engines
30400101	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400102	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400103	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400104	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400105	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400106	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400107	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400108	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400109	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400110	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400111	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400112	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400113	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400114	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400115	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400116	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400117	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400118	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400120	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400121	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400130	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400131	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400132	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400133	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400150	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400160	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30400199	PM10-PRI	90.000	RRR	Secondary Aluminum Production
30500301	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30500302	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500303	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500304	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500305	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500306	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500307	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500308	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500309	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500310	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500311	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500312	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500313	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500314	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500315	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500316	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500317	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500318	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500319	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500321	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500322	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500330	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500331	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500332	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500333	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500334	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500335	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500340	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500342	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500350	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500351	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500355	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500360	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500361	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500370	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500397	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500398	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30500399	PM10-PRI	45.100	JJJJJ	Brick and Structural Clay
30501601	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501602	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501603	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501604	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501605	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501606	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501607	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501608	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501609	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501610	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501611	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501612	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501613	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501614	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501615	PM10-PRI	28.000	AAAAA	Lime Manufacturing

SCC	**PLLTCODE**	**CE_MACT**	**SUBPART**	**MACT CATEGORY DESCRIPTION**
30501616	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501617	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501618	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501619	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501620	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501621	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501622	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501623	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501624	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501625	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501626	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501627	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501628	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501629	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501630	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501631	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501632	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501633	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501640	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501650	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501660	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30501699	PM10-PRI	28.000	AAAAA	Lime Manufacturing
30400101	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400102	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400103	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400104	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400105	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400106	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400107	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400108	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400109	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400110	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400111	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400112	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400113	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400114	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400115	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400116	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400117	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400118	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400120	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400121	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400130	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400131	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400132	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400133	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400150	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400160	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30400199	PM25-PRI	90.000	RRR	Secondary Aluminum Production
30500301	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500302	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500303	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay

SCC	**PLLTCODE**	**CE_MACT**	**SUBPART**	**MACT CATEGORY DESCRIPTION**
30500304	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500305	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500306	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500307	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500308	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500309	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500310	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500311	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500312	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500313	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500314	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500315	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500316	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500317	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500318	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500319	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500321	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500322	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500330	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500331	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500332	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500333	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500334	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500335	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500340	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500342	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500350	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500351	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500355	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500360	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500361	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500370	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500397	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500398	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30500399	PM25-PRI	45.100	JJJJJ	Brick and Structural Clay
30501601	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501602	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501603	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501604	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501605	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501606	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501607	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501608	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501609	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501610	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501611	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501612	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501613	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501614	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501615	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501616	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501617	PM25-PRI	28.000	AAAAA	Lime Manufacturing

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30501618	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501619	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501620	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501621	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501622	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501623	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501624	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501625	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501626	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501627	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501628	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501629	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501630	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501631	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501632	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501633	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501640	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501650	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501660	PM25-PRI	28.000	AAAAA	Lime Manufacturing
30501699	PM25-PRI	28.000	AAAAA	Lime Manufacturing
20100101	VOC	0.250	YYYY	Stationary Combustion Turbines
20100102	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20100201	VOC	0.250	YYYY	Stationary Combustion Turbines
20100202	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20100702	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20100802	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20100902	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200101	VOC	0.250	YYYY	Stationary Combustion Turbines
20200102	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200103	VOC	0.250	YYYY	Stationary Combustion Turbines
20200104	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200201	VOC	0.250	YYYY	Stationary Combustion Turbines
20200202	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200203	VOC	0.250	YYYY	Stationary Combustion Turbines
20200204	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200209	VOC	0.250	YYYY	Stationary Combustion Turbines
20200301	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200501	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200702	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200706	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20200902	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20201001	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20201002	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20201012	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20201014	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20201602	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20201702	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20300101	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20300102	VOC	0.250	YYYY	Stationary Combustion Turbines
20300109	VOC	0.250	YYYY	Stationary Combustion Turbines
20300202	VOC	0.250	YYYY	Stationary Combustion Turbines
20300203	VOC	0.250	YYYY	Stationary Combustion Turbines

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
20300209	VOC	0.250	YYYY	Stationary Combustion Turbines
20300301	VOC	40.000	ZZZZ	Reciprocating Internal Combustion Engines
20300701	VOC	0.250	YYYY	Stationary Combustion Turbines
30100501	VOC	26.100	YY	Generic MACT (Carbon Black)
30100502	VOC	26.100	YY	Generic MACT (Carbon Black)
30100503	VOC	26.100	YY	Generic MACT (Carbon Black)
30100504	VOC	26.100	YY	Generic MACT (Carbon Black)
30100506	VOC	26.100	YY	Generic MACT (Carbon Black)
30100507	VOC	26.100	YY	Generic MACT (Carbon Black)
30100508	VOC	26.100	YY	Generic MACT (Carbon Black)
30100509	VOC	26.100	YY	Generic MACT (Carbon Black)
30100510	VOC	26.100	YY	Generic MACT (Carbon Black)
30100599	VOC	26.100	YY	Generic MACT (Carbon Black)
30101005	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101012	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101013	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101014	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101015	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101021	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101022	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101023	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101025	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101026	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101027	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101028	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101033	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101034	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101035	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101036	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101037	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101040	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101045	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101046	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101047	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101050	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101051	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101052	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101053	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101054	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101055	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101061	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101062	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101063	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101064	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101073	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101074	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101075	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101076	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101077	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30101080	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101085	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101086	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101087	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101099	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101827	VOC	55.700	OOO	Polymers and Resins III
30101837	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30101880	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101881	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101882	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101883	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101884	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101885	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101890	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101891	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101892	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101893	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101894	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30101899	VOC	67.400	MMMMM	Flexible Polyurethane Foam Fabrication Ope
30103201	VOC	87.400	UUU	Petroleum Refineries
30103202	VOC	87.400	UUU	Petroleum Refineries
30103203	VOC	87.400	UUU	Petroleum Refineries
30103204	VOC	87.400	UUU	Petroleum Refineries
30103205	VOC	87.400	UUU	Petroleum Refineries
30103299	VOC	87.400	UUU	Petroleum Refineries
30103301	VOC	64.820	MMM	Pesticide Active Ingredient
30103311	VOC	64.820	MMM	Pesticide Active Ingredient
30103312	VOC	64.820	MMM	Pesticide Active Ingredient
30103399	VOC	64.820	MMM	Pesticide Active Ingredient
30103901	VOC	44.500	YY	Generic MACT (Cyanide)
30103902	VOC	44.500	YY	Generic MACT (Cyanide)
30103903	VOC	44.500	YY	Generic MACT (Cyanide)
30105001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105101	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105105	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105108	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105110	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105112	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105114	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105116	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105118	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105120	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105122	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105124	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30105130	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30110002	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30110003	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30110004	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30110005	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30110080	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30110099	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30111103	VOC	43.900	QQQQQ	Friction Products Manufacturing

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30111199	VOC	43.900	QQQQQ	Friction Products Manufacturing
30113001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30113003	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30113004	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30113005	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30113006	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30113007	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
30201901	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201902	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201903	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201904	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201905	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201906	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201907	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201908	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201909	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201911	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201912	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201913	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201914	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201915	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201916	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201917	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201918	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201919	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201920	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201921	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201923	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201925	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201926	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201927	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201930	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201931	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201932	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201933	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201935	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201939	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201941	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201942	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201945	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201949	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201950	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201960	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201997	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201998	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30201999	VOC	38.690	GGGG	Solvent Extraction for Vegetable Oil Produ
30203404	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203405	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203406	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203407	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203410	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203415	VOC	12.500	CCCC	Manufacturing Nutritional Yeast

SCC	**PLLTCODE**	**CE_MACT**	**SUBPART**	**MACT CATEGORY DESCRIPTION**
30203420	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203421	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203422	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203423	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203424	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203504	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203505	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203506	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203507	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203510	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203530	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203531	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203532	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203533	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203534	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203535	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203536	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30203540	VOC	12.500	CCCC	Manufacturing Nutritional Yeast
30300303	VOC	50.000	CCCCC	Coke Ovens: Pushing, Quenching, Battery St
30300304	VOC	50.000	CCCCC	Coke Ovens: Pushing, Quenching, Battery St
30400301	VOC	40.000	EEEEE	Iron and Steel Foundries
30400302	VOC	40.000	EEEEE	Iron and Steel Foundries
30400303	VOC	40.000	EEEEE	Iron and Steel Foundries
30400304	VOC	40.000	EEEEE	Iron and Steel Foundries
30400305	VOC	40.000	EEEEE	Iron and Steel Foundries
30400310	VOC	40.000	EEEEE	Iron and Steel Foundries
30400314	VOC	40.000	EEEEE	Iron and Steel Foundries
30400315	VOC	40.000	EEEEE	Iron and Steel Foundries
30400316	VOC	40.000	EEEEE	Iron and Steel Foundries
30400317	VOC	40.000	EEEEE	Iron and Steel Foundries
30400318	VOC	40.000	EEEEE	Iron and Steel Foundries
30400319	VOC	40.000	EEEEE	Iron and Steel Foundries
30400320	VOC	40.000	EEEEE	Iron and Steel Foundries
30400321	VOC	40.000	EEEEE	Iron and Steel Foundries
30400322	VOC	40.000	EEEEE	Iron and Steel Foundries
30400325	VOC	40.000	EEEEE	Iron and Steel Foundries
30400330	VOC	40.000	EEEEE	Iron and Steel Foundries
30400331	VOC	40.000	EEEEE	Iron and Steel Foundries
30400332	VOC	40.000	EEEEE	Iron and Steel Foundries
30400333	VOC	40.000	EEEEE	Iron and Steel Foundries
30400340	VOC	40.000	EEEEE	Iron and Steel Foundries
30400341	VOC	40.000	EEEEE	Iron and Steel Foundries
30400342	VOC	40.000	EEEEE	Iron and Steel Foundries
30400350	VOC	40.000	EEEEE	Iron and Steel Foundries
30400351	VOC	40.000	EEEEE	Iron and Steel Foundries
30400352	VOC	40.000	EEEEE	Iron and Steel Foundries
30400353	VOC	40.000	EEEEE	Iron and Steel Foundries
30400354	VOC	40.000	EEEEE	Iron and Steel Foundries
30400355	VOC	40.000	EEEEE	Iron and Steel Foundries
30400356	VOC	40.000	EEEEE	Iron and Steel Foundries
30400357	VOC	40.000	EEEEE	Iron and Steel Foundries
30400358	VOC	40.000	EEEEE	Iron and Steel Foundries

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30400360	VOC	40.000	EEEEE	Iron and Steel Foundries
30400370	VOC	40.000	EEEEE	Iron and Steel Foundries
30400371	VOC	40.000	EEEEE	Iron and Steel Foundries
30400398	VOC	40.000	EEEEE	Iron and Steel Foundries
30400399	VOC	40.000	EEEEE	Iron and Steel Foundries
30500101	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500102	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500103	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500104	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500105	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500106	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500107	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500108	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500110	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500111	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500112	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500113	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500114	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500115	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500116	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500117	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500118	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500119	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500120	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500121	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500130	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500131	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500132	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500133	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500134	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500135	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500140	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500141	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500142	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500143	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500144	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500145	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500146	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500147	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500150	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500151	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500152	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500153	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500154	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500198	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30500199	VOC	28.000	LLLLL	Asphalt Process and Asphalt Roofing
30501201	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501202	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501203	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501204	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501205	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501206	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30501207	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501208	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501209	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501211	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501212	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501213	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501214	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501215	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501221	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501222	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501223	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501224	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30501299	VOC	74.000	HHHH	Wet Formed Fiberglass Mat Production
30600201	VOC	87.400	UUU	Petroleum Refineries (FCC)
30600202	VOC	87.400	UUU	Petroleum Refineries (FCC)
30600301	VOC	87.400	UUU	Petroleum Refineries (FCC)
30600402	VOC	87.400	UUU	Petroleum Refineries (FCC)
30600901	VOC	65.630	UUU	Petroleum Refineries
30600902	VOC	65.630	UUU	Petroleum Refineries
30600903	VOC	65.630	UUU	Petroleum Refineries
30600904	VOC	65.630	UUU	Petroleum Refineries
30600905	VOC	65.630	UUU	Petroleum Refineries
30600906	VOC	65.630	UUU	Petroleum Refineries
30600999	VOC	65.630	UUU	Petroleum Refineries
30601001	VOC	65.630	UUU	Petroleum Refineries
30601101	VOC	65.630	UUU	Petroleum Refineries
30601201	VOC	65.630	UUU	Petroleum Refineries
30601301	VOC	65.630	UUU	Petroleum Refineries
30601401	VOC	65.630	UUU	Petroleum Refineries
30609901	VOC	65.630	UUU	Petroleum Refineries
30609902	VOC	65.630	UUU	Petroleum Refineries
30609903	VOC	65.630	UUU	Petroleum Refineries
30609904	VOC	65.630	UUU	Petroleum Refineries
30609905	VOC	65.630	UUU	Petroleum Refineries
30610001	VOC	65.630	UUU	Petroleum Refineries
30688801	VOC	87.400	UUU	Petroleum Refineries
30688802	VOC	87.400	UUU	Petroleum Refineries
30688803	VOC	87.400	UUU	Petroleum Refineries
30688804	VOC	87.400	UUU	Petroleum Refineries
30688805	VOC	87.400	UUU	Petroleum Refineries
30700103	VOC	7.020	MM	Comustion Sources at Kraft, Soda, and Sulf
30700104	VOC	7.020	MM	Comustion Sources at Kraft, Soda, and Sulf
30700106	VOC	7.020	MM	Comustion Sources at Kraft, Soda, and Sulf
30700110	VOC	7.020	MM	Comustion Sources at Kraft, Soda, and Sulf
30700602	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700604	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700606	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700607	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700608	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700610	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700611	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700621	VOC	41.200	DDDD	Plywood and Composite Wood Products

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30700625	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700626	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700628	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700629	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700630	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700631	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700632	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700635	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700640	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700651	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700655	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700661	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700701	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700702	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700703	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700704	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700705	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700706	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700707	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700708	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700709	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700710	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700711	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700712	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700713	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700714	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700715	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700716	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700717	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700718	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700720	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700725	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700727	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700730	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700734	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700735	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700736	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700737	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700740	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700744	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700746	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700747	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700750	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700752	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700753	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700756	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700757	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700760	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700762	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700763	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700766	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700767	VOC	41.200	DDDD	Plywood and Composite Wood Products

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30700769	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700770	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700771	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700780	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700781	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700783	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700785	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700788	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700789	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700790	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700791	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700792	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700793	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700798	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700799	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700921	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700923	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700925	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700927	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700931	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700932	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700933	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700934	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700935	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700936	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700937	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700939	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700940	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700950	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700960	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700971	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700980	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700981	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700982	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700983	VOC	41.200	DDDD	Plywood and Composite Wood Products
30700984	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701001	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701008	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701009	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701010	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701015	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701020	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701030	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701040	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701053	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701054	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701055	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701057	VOC	41.200	DDDD	Plywood and Composite Wood Products
30701199	VOC	82.050	JJJJ	Paper and Other Web Coating
30800101	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800102	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800103	VOC	47.600	XXXX	Rubber Tire Manufacturing

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
30800104	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800105	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800106	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800107	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800108	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800109	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800110	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800111	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800112	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800113	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800114	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800115	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800116	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800117	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800120	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800121	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800122	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800123	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800124	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800125	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800126	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800127	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800128	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800129	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800130	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800131	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800132	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800133	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800197	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800198	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800199	VOC	47.600	XXXX	Rubber Tire Manufacturing
30800701	VOC	70.000	WWWW	Reinforced Plastics
30800702	VOC	70.000	WWWW	Reinforced Plastics
30800703	VOC	70.000	WWWW	Reinforced Plastics
30800704	VOC	70.000	WWWW	Reinforced Plastics
30800705	VOC	70.000	WWWW	Reinforced Plastics
30800720	VOC	70.000	WWWW	Reinforced Plastics
30800721	VOC	70.000	WWWW	Reinforced Plastics
30800722	VOC	70.000	WWWW	Reinforced Plastics
30800723	VOC	70.000	WWWW	Reinforced Plastics
30800724	VOC	70.000	WWWW	Reinforced Plastics
30800799	VOC	70.000	WWWW	Reinforced Plastics
30801001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
31401001	VOC	43.900	QQQQQ	Friction Products Manufacturing
31401002	VOC	43.900	QQQQQ	Friction Products Manufacturing
31401501	VOC	35.790	VVVV	Boat Manufacturing
31401503	VOC	35.790	VVVV	Boat Manufacturing
31401504	VOC	35.790	VVVV	Boat Manufacturing
31401510	VOC	35.790	VVVV	Boat Manufacturing
31401511	VOC	35.790	VVVV	Boat Manufacturing
31401512	VOC	35.790	VVVV	Boat Manufacturing
31401513	VOC	35.790	VVVV	Boat Manufacturing

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
31401514	VOC	35.790	VVVV	Boat Manufacturing
31401515	VOC	35.790	VVVV	Boat Manufacturing
31401516	VOC	35.790	VVVV	Boat Manufacturing
31401517	VOC	35.790	VVVV	Boat Manufacturing
31401518	VOC	35.790	VVVV	Boat Manufacturing
31401525	VOC	35.790	VVVV	Boat Manufacturing
31401530	VOC	35.790	VVVV	Boat Manufacturing
31401531	VOC	35.790	VVVV	Boat Manufacturing
31401540	VOC	35.790	VVVV	Boat Manufacturing
31401541	VOC	35.790	VVVV	Boat Manufacturing
31401550	VOC	35.790	VVVV	Boat Manufacturing
31401551	VOC	35.790	VVVV	Boat Manufacturing
31401552	VOC	35.790	VVVV	Boat Manufacturing
31401553	VOC	35.790	VVVV	Boat Manufacturing
31401560	VOC	35.790	VVVV	Boat Manufacturing
31401561	VOC	35.790	VVVV	Boat Manufacturing
31401562	VOC	35.790	VVVV	Boat Manufacturing
31401563	VOC	35.790	VVVV	Boat Manufacturing
31401570	VOC	35.790	VVVV	Boat Manufacturing
31401571	VOC	35.790	VVVV	Boat Manufacturing
31604001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
31604002	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
31604003	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
32099997	VOC	38.900	TTTT	Leather Finishing Operations
32099998	VOC	38.900	TTTT	Leather Finishing Operations
32099999	VOC	38.900	TTTT	Leather Finishing Operations
40201101	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201103	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201104	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201105	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201111	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201112	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201113	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201114	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201115	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201116	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201121	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201122	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201197	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201198	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201199	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201201	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201210	VOC	60.170	OOOO	Fabric Printing, Coating, & Dyeing
40201301	VOC	82.050	JJJJ	Paper and Other Web Coating
40201303	VOC	82.050	JJJJ	Paper and Other Web Coating
40201304	VOC	82.050	JJJJ	Paper and Other Web Coating
40201305	VOC	82.050	JJJJ	Paper and Other Web Coating
40201310	VOC	82.050	JJJJ	Paper and Other Web Coating
40201320	VOC	82.050	JJJJ	Paper and Other Web Coating
40201330	VOC	82.050	JJJJ	Paper and Other Web Coating
40201399	VOC	82.050	JJJJ	Paper and Other Web Coating
40201601	VOC	66.730	IIII	Auto and Light Trucks Surface Coating

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
40201602	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201603	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201604	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201605	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201606	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201607	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201608	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201609	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201619	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201620	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201621	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201622	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201623	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201624	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201625	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201626	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201627	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201628	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201629	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201630	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201631	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201632	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201699	VOC	66.730	IIII	Auto and Light Trucks Surface Coating
40201702	VOC	70.830	KKKK	Metal Can
40201703	VOC	70.830	KKKK	Metal Can
40201704	VOC	70.830	KKKK	Metal Can
40201705	VOC	70.830	KKKK	Metal Can
40201706	VOC	70.830	KKKK	Metal Can
40201721	VOC	70.830	KKKK	Metal Can
40201722	VOC	70.830	KKKK	Metal Can
40201723	VOC	70.830	KKKK	Metal Can
40201724	VOC	70.830	KKKK	Metal Can
40201725	VOC	70.830	KKKK	Metal Can
40201726	VOC	70.830	KKKK	Metal Can
40201727	VOC	70.830	KKKK	Metal Can
40201728	VOC	70.830	KKKK	Metal Can
40201729	VOC	70.830	KKKK	Metal Can
40201731	VOC	70.830	KKKK	Metal Can
40201732	VOC	70.830	KKKK	Metal Can
40201733	VOC	70.830	KKKK	Metal Can
40201734	VOC	70.830	KKKK	Metal Can
40201735	VOC	70.830	KKKK	Metal Can
40201736	VOC	70.830	KKKK	Metal Can
40201737	VOC	70.830	KKKK	Metal Can
40201738	VOC	70.830	KKKK	Metal Can
40201739	VOC	70.830	KKKK	Metal Can
40201799	VOC	70.830	KKKK	Metal Can
40201801	VOC	53.060	SSSS	Metal Coil
40201802	VOC	53.060	SSSS	Metal Coil
40201803	VOC	53.060	SSSS	Metal Coil
40201804	VOC	53.060	SSSS	Metal Coil
40201805	VOC	53.060	SSSS	Metal Coil

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
40201806	VOC	53.060	SSSS	Metal Coil
40201807	VOC	53.060	SSSS	Metal Coil
40201899	VOC	53.060	SSSS	Metal Coil
40202001	VOC	73.070	RRRR	Metal Furniture
40202002	VOC	73.070	RRRR	Metal Furniture
40202003	VOC	73.070	RRRR	Metal Furniture
40202004	VOC	73.070	RRRR	Metal Furniture
40202005	VOC	73.070	RRRR	Metal Furniture
40202010	VOC	73.070	RRRR	Metal Furniture
40202011	VOC	73.070	RRRR	Metal Furniture
40202012	VOC	73.070	RRRR	Metal Furniture
40202013	VOC	73.070	RRRR	Metal Furniture
40202014	VOC	73.070	RRRR	Metal Furniture
40202015	VOC	73.070	RRRR	Metal Furniture
40202020	VOC	73.070	RRRR	Metal Furniture
40202021	VOC	73.070	RRRR	Metal Furniture
40202022	VOC	73.070	RRRR	Metal Furniture
40202023	VOC	73.070	RRRR	Metal Furniture
40202024	VOC	73.070	RRRR	Metal Furniture
40202025	VOC	73.070	RRRR	Metal Furniture
40202031	VOC	73.070	RRRR	Metal Furniture
40202032	VOC	73.070	RRRR	Metal Furniture
40202033	VOC	73.070	RRRR	Metal Furniture
40202034	VOC	73.070	RRRR	Metal Furniture
40202035	VOC	73.070	RRRR	Metal Furniture
40202036	VOC	73.070	RRRR	Metal Furniture
40202037	VOC	73.070	RRRR	Metal Furniture
40202038	VOC	73.070	RRRR	Metal Furniture
40202039	VOC	73.070	RRRR	Metal Furniture
40202099	VOC	73.070	RRRR	Metal Furniture
40202101	VOC	74.000	QQQQ	Wood Building Products
40202103	VOC	74.000	QQQQ	Wood Building Products
40202104	VOC	74.000	QQQQ	Wood Building Products
40202105	VOC	74.000	QQQQ	Wood Building Products
40202106	VOC	74.000	QQQQ	Wood Building Products
40202107	VOC	74.000	QQQQ	Wood Building Products
40202108	VOC	74.000	QQQQ	Wood Building Products
40202109	VOC	74.000	QQQQ	Wood Building Products
40202110	VOC	74.000	QQQQ	Wood Building Products
40202111	VOC	74.000	QQQQ	Wood Building Products
40202117	VOC	74.000	QQQQ	Wood Building Products
40202118	VOC	74.000	QQQQ	Wood Building Products
40202131	VOC	74.000	QQQQ	Wood Building Products
40202132	VOC	74.000	QQQQ	Wood Building Products
40202133	VOC	74.000	QQQQ	Wood Building Products
40202140	VOC	74.000	QQQQ	Wood Building Products
40202199	VOC	74.000	QQQQ	Wood Building Products
40202201	VOC	77.000	PPPP	Plastic Parts Coating
40202202	VOC	77.000	PPPP	Plastic Parts Coating
40202203	VOC	77.000	PPPP	Plastic Parts Coating
40202204	VOC	77.000	PPPP	Plastic Parts Coating
40202205	VOC	77.000	PPPP	Plastic Parts Coating

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
40202206	VOC	77.000	PPPP	Plastic Parts Coating
40202207	VOC	77.000	PPPP	Plastic Parts Coating
40202208	VOC	77.000	PPPP	Plastic Parts Coating
40202209	VOC	77.000	PPPP	Plastic Parts Coating
40202210	VOC	77.000	PPPP	Plastic Parts Coating
40202211	VOC	77.000	PPPP	Plastic Parts Coating
40202212	VOC	77.000	PPPP	Plastic Parts Coating
40202213	VOC	77.000	PPPP	Plastic Parts Coating
40202214	VOC	77.000	PPPP	Plastic Parts Coating
40202215	VOC	77.000	PPPP	Plastic Parts Coating
40202220	VOC	77.000	PPPP	Plastic Parts Coating
40202229	VOC	77.000	PPPP	Plastic Parts Coating
40202230	VOC	77.000	PPPP	Plastic Parts Coating
40202239	VOC	77.000	PPPP	Plastic Parts Coating
40202240	VOC	77.000	PPPP	Plastic Parts Coating
40202249	VOC	77.000	PPPP	Plastic Parts Coating
40202250	VOC	77.000	PPPP	Plastic Parts Coating
40202259	VOC	77.000	PPPP	Plastic Parts Coating
40202270	VOC	77.000	PPPP	Plastic Parts Coating
40202280	VOC	77.000	PPPP	Plastic Parts Coating
40202299	VOC	77.000	PPPP	Plastic Parts Coating
40202501	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202502	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202503	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202504	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202505	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202510	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202511	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202512	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202515	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202520	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202521	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202522	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202523	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202524	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202525	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202531	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202532	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202533	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202534	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202535	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202536	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202537	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202542	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202543	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202544	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202545	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202546	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202599	VOC	47.930	MMMM	Misc. Metal Parts and Products
40202601	VOC	66.200	HHHHH	Misc. Coating Manufacturing
40202602	VOC	66.200	HHHHH	Misc. Coating Manufacturing
40202603	VOC	66.200	HHHHH	Misc. Coating Manufacturing

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
40202604	VOC	66.200	HHHHH	Misc. Coating Manufacturing
40202605	VOC	66.200	HHHHH	Misc. Coating Manufacturing
40202606	VOC	66.200	HHHHH	Misc. Coating Manufacturing
40202607	VOC	66.200	HHHHH	Misc. Coating Manufacturing
40202699	VOC	66.200	HHHHH	Misc. Coating Manufacturing
40388801	VOC	65.630	UUU	Petroleum Refineries
40388802	VOC	65.630	UUU	Petroleum Refineries
40388803	VOC	65.630	UUU	Petroleum Refineries
40388804	VOC	65.630	UUU	Petroleum Refineries
40388805	VOC	65.630	UUU	Petroleum Refineries
40399999	VOC	65.630	UUU	Petroleum Refineries
50400101	VOC	50.080	GGGGG	Site Remediation
50400102	VOC	50.080	GGGGG	Site Remediation
50400103	VOC	50.080	GGGGG	Site Remediation
50400104	VOC	50.080	GGGGG	Site Remediation
50400150	VOC	50.080	GGGGG	Site Remediation
50400151	VOC	50.080	GGGGG	Site Remediation
50400201	VOC	50.080	GGGGG	Site Remediation
50400202	VOC	50.080	GGGGG	Site Remediation
50410001	VOC	50.080	GGGGG	Site Remediation
50410002	VOC	50.080	GGGGG	Site Remediation
50410003	VOC	50.080	GGGGG	Site Remediation
50410004	VOC	50.080	GGGGG	Site Remediation
50410005	VOC	50.080	GGGGG	Site Remediation
50410010	VOC	50.080	GGGGG	Site Remediation
50410020	VOC	50.080	GGGGG	Site Remediation
50410021	VOC	50.080	GGGGG	Site Remediation
50410022	VOC	50.080	GGGGG	Site Remediation
50410030	VOC	50.080	GGGGG	Site Remediation
50410040	VOC	50.080	GGGGG	Site Remediation
50410101	VOC	50.080	GGGGG	Site Remediation
50410110	VOC	50.080	GGGGG	Site Remediation
50410111	VOC	50.080	GGGGG	Site Remediation
50410112	VOC	50.080	GGGGG	Site Remediation
50410120	VOC	50.080	GGGGG	Site Remediation
50410121	VOC	50.080	GGGGG	Site Remediation
50410122	VOC	50.080	GGGGG	Site Remediation
50410123	VOC	50.080	GGGGG	Site Remediation
50410124	VOC	50.080	GGGGG	Site Remediation
50410210	VOC	50.080	GGGGG	Site Remediation
50410211	VOC	50.080	GGGGG	Site Remediation
50410212	VOC	50.080	GGGGG	Site Remediation
50410213	VOC	50.080	GGGGG	Site Remediation
50410214	VOC	50.080	GGGGG	Site Remediation
50410215	VOC	50.080	GGGGG	Site Remediation
50410216	VOC	50.080	GGGGG	Site Remediation
50410310	VOC	50.080	GGGGG	Site Remediation
50410311	VOC	50.080	GGGGG	Site Remediation
50410312	VOC	50.080	GGGGG	Site Remediation
50410313	VOC	50.080	GGGGG	Site Remediation
50410314	VOC	50.080	GGGGG	Site Remediation
50410321	VOC	50.080	GGGGG	Site Remediation

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
50410322	VOC	50.080	GGGGG	Site Remediation
50410405	VOC	50.080	GGGGG	Site Remediation
50410406	VOC	50.080	GGGGG	Site Remediation
50410407	VOC	50.080	GGGGG	Site Remediation
50410408	VOC	50.080	GGGGG	Site Remediation
50410409	VOC	50.080	GGGGG	Site Remediation
50410420	VOC	50.080	GGGGG	Site Remediation
50410510	VOC	50.080	GGGGG	Site Remediation
50410511	VOC	50.080	GGGGG	Site Remediation
50410512	VOC	50.080	GGGGG	Site Remediation
50410513	VOC	50.080	GGGGG	Site Remediation
50410514	VOC	50.080	GGGGG	Site Remediation
50410520	VOC	50.080	GGGGG	Site Remediation
50410521	VOC	50.080	GGGGG	Site Remediation
50410522	VOC	50.080	GGGGG	Site Remediation
50410523	VOC	50.080	GGGGG	Site Remediation
50410524	VOC	50.080	GGGGG	Site Remediation
50410525	VOC	50.080	GGGGG	Site Remediation
50410530	VOC	50.080	GGGGG	Site Remediation
50410531	VOC	50.080	GGGGG	Site Remediation
50410532	VOC	50.080	GGGGG	Site Remediation
50410533	VOC	50.080	GGGGG	Site Remediation
50410534	VOC	50.080	GGGGG	Site Remediation
50410535	VOC	50.080	GGGGG	Site Remediation
50410536	VOC	50.080	GGGGG	Site Remediation
50410537	VOC	50.080	GGGGG	Site Remediation
50410538	VOC	50.080	GGGGG	Site Remediation
50410539	VOC	50.080	GGGGG	Site Remediation
50410540	VOC	50.080	GGGGG	Site Remediation
50410541	VOC	50.080	GGGGG	Site Remediation
50410542	VOC	50.080	GGGGG	Site Remediation
50410543	VOC	50.080	GGGGG	Site Remediation
50410560	VOC	50.080	GGGGG	Site Remediation
50410561	VOC	50.080	GGGGG	Site Remediation
50410562	VOC	50.080	GGGGG	Site Remediation
50410563	VOC	50.080	GGGGG	Site Remediation
50410564	VOC	50.080	GGGGG	Site Remediation
50410565	VOC	50.080	GGGGG	Site Remediation
50410610	VOC	50.080	GGGGG	Site Remediation
50410620	VOC	50.080	GGGGG	Site Remediation
50410621	VOC	50.080	GGGGG	Site Remediation
50410622	VOC	50.080	GGGGG	Site Remediation
50410623	VOC	50.080	GGGGG	Site Remediation
50410640	VOC	50.080	GGGGG	Site Remediation
50410641	VOC	50.080	GGGGG	Site Remediation
50410642	VOC	50.080	GGGGG	Site Remediation
50410643	VOC	50.080	GGGGG	Site Remediation
50410644	VOC	50.080	GGGGG	Site Remediation
50410645	VOC	50.080	GGGGG	Site Remediation
50410710	VOC	50.080	GGGGG	Site Remediation
50410711	VOC	50.080	GGGGG	Site Remediation
50410712	VOC	50.080	GGGGG	Site Remediation

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
50410720	VOC	50.080	GGGGG	Site Remediation
50410721	VOC	50.080	GGGGG	Site Remediation
50410722	VOC	50.080	GGGGG	Site Remediation
50410723	VOC	50.080	GGGGG	Site Remediation
50410724	VOC	50.080	GGGGG	Site Remediation
50410725	VOC	50.080	GGGGG	Site Remediation
50410726	VOC	50.080	GGGGG	Site Remediation
50410740	VOC	50.080	GGGGG	Site Remediation
50410760	VOC	50.080	GGGGG	Site Remediation
50410761	VOC	50.080	GGGGG	Site Remediation
50410762	VOC	50.080	GGGGG	Site Remediation
50410763	VOC	50.080	GGGGG	Site Remediation
50410764	VOC	50.080	GGGGG	Site Remediation
50410765	VOC	50.080	GGGGG	Site Remediation
50410766	VOC	50.080	GGGGG	Site Remediation
50410780	VOC	50.080	GGGGG	Site Remediation
50480001	VOC	50.080	GGGGG	Site Remediation
50482001	VOC	50.080	GGGGG	Site Remediation
50482002	VOC	50.080	GGGGG	Site Remediation
50482599	VOC	50.080	GGGGG	Site Remediation
50490004	VOC	50.080	GGGGG	Site Remediation
62540001	VOC	62.900	UUUU	Cellulose Products
62540010	VOC	62.900	UUUU	Cellulose Products
62540020	VOC	62.900	UUUU	Cellulose Products
62540021	VOC	62.900	UUUU	Cellulose Products
62540022	VOC	62.900	UUUU	Cellulose Products
62540023	VOC	62.900	UUUU	Cellulose Products
62540024	VOC	62.900	UUUU	Cellulose Products
62540025	VOC	62.900	UUUU	Cellulose Products
62540030	VOC	62.900	UUUU	Cellulose Products
62540040	VOC	62.900	UUUU	Cellulose Products
62540041	VOC	62.900	UUUU	Cellulose Products
62540042	VOC	62.900	UUUU	Cellulose Products
62540050	VOC	62.900	UUUU	Cellulose Products
62580001	VOC	62.900	UUUU	Cellulose Products
62582001	VOC	62.900	UUUU	Cellulose Products
62582002	VOC	62.900	UUUU	Cellulose Products
62582501	VOC	62.900	UUUU	Cellulose Products
62582502	VOC	62.900	UUUU	Cellulose Products
62582503	VOC	62.900	UUUU	Cellulose Products
62582599	VOC	62.900	UUUU	Cellulose Products
64130001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130025	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130101	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130110	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130111	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130112	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130125	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130201	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130210	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
64130211	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64130225	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64131001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64131010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64131011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64131015	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64131020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64131025	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64131030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64132001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64132010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64132011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64132020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64132025	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64132030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64133001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64133010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64133011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64133020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64133025	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64133030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64180001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64182001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64182002	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64182599	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64420001	VOC	62.900	UUUU	Cellulose Products
64420010	VOC	62.900	UUUU	Cellulose Products
64420011	VOC	62.900	UUUU	Cellulose Products
64420012	VOC	62.900	UUUU	Cellulose Products
64420013	VOC	62.900	UUUU	Cellulose Products
64420014	VOC	62.900	UUUU	Cellulose Products
64420015	VOC	62.900	UUUU	Cellulose Products
64420016	VOC	62.900	UUUU	Cellulose Products
64420020	VOC	62.900	UUUU	Cellulose Products
64420021	VOC	62.900	UUUU	Cellulose Products
64420022	VOC	62.900	UUUU	Cellulose Products
64420030	VOC	62.900	UUUU	Cellulose Products
64420031	VOC	62.900	UUUU	Cellulose Products
64420032	VOC	62.900	UUUU	Cellulose Products
64420033	VOC	62.900	UUUU	Cellulose Products
64420034	VOC	62.900	UUUU	Cellulose Products
64420040	VOC	62.900	UUUU	Cellulose Products
64420041	VOC	62.900	UUUU	Cellulose Products
64420042	VOC	62.900	UUUU	Cellulose Products
64430001	VOC	62.900	UUUU	Cellulose Products
64430010	VOC	62.900	UUUU	Cellulose Products
64430011	VOC	62.900	UUUU	Cellulose Products
64430012	VOC	62.900	UUUU	Cellulose Products
64430013	VOC	62.900	UUUU	Cellulose Products
64430014	VOC	62.900	UUUU	Cellulose Products
64430015	VOC	62.900	UUUU	Cellulose Products
64430016	VOC	62.900	UUUU	Cellulose Products

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
64430017	VOC	62.900	UUUU	Cellulose Products
64430030	VOC	62.900	UUUU	Cellulose Products
64431001	VOC	62.900	UUUU	Cellulose Products
64431010	VOC	62.900	UUUU	Cellulose Products
64431011	VOC	62.900	UUUU	Cellulose Products
64431012	VOC	62.900	UUUU	Cellulose Products
64431013	VOC	62.900	UUUU	Cellulose Products
64431014	VOC	62.900	UUUU	Cellulose Products
64431015	VOC	62.900	UUUU	Cellulose Products
64431016	VOC	62.900	UUUU	Cellulose Products
64431017	VOC	62.900	UUUU	Cellulose Products
64431030	VOC	62.900	UUUU	Cellulose Products
64450001	VOC	62.900	UUUU	Cellulose Products
64450010	VOC	62.900	UUUU	Cellulose Products
64450011	VOC	62.900	UUUU	Cellulose Products
64450012	VOC	62.900	UUUU	Cellulose Products
64450013	VOC	62.900	UUUU	Cellulose Products
64450014	VOC	62.900	UUUU	Cellulose Products
64450020	VOC	62.900	UUUU	Cellulose Products
64450021	VOC	62.900	UUUU	Cellulose Products
64450022	VOC	62.900	UUUU	Cellulose Products
64450030	VOC	62.900	UUUU	Cellulose Products
64450031	VOC	62.900	UUUU	Cellulose Products
64450032	VOC	62.900	UUUU	Cellulose Products
64450033	VOC	62.900	UUUU	Cellulose Products
64450034	VOC	62.900	UUUU	Cellulose Products
64450035	VOC	62.900	UUUU	Cellulose Products
64450036	VOC	62.900	UUUU	Cellulose Products
64450040	VOC	62.900	UUUU	Cellulose Products
64450041	VOC	62.900	UUUU	Cellulose Products
64450042	VOC	62.900	UUUU	Cellulose Products
64450050	VOC	62.900	UUUU	Cellulose Products
64450051	VOC	62.900	UUUU	Cellulose Products
64450052	VOC	62.900	UUUU	Cellulose Products
64450053	VOC	62.900	UUUU	Cellulose Products
64450060	VOC	62.900	UUUU	Cellulose Products
64450061	VOC	62.900	UUUU	Cellulose Products
64450062	VOC	62.900	UUUU	Cellulose Products
64520001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520021	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520022	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520023	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520031	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520032	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520040	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64520041	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64521001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64521010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
64521011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64521020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64521021	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64521022	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64521023	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64521040	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64521041	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610012	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610021	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610022	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610031	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610032	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610040	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610041	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610050	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610101	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610110	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610111	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610112	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610120	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610121	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610122	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610130	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610131	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610132	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610140	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610141	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610142	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610143	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610150	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610201	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610210	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610211	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610212	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610220	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610221	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610222	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610230	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610231	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610232	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610240	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610241	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610242	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610250	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610301	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610310	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610311	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
64610312	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610320	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610321	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610322	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610330	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610331	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610332	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610340	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64610350	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615012	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615021	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615022	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615023	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64615030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620012	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620013	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620015	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620016	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620017	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620018	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620021	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620022	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620025	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620026	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620027	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620031	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620032	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620033	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620034	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620035	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620036	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620037	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64620038	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630012	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630015	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630016	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630025	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630026	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630035	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630040	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
64630041	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630042	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630050	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630051	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630052	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630053	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630080	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630081	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630082	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64630083	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631012	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631015	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631016	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631025	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631026	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631040	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631050	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631051	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631052	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631053	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631080	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631081	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631082	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64631083	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632015	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632016	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632040	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632041	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632042	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632050	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632051	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632052	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632053	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632080	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632081	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632082	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64632083	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64680001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64682001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64682002	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64682501	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64682502	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64682599	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc

SCC	**PLLTCODE**	**CE_MACT**	**SUBPART**	**MACT CATEGORY DESCRIPTION**
64820010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64821001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64821010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64822001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64822010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64823001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64823010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64824001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64824010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64880001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64882001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64882002	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64882599	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
64920001	VOC	62.900	UUUU	Cellulose Products
64920010	VOC	62.900	UUUU	Cellulose Products
64920011	VOC	62.900	UUUU	Cellulose Products
64920012	VOC	62.900	UUUU	Cellulose Products
64920013	VOC	62.900	UUUU	Cellulose Products
64920020	VOC	62.900	UUUU	Cellulose Products
64920021	VOC	62.900	UUUU	Cellulose Products
64920022	VOC	62.900	UUUU	Cellulose Products
64920030	VOC	62.900	UUUU	Cellulose Products
64920031	VOC	62.900	UUUU	Cellulose Products
64920032	VOC	62.900	UUUU	Cellulose Products
64920033	VOC	62.900	UUUU	Cellulose Products
64920034	VOC	62.900	UUUU	Cellulose Products
64930001	VOC	62.900	UUUU	Cellulose Products
64930010	VOC	62.900	UUUU	Cellulose Products
64930011	VOC	62.900	UUUU	Cellulose Products
64930012	VOC	62.900	UUUU	Cellulose Products
64930020	VOC	62.900	UUUU	Cellulose Products
64930021	VOC	62.900	UUUU	Cellulose Products
64930030	VOC	62.900	UUUU	Cellulose Products
64930031	VOC	62.900	UUUU	Cellulose Products
64930035	VOC	62.900	UUUU	Cellulose Products
64930040	VOC	62.900	UUUU	Cellulose Products
64930041	VOC	62.900	UUUU	Cellulose Products
64930045	VOC	62.900	UUUU	Cellulose Products
64930050	VOC	62.900	UUUU	Cellulose Products
64931001	VOC	62.900	UUUU	Cellulose Products
64931010	VOC	62.900	UUUU	Cellulose Products
64931011	VOC	62.900	UUUU	Cellulose Products
64931012	VOC	62.900	UUUU	Cellulose Products
64931020	VOC	62.900	UUUU	Cellulose Products
64931021	VOC	62.900	UUUU	Cellulose Products
64931022	VOC	62.900	UUUU	Cellulose Products
64931030	VOC	62.900	UUUU	Cellulose Products
64931031	VOC	62.900	UUUU	Cellulose Products
64931032	VOC	62.900	UUUU	Cellulose Products
64931040	VOC	62.900	UUUU	Cellulose Products
64931041	VOC	62.900	UUUU	Cellulose Products
64931050	VOC	62.900	UUUU	Cellulose Products

SCC	PLLTCODE	CE_MACT	SUBPART	MACT CATEGORY DESCRIPTION
64980001	VOC	62.900	UUUU	Cellulose Products
64982001	VOC	62.900	UUUU	Cellulose Products
64982002	VOC	62.900	UUUU	Cellulose Products
64982599	VOC	62.900	UUUU	Cellulose Products
65135001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
65140001	VOC	44.500	YY	Generic MACT (Cyanide)
65140010	VOC	44.500	YY	Generic MACT (Cyanide)
65140011	VOC	44.500	YY	Generic MACT (Cyanide)
65140012	VOC	44.500	YY	Generic MACT (Cyanide)
65140013	VOC	44.500	YY	Generic MACT (Cyanide)
65140014	VOC	44.500	YY	Generic MACT (Cyanide)
65140015	VOC	44.500	YY	Generic MACT (Cyanide)
65140016	VOC	44.500	YY	Generic MACT (Cyanide)
65140017	VOC	44.500	YY	Generic MACT (Cyanide)
65140018	VOC	44.500	YY	Generic MACT (Cyanide)
65140030	VOC	44.500	YY	Generic MACT (Cyanide)
68430001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68430010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68430011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68430020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68430030	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68430031	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68430032	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68445001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68445010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68445013	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68445020	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68445022	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68445101	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68445201	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68510001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68510010	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68510011	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68580001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68582001	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68582002	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc
68582599	VOC	66.200	FFFF	Misc. Organic Chemical Production and Proc

Table B-5 NonEGU Source Shutdowns

FIPS	SITE ID	FACILTY NAME	EU ID	UNIT DESCRIPTION
10003	1000300021	SUNCO INC R M	001	BOILER #1
10003	1000300021	SUNCO INC R M	002	BOILER #2
10003	1000300021	SUNCO INC R M	003	BOILER #3
10003	1000300016	MOTIVA ENTERPRISES LLC	072	METHANOL PLT HTR 41-H-1
10003	1000300004	WILMINGTON PIECE DYE CO	ALL	ALL
10003	1000300032	GENERAL CHEMICAL CORPORATION	ALL	ALL
10003	1000300074	METACHEM PRODUCTS LLC	ALL	ALL
10003	1000300127	VPI FILM LLC	ALL	ALL
10003	1000300129	LAFARGE NORTH AMERICA INC	ALL	ALL
10003	1000300350	KANEKA DELAWARE CORPORATION	ALL	ALL
25001	1200202	PARTYLITE WORLDWIDE	ALL	ALL
25001	1200614	BOURNE LANDFILL	ALL	ALL
25003	1170002	ADVANCED INFORMATION	ALL	ALL
25003	1170005	CATAMOUNT PELLET FUE	ALL	ALL
25003	1170048	SPRAGUE NORTH ADAMS	ALL	ALL
25003	1170056	BERKSHIRE GAS STOCKB	ALL	ALL
25003	1170078	MACDERMID GRAPHIC AR	ALL	ALL
25003	1170091	LANE CONSTRUCTION CO	ALL	ALL
25005	1200009	TEXAS INSTRUMENTS	ALL	ALL
25005	1200031	CONDEA VISTA CO	ALL	ALL
25005	1200036	ELKAY REVERE CORP	ALL	ALL
25005	1200037	AEROVOX INCORPORATED	ALL	ALL
25005	1200065	ROSEMAR SILVER COMPA	ALL	ALL
25005	1200080	ATTLEBORO REFINING C	ALL	ALL
25005	1200116	STEDRO TEXTILES	ALL	ALL
25005	1200138	CLIFTEX CORPORATION	ALL	ALL
25005	1200169	PAUL DEVER STATE SCH	ALL	ALL
25005	1200209	PHARMACY SERVICE COR	ALL	ALL
25005	1200216	BRISTOL COUNTY JAIL	ALL	ALL
25005	1200235	SEA WATCH INTERNATIO	ALL	ALL
25005	1200393	OLSONS GREENHOUSES	ALL	ALL
25005	1200468	AA WILL MATERIALS-FR	ALL	ALL
25005	1200498	CRAPO HILL LANDFILL	ALL	ALL
25005	1200510	KREW INCORPORATED	ALL	ALL
25005	1200513	AEROVOX INCORPORATED	ALL	ALL
25005	1200542	LALLY COLUMN CORP	ALL	ALL
25005	1200673	HOMELAND BUILDERS	ALL	ALL
25005	1200824	JUSTIN CLOTHING CO	ALL	ALL
25005	1200880	VELVET DRIVE TRANSMI	ALL	ALL

FIPS	SITE ID	FACILTY NAME	EU ID	UNIT DESCRIPTION
25005	1192308	INTERSTATE MAT & RUB	ALL	ALL
25009	1210057	COASTAL METAL FINISH	ALL	ALL
25009	1210058	AMESBURY CHAIR	ALL	ALL
25009	1210075	HAMPSHIRE FABRICS	ALL	ALL
25009	1210099	WASTE MANAGEMENT HUN	ALL	ALL
25009	1210110	CUSTOM INDUSTRIES IN	ALL	ALL
25009	1210114	SAGAMORE INDUSTRIAL	ALL	ALL
25009	1210143	LABELS INC	ALL	ALL
25009	1210154	NEWARK ATLANTIC PAPE	ALL	ALL
25009	1210208	TEK COATING COMPANY	ALL	ALL
25009	1210209	NATIONAL NORTHEAST	ALL	ALL
25009	1210223	STARENSIER INC	ALL	ALL
25009	1210400	SANMINA CORPORATION	ALL	ALL
25009	1210401	COVANTA HAVERHILL IN	ALL	ALL
25009	1210404	TEKE FURNITURE RESTO	ALL	ALL
25009	1190756	PERMAIR LEATHERS INC	ALL	ALL
25009	1190842	SLB SNACKS INC	ALL	ALL
25009	1190983	SALEM OIL & GREASE C	ALL	ALL
25009	1191036	JCR ELECTRONICS	ALL	ALL
25009	1195900	LEPAGES INC	ALL	ALL
25013	0420008	DELUXE FINANCIAL	ALL	ALL
25013	0420010	FRYE COPYSYSTEMS INC	ALL	ALL
25013	0420013	JAHN FOUNDRY CORPORA	ALL	ALL
25013	0420052	APW/WRIGHT LINE	ALL	ALL
25013	0420130	KODAK POLYCHROME GRA	ALL	ALL
25013	0420175	FIBERMARK DSI	ALL	ALL
25013	0420218	SPRINGFIELD PRINTING	ALL	ALL
25013	0420252	KODAK POLYCHROME GRA	ALL	ALL
25013	0420528	NATIONAL METAL INDUS	ALL	ALL
25015	0420060	BERKSHIRE GAS HATFIE	ALL	ALL
25015	0420105	INDUSTRIAL POWER SER	ALL	ALL
25015	0420170	TECHALLOY COMPANY IN	ALL	ALL
25015	0420424	MAGNAT MACHINETECH I	ALL	ALL
25015	0420463	INDUSTRIAL PROP OF E	ALL	ALL
25015	0420540	GENERAL CABLE CORP	ALL	ALL
25015	0420614	REXAM IMAGE PRODUCTS	ALL	ALL
25017	1210013	MERRIMACK MAGNETICS	ALL	ALL
25017	1210050	MAJILITE MFG INC	ALL	ALL
25017	1210064	FINISH UNLIMITED INC	ALL	ALL
25017	1190080	MASS BROKEN STONE CO	ALL	ALL
25017	1210127	USM CORPORATION	ALL	ALL

FIPS	SITE ID	FACILTY NAME	EU ID	UNIT DESCRIPTION
25017	1210147	UMASS LOWELL-RESIDEN	ALL	ALL
25017	1210182	JOAN FABRICS CORP	ALL	ALL
25017	1190203	SC WAKEFIELD 200	ALL	ALL
25017	1190212	OLYMPUS SPECIALTY HO	ALL	ALL
25017	1190258	ROYAL INSTITUTIONAL	ALL	ALL
25017	1210334	T&T INDUSTRIAL	ALL	ALL
25017	1190465	PRINTED CIRCUIT CORP	ALL	ALL
25017	1190611	GEORGE MEADE FOUNDRY	ALL	ALL
25017	1190734	NEW ENGLAND CONFECTI	ALL	ALL
25017	1180794	SCHOTT CML FIBEROPTI	ALL	ALL
25017	1190984	SUNGARD AVAILABILITY	ALL	ALL
25017	1191008	RAYTHEON SYSTEMS CO	ALL	ALL
25017	1191217	BOSTON SCIENTIFIC CO	ALL	ALL
25017	1191267	AGFA DIVISION OF BAY	ALL	ALL
25017	1191351	MIT EDUCATIONAL FACI	ALL	ALL
25017	1191389	LONGVIEW FIBRE COMPA	ALL	ALL
25017	1191534	SWISSTRONICS INCORPO	ALL	ALL
25017	1191653	FOCAL INCORPORATED	ALL	ALL
25017	1191668	LEE PRODUCTS COMPANY	ALL	ALL
25017	1191735	TYCO ELECTRONICS COR	ALL	ALL
25017	1191897	GENZYME CORPORATION	ALL	ALL
25017	1194001	WF WOOD INC	ALL	ALL
25017	1194010	RR DONNELLEY & SONS	ALL	ALL
25017	1214012	PERFORMANCE CORRUGAT	ALL	ALL
25021	1190246	SOUTHWOOD COMMUNITY	ALL	ALL
25021	1190313	INNOVATIVE MEMBRANE	ALL	ALL
25021	1180359	BEVILACQUA PAVING CO	ALL	ALL
25021	1200515	FOXBOROUGH REALTY AS	ALL	ALL
25021	1200616	PLAINVILLE GENERATIN	ALL	ALL
25021	1190670	RAYTHEON ELECTRONIC	ALL	ALL
25021	1190714	TEVA PHARMACEUTICAL	ALL	ALL
25021	1190962	NIDEC AMERICA CORPOR	ALL	ALL
25021	1191562	BARCLAY HOUSE THE	ALL	ALL
25021	1191726	MWRA QUINCY PS	ALL	ALL
25021	1192130	CURRY WOODWORKING IN	ALL	ALL
25021	1199000	MEDFIELD STATE HOSPI	ALL	ALL
25023	1200637	FRANKLIN FIXTURES IN	ALL	ALL
25023	1200698	CRANBERRY GRAPHICS I	ALL	ALL
25023	1192101	GTR FINISHING CORPOR	ALL	ALL
25023	1192109	ALGER CORPORATION TH	ALL	ALL
25023	1192210	IMPERIA CORPORATION	ALL	ALL

FIPS	SITE ID	FACILTY NAME	EU ID	UNIT DESCRIPTION
25023	1199994	TEST-RADIUS-FITZGERA	ALL	ALL
25025	1190035	BOSTON WATER & SEWER	ALL	ALL
25025	1190057	NEPONSET RIVER VALLE	ALL	ALL
25025	1190101	UNIFIRST CORP	ALL	ALL
25025	1190357	DAMRELL EWER PARTNER	ALL	ALL
25025	1190478	WINTHROP COMMUNITY H	ALL	ALL
25025	1190649	ZAPCO READVILLE COGE	ALL	ALL
25025	1190808	PUBLIC HEALTH COMMUN	ALL	ALL
25025	1191551	BEACON CAPITAL PARTN	ALL	ALL
25025	1191566	NEW ENGLAND TRAWLER	ALL	ALL
25025	1191621	FEDERAL MOGUL FRICTI	ALL	ALL
25025	1191662	EQUITY OFFICE	ALL	ALL
25025	1191956	CHANNEL CENTER:PARCE	ALL	ALL
25025	1195596	SYNTHON IND INCORPOR	ALL	ALL
25027	1180010	CANTERBURY TOWERS	ALL	ALL
25027	1180014	ER BUCK CHAIR COMPAN	ALL	ALL
25027	1180029	GENERAL ELECTRIC FIT	ALL	ALL
25027	1180091	ANGLO FABRICS COMPAN	ALL	ALL
25027	1180100	ZAPCO ENERGY TACTICS	ALL	ALL
25027	1180111	CINCINATTI MILACRON	ALL	ALL
25027	1180114	NEW ENGLAND PLATING	ALL	ALL
25027	1180129	GF WRIGHT STEEL & WI	ALL	ALL
25027	1180132	STANDARDFOUNDRY	ALL	ALL
25027	1180174	WORCESTER TOOL & STA	ALL	ALL
25027	1180203	WORCESTER COUNTY HOS	ALL	ALL
25027	1180244	HI TECH METALS & FIN	ALL	ALL
25027	1180340	GHM INDUSTRIES INC	ALL	ALL
25027	1180353	ADVANCED MICROSENSOR	ALL	ALL
25027	1180355	NEWARK AMERICA	ALL	ALL
25027	1180373	ZYGO TERAOPTIX	ALL	ALL
25027	1180389	ETHAN ALLEN-DUDLEY	ALL	ALL
25027	1180439	INLAND PAPERBOARD &	ALL	ALL
25027	1180484	NELMOR COMPANY	ALL	ALL
25027	1180518	JAMESBURY INCORPORAT	ALL	ALL
25027	1180556	M&H TIRE CO INC	ALL	ALL
25027	1180568	CROFT CORPORATION	ALL	ALL
25027	1180796	LINCOLN PLAZA CENTER	ALL	ALL
25027	1180994	COZ PLASTICS INC	ALL	ALL
25027	1181045	WORCESTER TAPER PIN	ALL	ALL
33011	3301100093	BATESVILLE MANUFACTURING	ALL	ALL
33015	3301500058	VENTURE SEABROOK	ALL	ALL

Appendix C – Area Source Growth Factors

Table C-1 Area Source Growth Factors by SCC Code

See Electronic File: MANE-VU_Area_gf_scc.xls

This table contains records with area source growth factors by county and SCC. The format for the tables is as follows:

Column A – County FIPS code

Column B – Source Classification Code (SCC)

Column C – EGAS_02_09 this is the EGAS 5.0 factor for projecting from 2002 to 2009

Column D – AEO5_02_09 this is the DOE AEO 2005 factor for projecting from 2002 to 2009

Column E – ST_02_09 this is the state-supplied factor for projecting from 2002 to 2009

Column F – GF_02_09 this is the final factor actually used for projecting from 2002 to 2009 (it is the state-supplied factor, if available; if no state-supplied factor, then it is the AEO2005 factor; if no AEO2005 factor, then it is the default EGAS 5.0 factor)

Column G – EGAS_02_12 this is the EGAS 5.0 factor for projecting from 2002 to 2012

Column H – AEO5_02_12 this is the DOE AEO 2005 factor for projecting from 2002 to 2012

Column I – ST_02_12 this is the state-supplied factor for projecting from 2002 to 2012

Column J – GF_02_09 this is the final factor actually used for projecting from 2002 to 2012 (it is the state-supplied factor, if available; if no state-supplied factor, then it is the AEO2005 factor; if no AEO2005 factor, then it is the default EGAS 5.0 factor)

Column K – EGAS_02_18 this is the EGAS 5.0 factor for projecting from 2002 to 2018

Column J – AEO5_02_18 this is the DOE AEO 2005 factor for projecting from 2002 to 2018

Column M– ST_02_18 this is the state-supplied factor for projecting from 2002 to 2018

Column N – GF_02_09 this is the final factor actually used for projecting from 2002 to 2012 (it is the state-supplied factor, if available; if no state-supplied factor, then it is the AEO2005 factor; if no AEO2005 factor, then it is the default EGAS 5.0 factor)

Column O – SCC description

Appendix D – Area Source Control Factors

Table D-1 Area Source Control Factors for 2001 OTC VOC Model Rules

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
AIM Coatings						
09	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
09	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
10	2401002000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings - Solvent-based;Surface Coating
10	2401003000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings - Water-based;Surface Coating
10	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
10	2401102000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings- Solve;Surface Coating
10	2401103000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings- Water;Surface Coating
11	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
11	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
11	2401100000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings;Surface Coating
11	2401200000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Other Special Purpose Coatings;Surface Coating
23	2401001000	VOC	29.50	29.50	29.50	Total: All Solvent Types;Architectural Coatings;Surface Coating
23	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
23	2401100000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings;Surface Coating
23	2401200000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Other Special Purpose Coatings;Surface Coating
24	2401002000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings - Solvent-based;Surface Coating
24	2401003000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings - Water-based;Surface Coating
24	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
24	2401008999	VOC	31.00	31.00	31.00	Solvents: NEC;Traffic Markings;Surface Coating
24	2401100000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings;Surface Coating
24	2401200000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Other Special Purpose Coatings;Surface Coating
25	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
25	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
25	2401100000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings;Surface Coating

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
25	2401200000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Other Special Purpose Coatings;Surface Coating
33	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
33	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
33	2401100000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings;Surface Coating
33	2401200000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Other Special Purpose Coatings;Surface Coating
34	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
34	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
34	2401100000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings;Surface Coating
34	2401200000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Other Special Purpose Coatings;Surface Coating
36	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
36	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
42	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
42	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
42	2401100000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings;Surface Coating
42	2401200000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Other Special Purpose Coatings;Surface Coating
44	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
44	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
50	2401001000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Architectural Coatings;Surface Coating
50	2401008000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Traffic Markings;Surface Coating
50	2401100000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Industrial Maintenance Coatings;Surface Coating
50	2401200000	VOC	31.00	31.00	31.00	Total: All Solvent Types;Other Special Purpose Coatings;Surface Coating
Consumer Products						
09	2465000000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Products/Processes;Miscellaneous Non-industrial: Consumer
10	2460100000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Personal Care Products;Miscellaneous Non-industrial: Consumer and Commerc
10	2460200000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Household Products;Miscellaneous Non-industrial: Consumer and Commerc

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
10	2460400000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Automotive Aftermarket Products;Miscellaneous Non-industrial: Consumer and Commerc
10	2460500000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Coatings and Related Products;Miscellaneous Non-industrial: Consumer and Commerc
10	2460600000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Adhesives and Sealants;Miscellaneous Non-industrial: Consumer and Commerc
10	2460800000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All FIFRA Related Products;Miscellaneous Non-industrial: Consumer and Commerc
10	2460900000	VOC	14.20	14.20	14.20	Total: All Solvent Types;Miscellaneous Products (Not Otherwise Covered);Miscellaneous Non-industrial: Consumer and Commerc
11	2460100000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Personal Care Products;Miscellaneous Non-industrial: Consumer and Commerc
11	2460200000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Household Products;Miscellaneous Non-industrial: Consumer and Commerc
11	2460400000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Automotive Aftermarket Products;Miscellaneous Non-industrial: Consumer and Commerc
11	2460500000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Coatings and Related Products;Miscellaneous Non-industrial: Consumer and Commerc
11	2460600000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Adhesives and Sealants;Miscellaneous Non-industrial: Consumer and Commerc
11	2460800000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All FIFRA Related Products;Miscellaneous Non-industrial: Consumer and Commerc
11	2460900000	VOC	14.20	14.20	14.20	Total: All Solvent Types;Miscellaneous Products (Not Otherwise Covered);Miscellaneous Non-industrial: Consumer and Commerc
23	2460100000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Personal Care Products;Miscellaneous Non-industrial: Consumer and Commerc
23	2460200000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Household Products;Miscellaneous Non-industrial: Consumer and Commerc
23	2460400000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Automotive Aftermarket Products;Miscellaneous Non-industrial: Consumer and Commerc
23	2460500000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Coatings and Related Products;Miscellaneous Non-industrial: Consumer and Commerc
23	2460600000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Adhesives and Sealants;Miscellaneous Non-industrial: Consumer and Commerc

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
23	2460800000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All FIFRA Related Products;Miscellaneous Non-industrial: Consumer and Commerc
23	2460900000	VOC	14.20	14.20	14.20	Total: All Solvent Types;Miscellaneous Products (Not Otherwise Covered);Miscellaneous Non-industrial: Consumer and Commerc
24	2465000000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Products/Processes;Miscellaneous Non-industrial: Consumer
25	2460000000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Processes;Miscellaneous Non-industrial: Consumer and Commerc
33	2460000000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Processes;Miscellaneous Non-industrial: Consumer and Commerc
34	2460100000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Personal Care Products;Miscellaneous Non-industrial: Consumer and Commerc
34	2460200000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Household Products;Miscellaneous Non-industrial: Consumer and Commerc
34	2460400000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Automotive Aftermarket Products;Miscellaneous Non-industrial: Consumer and Commerc
34	2460500000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Coatings and Related Products;Miscellaneous Non-industrial: Consumer and Commerc
34	2460600000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Adhesives and Sealants;Miscellaneous Non-industrial: Consumer and Commerc
34	2460800000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All FIFRA Related Products;Miscellaneous Non-industrial: Consumer and Commerc
34	2460900000	VOC	14.20	14.20	14.20	Total: All Solvent Types;Miscellaneous Products (Not Otherwise Covered);Miscellaneous Non-industrial: Consumer and Commerc
34	2465000000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Products/Processes;Miscellaneous Non-industrial: Consumer
36	2460000000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Processes;Miscellaneous Non-industrial: Consumer and Commerc
42	2465000000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Products/Processes;Miscellaneous Non-industrial: Consumer
44	2460100000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Personal Care Products;Miscellaneous Non-industrial: Consumer and Commerc
44	2460200000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Household Products;Miscellaneous Non-industrial: Consumer and Commerc
44	2460400000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Automotive Aftermarket Products;Miscellaneous Non-industrial: Consumer and Commerc

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
44	2460500000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Coatings and Related Products;Miscellaneous Non-industrial: Consumer and Commerc
44	2460600000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Adhesives and Sealants;Miscellaneous Non-industrial: Consumer and Commerc
44	2460800000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All FIFRA Related Products;Miscellaneous Non-industrial: Consumer and Commerc
44	2460900000	VOC	14.20	14.20	14.20	Total: All Solvent Types;Miscellaneous Products (Not Otherwise Covered);Miscellaneous Non-industrial: Consumer and Commerc
50	2460100000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Personal Care Products;Miscellaneous Non-industrial: Consumer and Commerc
50	2460200000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Household Products;Miscellaneous Non-industrial: Consumer and Commerc
50	2460400000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Automotive Aftermarket Products;Miscellaneous Non-industrial: Consumer and Commerc
50	2460500000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Coatings and Related Products;Miscellaneous Non-industrial: Consumer and Commerc
50	2460600000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All Adhesives and Sealants;Miscellaneous Non-industrial: Consumer and Commerc
50	2460800000	VOC	14.20	14.20	14.20	Total: All Solvent Types;All FIFRA Related Products;Miscellaneous Non-industrial: Consumer and Commerc
50	2460900000	VOC	14.20	14.20	14.20	Total: All Solvent Types;Miscellaneous Products (Not Otherwise Covered);Miscellaneous Non-industrial: Consumer and Commerc
Mobile Equipment Repair and Refinishing						
09	2401005000	VOC	38.00	38.00	38.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
10	2401005500	VOC	38.00	38.00	38.00	Surface Preparation Solvents;Auto Refinishing: SIC 7532;Surface Coating
10	2401005600	VOC	38.00	38.00	38.00	Primers;Auto Refinishing: SIC 7532;Surface Coating
10	2401005700	VOC	38.00	38.00	38.00	Top Coats;Auto Refinishing: SIC 7532;Surface Coating
10	2401005800	VOC	38.00	38.00	38.00	Clean-up Solvents;Auto Refinishing: SIC 7532;Surface Coating
11	2401005000	VOC	38.00	38.00	38.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
23	2401005000	VOC	38.00	38.00	38.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
24	2401005000	VOC	0.00	0.00	0.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
25	2401005000	VOC	0.00	0.00	0.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
33	2401005000	VOC	38.00	38.00	38.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
34	2401005000	VOC	19.00	19.00	19.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
36	2401005000	VOC	38.00	38.00	38.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
42	2401005000	VOC	0.00	0.00	0.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
44	2401005000	VOC	38.00	38.00	38.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
50	2401005000	VOC	38.00	38.00	38.00	Total: All Solvent Types;Auto Refinishing: SIC 7532;Surface Coating
Solvent Cleaning Operations						
09	2415000000	VOC	66.00	66.00	66.00	Total: All Solvent Types;All Processes/All Industries;Degreasing
23	2415000000	VOC	66.00	66.00	66.00	Total: All Solvent Types;All Processes/All Industries;Degreasing
23	2415030000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Electronic and Other Elec. (SIC 36): All Processes;Degreasing
23	2415045000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Miscellaneous Manufacturing (SIC 39): All Processe;Degreasing
23	2415065000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Auto Repair Services (SIC 75): All Processes;Degreasing
23	2415300000	VOC	66.00	66.00	66.00	Total: All Solvent Types;All Industries: Cold Cleaning;Degreasing
25	2415000000	VOC	7.00	7.00	7.00	Total: All Solvent Types;All Industries: Cold Cleaning;Degreasing
33	2415000000	VOC	66.00	66.00	66.00	Total: All Solvent Types;All Industries: Cold Cleaning;Degreasing
34	2415000000	VOC	17.00	17.00	17.00	Total: All Solvent Types;All Processes/All Industries;Degreasing
36	2415020000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Fabricated Metal Products (SIC 34): All Processes;Degreasing
36	2415025000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Industrial Machinery and Equipment (SIC 35): All P;Degreasing
36	2415035000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Transportation Equipment (SIC 37): All Processes;Degreasing
36	2415045000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Miscellaneous Manufacturing (SIC 39): All Processe;Degreasing
36	2415055000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Automotive Dealers (SIC 55): All Processes;Degreasing
36	2415060000	VOC	66.00	66.00	66.00	Total: All Solvent Types;Miscellaneous Repair Services (SIC 76): All Proces;Degreasing
44	2415000000	VOC	66.00	66.00	66.00	Total: All Solvent Types;All Processes/All Industries;Degreasing

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
Portable Fuel Containers						
09	2501060300	VOC	41.3	63.8	75.0	Total;Portable Containers: Residential & Com;Petroleum and Petroleum Product Storage
10	2501011010	VOC	41.3	63.8	75.0	Vapor Losses;Portable Containers: Residential;Petroleum and Petroleum Product Storage
10	2501011011	VOC	41.3	63.8	75.0	Permeation;Portable Containers: Residential;Petroleum and Petroleum Product Storage
10	2501011012	VOC	41.3	63.8	75.0	Diurnal;Portable Containers: Residential;Petroleum and Petroleum Product Storage
10	2501011015	VOC	41.3	63.8	75.0	Spillage;Portable Containers: Residential;Petroleum and Petroleum Product Storage
10	2501011016	VOC	41.3	63.8	75.0	Transport;Portable Containers: Residential;Petroleum and Petroleum Product Storage
10	2501012010	VOC	41.3	63.8	75.0	Vapor Losses;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
10	2501012011	VOC	41.3	63.8	75.0	Permeation;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
10	2501012012	VOC	41.3	63.8	75.0	Diurnal;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
10	2501012015	VOC	41.3	63.8	75.0	Spillage;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
10	2501012016	VOC	41.3	63.8	75.0	Transport;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
11	2501011011	VOC	41.3	63.8	75.0	Permeation;Portable Containers: Residential;Petroleum and Petroleum Product Storage
11	2501011012	VOC	41.3	63.8	75.0	Diurnal;Portable Containers: Residential;Petroleum and Petroleum Product Storage
11	2501011016	VOC	41.3	63.8	75.0	Transport;Portable Containers: Residential;Petroleum and Petroleum Product Storage
11	2501012011	VOC	41.3	63.8	75.0	Permeation;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
11	2501012012	VOC	41.3	63.8	75.0	Diurnal;Portable Containers: Commercial;Petroleum and Petroleum Product

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
						Storage
11	2501012016	VOC	41.3	63.8	75.0	Transport;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
23	2501060300	VOC	41.3	63.8	75.0	Total;Portable Containers: Residential & Com;Petroleum and Petroleum Product Storage
24	2501011011	VOC	48.8	71.3	75.0	Permeation;Portable Containers: Residential;Petroleum and Petroleum Product Storage
24	2501011012	VOC	48.8	71.3	75.0	Diurnal;Portable Containers: Residential;Petroleum and Petroleum Product Storage
24	2501011016	VOC	48.8	71.3	75.0	Transport;Portable Containers: Residential;Petroleum and Petroleum Product Storage
24	2501012011	VOC	48.8	71.3	75.0	Permeation;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
24	2501012012	VOC	48.8	71.3	75.0	Diurnal;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
24	2501012016	VOC	48.8	71.3	75.0	Transport;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
25	2501011000	VOC	18.8	41.3	75.0	;;
25	2501012000	VOC	18.8	41.3	75.0	;;
33	2501060300	VOC	26.3	48.8	75.0	Total;Portable Containers: Residential & Com;Petroleum and Petroleum Product Storage
34	2501000120	VOC	33.8	56.3	75.0	Gasoline;All Storage Types: Breathing Loss;Petroleum and Petroleum Product Storage
36	2501011011	VOC	48.8	71.3	75.0	Permeation;Portable Containers: Residential;Petroleum and Petroleum Product Storage
36	2501011012	VOC	48.8	71.3	75.0	Diurnal;Portable Containers: Residential;Petroleum and Petroleum Product Storage
36	2501011016	VOC	48.8	71.3	75.0	Transport;Portable Containers: Residential;Petroleum and Petroleum Product Storage
36	2501012011	VOC	48.8	71.3	75.0	Permeation;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
36	2501012012	VOC	48.8	71.3	75.0	Diurnal;Portable Containers: Commercial;Petroleum and Petroleum Product Storage

FIPSST	**SCC**	**PLLTCODE**	**CE_2009**	**CE_2012**	**CE_2018**	**SCC Description**
36	2501012016	VOC	48.8	71.3	75.0	Transport;Portable Containers: Commercial;Petroleum and Petroleum Product Storage
42	2501060300	VOC	48.8	71.3	75.0	Total;Portable Containers: Residential & Com;Petroleum and Petroleum Product Storage
44	2501060300	VOC	18.8	41.3	75.0	Total;Portable Containers: Residential & Com;Petroleum and Petroleum Product Storage
50	2501060300	VOC	18.8	41.3	75.0	Total;Portable Containers: Residential & Com;Petroleum and Petroleum Product Storage

Table D-2 Area Source Control Factors for On-Board Vapor Recovery

FIPS	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
09001	2501060101	VOC	23.81	28.57	38.10	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
09001	2501060102	VOC	23.81	28.57	38.10	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
09003	2501060101	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
09003	2501060102	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
09005	2501060101	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
09005	2501060102	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
09007	2501060101	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
09007	2501060102	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
09009	2501060101	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
09009	2501060102	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
09011	2501060101	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
09011	2501060102	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
09013	2501060101	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
09013	2501060102	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
09015	2501060101	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
09015	2501060102	VOC	23.81	33.33	38.10	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
10001	2501060100	VOC	40.54	48.65	56.76	Stage 2: Total;Gasoline Service Stations
10003	2501060100	VOC	40.54	48.65	56.76	Stage 2: Total;Gasoline Service Stations
10005	2501060100	VOC	40.54	48.65	56.76	Stage 2: Total;Gasoline Service Stations
11001	2501060100	VOC	40.54	48.65	56.76	Stage 2: Total;Gasoline Service Stations
23001	2501060100	VOC	53.68	67.65	79.41	Stage 2: Total;Gasoline Service Stations
23003	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23005	2501060100	VOC	28.57	33.33	42.86	Stage 2: Total;Gasoline Service Stations
23007	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23009	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23011	2501060100	VOC	53.68	67.65	79.41	Stage 2: Total;Gasoline Service Stations
23013	2501060100	VOC	53.68	67.65	79.41	Stage 2: Total;Gasoline Service Stations
23015	2501060100	VOC	53.68	67.65	79.41	Stage 2: Total;Gasoline Service Stations
23017	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23019	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23021	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23023	2501060100	VOC	28.57	33.33	42.86	Stage 2: Total;Gasoline Service Stations
23025	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23027	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23029	2501060100	VOC	53.80	68.35	79.75	Stage 2: Total;Gasoline Service Stations
23031	2501060100	VOC	28.57	33.33	42.86	Stage 2: Total;Gasoline Service Stations
24001	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations

FIPS	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
24003	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24005	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24009	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24011	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24013	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24015	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24017	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24019	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24021	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24023	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24025	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24027	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24029	2501060100	VOC	53.53	68.24	80.00	Stage 2: Total;Gasoline Service Stations
24031	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24033	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
24035	2501060100	VOC	53.53	68.24	80.00	Stage 2: Total;Gasoline Service Stations
24037	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24039	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24041	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24043	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24045	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24047	2501060100	VOC	54.24	68.36	80.23	Stage 2: Total;Gasoline Service Stations
24510	2501060100	VOC	26.09	34.78	43.48	Stage 2: Total;Gasoline Service Stations
25001	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25003	2501060102	VOC	38.24	50.00	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25005	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25007	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25009	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25011	2501060102	VOC	38.24	50.00	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25013	2501060102	VOC	38.24	50.00	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25015	2501060102	VOC	38.24	50.00	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25017	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25019	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25021	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25023	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25025	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
25027	2501060102	VOC	38.24	47.06	55.88	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
33001	2501060100	VOC	53.75	68.13	80.00	Stage 2: Total;Gasoline Service Stations
33003	2501060100	VOC	53.75	68.13	80.00	Stage 2: Total;Gasoline Service Stations
33005	2501060100	VOC	53.75	68.13	80.00	Stage 2: Total;Gasoline Service Stations
33007	2501060100	VOC	53.75	68.13	80.00	Stage 2: Total;Gasoline Service Stations

FIPS	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
33009	2501060100	VOC	53.75	68.13	80.00	Stage 2: Total;Gasoline Service Stations
33011	2501060100	VOC	38.24	50.00	55.88	Stage 2: Total;Gasoline Service Stations
33013	2501060100	VOC	38.24	50.00	55.88	Stage 2: Total;Gasoline Service Stations
33015	2501060100	VOC	38.24	50.00	55.88	Stage 2: Total;Gasoline Service Stations
33017	2501060100	VOC	38.24	50.00	55.88	Stage 2: Total;Gasoline Service Stations
33019	2501060100	VOC	53.75	68.13	80.00	Stage 2: Total;Gasoline Service Stations
34001	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34003	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34005	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34007	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34009	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34011	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34013	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34015	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34017	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34019	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34021	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34023	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34025	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34027	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34029	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34031	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34033	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34035	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34037	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34039	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
34041	2501060100	VOC	38.89	47.22	58.33	Stage 2: Total;Gasoline Service Stations
36001	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36003	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36005	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36007	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36009	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36011	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36013	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36015	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36017	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36019	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36021	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36023	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36025	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36027	2501060100	VOC	53.80	67.72	79.75	Stage 2: Total;Gasoline Service Stations
36029	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36031	2501060100	VOC	53.57	67.86	79.76	Stage 2: Total;Gasoline Service Stations
36033	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36035	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36037	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36039	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36041	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36043	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36045	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations

FIPS	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
36047	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36049	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36051	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36053	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36055	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36057	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36059	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36061	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36063	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36065	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36067	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36069	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36071	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36073	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36075	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36077	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36079	2501060100	VOC	53.80	67.72	79.75	Stage 2: Total;Gasoline Service Stations
36081	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36083	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36085	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36087	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36089	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36091	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36093	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36095	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36097	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36099	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36101	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36103	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36105	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36107	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36109	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36111	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36113	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36115	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36117	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36119	2501060100	VOC	34.48	41.38	51.72	Stage 2: Total;Gasoline Service Stations
36121	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
36123	2501060100	VOC	54.29	68.57	80.00	Stage 2: Total;Gasoline Service Stations
42001	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42003	2501060102	VOC	26.09	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42005	2501060102	VOC	26.09	34.78	39.13	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42007	2501060102	VOC	26.09	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42009	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42011	2501060101	VOC	26.09	34.78	39.13	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42013	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service

FIPS	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
						Stations
42015	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42017	2501060102	VOC	30.43	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42019	2501060102	VOC	26.09	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42021	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42023	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42025	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42027	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42029	2501060102	VOC	30.43	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42031	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42033	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42035	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42037	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42039	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42041	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42043	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42045	2501060102	VOC	30.43	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42047	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42049	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42051	2501060102	VOC	26.09	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42053	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42055	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42057	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42059	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42061	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42063	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42065	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42067	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42069	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42071	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42073	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service

FIPS	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
						Stations
42075	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42077	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42079	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42081	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42083	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42085	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42087	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42089	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42091	2501060102	VOC	30.43	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42093	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42095	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42097	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42099	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42101	2501060102	VOC	30.43	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42103	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42105	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42107	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42109	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42111	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42113	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42115	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42117	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42119	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42121	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42123	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42125	2501060102	VOC	26.09	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42127	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42129	2501060102	VOC	26.09	34.78	43.48	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
42131	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
42133	2501060101	VOC	53.98	68.75	80.11	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service

FIPS	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
						Stations
44001	2501060000	VOC	38.24	50.00	55.88	Total: All Gasoline/All Processes;Gasoline Service Stations
44003	2501060000	VOC	38.24	50.00	55.88	Total: All Gasoline/All Processes;Gasoline Service Stations
44005	2501060000	VOC	38.24	50.00	55.88	Total: All Gasoline/All Processes;Gasoline Service Stations
44007	2501060000	VOC	38.24	50.00	55.88	Total: All Gasoline/All Processes;Gasoline Service Stations
44009	2501060000	VOC	38.24	50.00	55.88	Total: All Gasoline/All Processes;Gasoline Service Stations
50001	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50001	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50001	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50003	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50003	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50003	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50005	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50005	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50005	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50007	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50007	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50007	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50009	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50009	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50009	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50011	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50011	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50011	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50013	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50013	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50013	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50015	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50015	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50015	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50017	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50017	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50017	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50019	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50019	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50019	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50021	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service

FIPS	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018	SCC Description
						Stations
50021	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50021	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50023	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50023	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50023	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50025	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50025	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50025	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations
50027	2501060101	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Uncontrolled;Gasoline Service Stations
50027	2501060102	VOC	37.14	48.57	57.14	Stage 2: Displacement Loss/Controlled;Gasoline Service Stations
50027	2501060103	VOC	37.14	48.57	57.14	Stage 2: Spillage;Gasoline Service Stations

Table D-3 Area Source Growth/Control Factors for Residential Wood Combustion

SCC	SCC Description	Assumptions	Growth and Control Factor		
			2002-2009	**2002-2012**	**2002-2018**
2104008000	Total: Woodstoves and Fireplaces	1 - 0.01056*(Year-2002) (Assumes 19.4% fireplaces 71.6%old woodstoves 9.1%new woodstoves)	0.926	0.894	0.831
2104008001	Fireplaces: General	Increase 1%/yr: 1 + 0.01*(Year-2002)	1.070	1.100	1.160
2104008002	Fireplaces: Insert; non-EPA certified	Decrease 2%/yr: 1 - 0.02*(Year-2002)	0.860	0.800	0.680
2104008003	Fireplaces: Insert; EPA certified; non-catalytic	Increase 2%/yr: 1 + 0.02*(Year-2002)	1.140	1.200	1.320
2104008004	Fireplaces: Insert; EPA certified; catalytic	Increase 2%/yr (same as 2104008003)	1.140	1.200	1.320
2104008010	Woodstoves: General	Decrease 2%/yr (same as 2104008002)	0.860	0.800	0.680
2104008030	Catalytic Woodstoves: General	Increase 2%/yr (same as 2104008003)	1.140	1.200	1.320
2104008050	Non-catalytic Woodstoves: EPA certified	Increase 2%/yr (same as 2104008003)	1.140	1.200	1.320
2104008051	Non-catalytic Woodstoves: Non-EPA certified	Decrease 2%/yr (same as 2104008002)	0.860	0.800	0.680
2104008052	Non-catalytic Woodstoves: Low Emitting	Increase 2%/yr (same as 2104008003)	1.140	1.200	1.320
2104008053	Non-catalytic Woodstoves: Pellet Fired	Increase 2%/yr (same as 2104008003)	1.140	1.200	1.320

Table E-1 NonEGU BOTW Control Factors for Adhesives and Sealants Application, Asphalt Production Plants, Cement Kilns, and Glass/Fiberglass Furnaces

FIPS	SITEID	EU ID	PROCESS ID	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
Control Measure: Adhesives and Sealants Application								
09003	6484	R0131	01	40200701	VOC	64.40	64.40	64.40
09003	6484	R0132	01	40200701	VOC	64.40	64.40	64.40
09015	0647	P0085	01	40200701	VOC	64.40	64.40	64.40
10001	1000100004	003	2	40200701	VOC	64.40	64.40	64.40
10001	1000100004	005	2	40200701	VOC	64.40	64.40	64.40
10001	1000100004	005	3	40200701	VOC	64.40	64.40	64.40
10001	1000100004	005	4	40200701	VOC	64.40	64.40	64.40
10001	1000100004	005	5	40200701	VOC	64.40	64.40	64.40
10003	1000300365	002	2	40200706	VOC	64.40	64.40	64.40
10003	1000300365	002	1	40200710	VOC	64.40	64.40	64.40
23001	2300100076	003	2	40200701	VOC	64.40	64.40	64.40
24003	003-0250	232	01F232	40200701	VOC	64.40	64.40	64.40
24003	003-0250	232	01S232	40200701	VOC	64.40	64.40	64.40
24005	005-2407	17	01F17	40200701	VOC	64.40	64.40	64.40
24005	005-2407	17	01S17	40200701	VOC	64.40	64.40	64.40
24025	025-0006	45	01F45	40200710	VOC	64.40	64.40	64.40
24025	025-0006	45	01S45	40200710	VOC	64.40	64.40	64.40
24025	025-0423	5	01F5	40200701	VOC	64.40	64.40	64.40
24025	025-0423	5	01S5	40200701	VOC	64.40	64.40	64.40
24025	025-0423	6	01F6	40200701	VOC	64.40	64.40	64.40
24025	025-0423	6	01S6	40200701	VOC	64.40	64.40	64.40
24025	025-0423	7	01F7	40200701	VOC	64.40	64.40	64.40
24025	025-0423	7	01S7	40200701	VOC	64.40	64.40	64.40
24045	045-0082	12	01F12	40200710	VOC	64.40	64.40	64.40
24045	045-0082	12	01S12	40200710	VOC	64.40	64.40	64.40
25005	1200077	12	0108	40200701	VOC	64.40	64.40	64.40
25005	1200100	23	0111	40200701	VOC	64.40	64.40	64.40
25005	1200100	26	0114	40200701	VOC	64.40	64.40	64.40
25005	1200100	28	0116	40200701	VOC	64.40	64.40	64.40
25005	1200101	08	0107	40200701	VOC	64.40	64.40	64.40
25005	1200101	09	0108	40200706	VOC	64.40	64.40	64.40
25005	1200101	10	0109	40200701	VOC	64.40	64.40	64.40
25005	1200101	11	0110	40200701	VOC	64.40	64.40	64.40
25005	1200101	12	0111	40200701	VOC	64.40	64.40	64.40
25005	1200183	07	0203	40200701	VOC	64.40	64.40	64.40
25005	1200388	04	0104	40200701	VOC	64.40	64.40	64.40
25005	1200388	05	0105	40200701	VOC	64.40	64.40	64.40
25005	1200388	05	0205	40200701	VOC	64.40	64.40	64.40
25005	1200509	04	0104	40200701	VOC	64.40	64.40	64.40
25005	1200585	02	0102	40200710	VOC	64.40	64.40	64.40
25005	1200673	07	0107	40200710	VOC	64.40	64.40	64.40

FIPS	**SITEID**	**EU ID**	**PROCESS ID**	**SCC**	**PLLTCODE**	**CE_2009**	**CE_2012**	**CE_2018**
25005	1200707	08	0106	40200710	VOC	64.40	64.40	64.40
25005	1200851	11	0110	40200710	VOC	64.40	64.40	64.40
25009	1190683	03	0103	40200706	VOC	64.40	64.40	64.40
25009	1190690	09	0108	40200710	VOC	64.40	64.40	64.40
25009	1210026	15	0115	40200710	VOC	64.40	64.40	64.40
25009	1210046	01	0101	40200706	VOC	64.40	64.40	64.40
25009	1210083	05	0104	40200710	VOC	64.40	64.40	64.40
25009	1210093	09	0209	40200701	VOC	64.40	64.40	64.40
25009	1210110	01	0101	40200701	VOC	64.40	64.40	64.40
25009	1210212	30	0321	40200706	VOC	64.40	64.40	64.40
25009	1210212	30	0721	40200706	VOC	64.40	64.40	64.40
25009	1210212	32	0322	40200706	VOC	64.40	64.40	64.40
25009	1210212	32	0622	40200706	VOC	64.40	64.40	64.40
25009	1210212	32	0922	40200706	VOC	64.40	64.40	64.40
25009	1210276	03	0102	40200701	VOC	64.40	64.40	64.40
25009	1210332	01	0101	40200701	VOC	64.40	64.40	64.40
25009	1210332	02	0102	40200701	VOC	64.40	64.40	64.40
25009	1210332	03	0103	40200701	VOC	64.40	64.40	64.40
25009	1210341	10	0110	40200710	VOC	64.40	64.40	64.40
25009	1211013	07	0105	40200710	VOC	64.40	64.40	64.40
25009	1211013	08	0306	40200710	VOC	64.40	64.40	64.40
25009	1211013	33	0331	40200701	VOC	64.40	64.40	64.40
25009	1211013	72	0259	40200710	VOC	64.40	64.40	64.40
25009	1211013	89	0253	40200710	VOC	64.40	64.40	64.40
25013	0420145	16	0112	40200710	VOC	64.40	64.40	64.40
25013	0420213	01	0201	40200701	VOC	64.40	64.40	64.40
25013	0420260	02	0102	40200710	VOC	64.40	64.40	64.40
25013	0420265	06	0105	40200701	VOC	64.40	64.40	64.40
25013	0420561	01	0101	40200701	VOC	64.40	64.40	64.40
25013	0420798	05	0105	40200710	VOC	64.40	64.40	64.40
25013	0420821	10	0106	40200701	VOC	64.40	64.40	64.40
25015	0420558	01	0101	40200710	VOC	64.40	64.40	64.40
25017	1180795	02	0102	40200706	VOC	64.40	64.40	64.40
25017	1180795	03	0103	40200706	VOC	64.40	64.40	64.40
25017	1180795	04	0104	40200706	VOC	64.40	64.40	64.40
25017	1180795	05	0105	40200706	VOC	64.40	64.40	64.40
25017	1180795	06	0106	40200706	VOC	64.40	64.40	64.40
25017	1180795	07	0107	40200701	VOC	64.40	64.40	64.40
25017	1180795	08	0108	40200701	VOC	64.40	64.40	64.40
25017	1180795	09	0109	40200701	VOC	64.40	64.40	64.40
25017	1190355	05	0101	40200706	VOC	64.40	64.40	64.40
25017	1190424	04	0104	40200701	VOC	64.40	64.40	64.40
25017	1190424	08	0106	40200701	VOC	64.40	64.40	64.40
25017	1190424	11	0107	40200701	VOC	64.40	64.40	64.40
25017	1190424	20	0110	40200701	VOC	64.40	64.40	64.40
25017	1190424	24	0111	40200701	VOC	64.40	64.40	64.40
25017	1190424	28	0112	40200701	VOC	64.40	64.40	64.40

FIPS	SITEID	EU ID	PROCESS ID	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
25017	1190424	32	0213	40200701	VOC	64.40	64.40	64.40
25017	1190424	37	0117	40200701	VOC	64.40	64.40	64.40
25017	1190429	06	0106	40200710	VOC	64.40	64.40	64.40
25017	1190560	02	0101	40200710	VOC	64.40	64.40	64.40
25017	1190560	23	0106	40200710	VOC	64.40	64.40	64.40
25017	1190585	08	0104	40200706	VOC	64.40	64.40	64.40
25017	1190585	17	0106	40200710	VOC	64.40	64.40	64.40
25017	1190692	09	0107	40200701	VOC	64.40	64.40	64.40
25017	1190692	10	0108	40200701	VOC	64.40	64.40	64.40
25017	1190692	11	0108	40200701	VOC	64.40	64.40	64.40
25017	1190953	04	0104	40200710	VOC	64.40	64.40	64.40
25017	1190999	11	0111	40200710	VOC	64.40	64.40	64.40
25017	1190999	11	0211	40200710	VOC	64.40	64.40	64.40
25017	1190999	13	0313	40200710	VOC	64.40	64.40	64.40
25017	1191104	03	0103	40200710	VOC	64.40	64.40	64.40
25017	1191192	05	0104	40200701	VOC	64.40	64.40	64.40
25017	1191296	26	0116	40200701	VOC	64.40	64.40	64.40
25017	1191296	27	0117	40200701	VOC	64.40	64.40	64.40
25017	1191471	04	0103	40200710	VOC	64.40	64.40	64.40
25017	1191564	08	0108	40200710	VOC	64.40	64.40	64.40
25017	1191844	53	0135	40200710	VOC	64.40	64.40	64.40
25017	1191844	53	0335	40200710	VOC	64.40	64.40	64.40
25017	1192051	12	0107	40200710	VOC	64.40	64.40	64.40
25017	1192051	26	0115	40200710	VOC	64.40	64.40	64.40
25017	1210036	03	0103	40200701	VOC	64.40	64.40	64.40
25017	1210036	05	0104	40200710	VOC	64.40	64.40	64.40
25017	1210036	07	0105	40200701	VOC	64.40	64.40	64.40
25017	1210373	01	0101	40200701	VOC	64.40	64.40	64.40
25017	1210373	02	0102	40200701	VOC	64.40	64.40	64.40
25017	1210373	03	0103	40200701	VOC	64.40	64.40	64.40
25017	1210373	04	0104	40200701	VOC	64.40	64.40	64.40
25017	1210373	04	0204	40200701	VOC	64.40	64.40	64.40
25017	1210373	05	0105	40200701	VOC	64.40	64.40	64.40
25017	1210373	05	0205	40200701	VOC	64.40	64.40	64.40
25017	1210373	06	0106	40200701	VOC	64.40	64.40	64.40
25017	1210373	06	0206	40200701	VOC	64.40	64.40	64.40
25017	1210373	09	0109	40200701	VOC	64.40	64.40	64.40
25017	1210373	10	0110	40200701	VOC	64.40	64.40	64.40
25017	1210912	02	0202	40200710	VOC	64.40	64.40	64.40
25021	1190319	04	0103	40200710	VOC	64.40	64.40	64.40
25021	1190319	11	0111	40200710	VOC	64.40	64.40	64.40
25021	1190569	23	0215	40200710	VOC	64.40	64.40	64.40
25021	1192106	03	0103	40200710	VOC	64.40	64.40	64.40
25021	1192121	07	0107	40200701	VOC	64.40	64.40	64.40
25021	1192131	03	0103	40200710	VOC	64.40	64.40	64.40
25021	1192491	07	0107	40200701	VOC	64.40	64.40	64.40
25021	1192491	08	0108	40200701	VOC	64.40	64.40	64.40

FIPS	SITEID	EU ID	PROCESS ID	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
25021	1200125	55	0146	40200710	VOC	64.40	64.40	64.40
25021	1200125	56	0147	40200710	VOC	64.40	64.40	64.40
25021	1200127	10	0209	40200710	VOC	64.40	64.40	64.40
25021	1200228	04	0203	40200710	VOC	64.40	64.40	64.40
25021	1200452	04	0102	40200701	VOC	64.40	64.40	64.40
25023	1192198	11	0107	40200710	VOC	64.40	64.40	64.40
25023	1192198	12	0108	40200710	VOC	64.40	64.40	64.40
25023	1192198	19	0109	40200710	VOC	64.40	64.40	64.40
25023	1192198	23	0109	40200710	VOC	64.40	64.40	64.40
25023	1192198	25	0109	40200710	VOC	64.40	64.40	64.40
25023	1192198	26	0109	40200710	VOC	64.40	64.40	64.40
25023	1192203	01	0101	40200710	VOC	64.40	64.40	64.40
25023	1192237	08	0102	40200710	VOC	64.40	64.40	64.40
25023	1192436	09	0105	40200701	VOC	64.40	64.40	64.40
25023	1200177	05	0105	40200701	VOC	64.40	64.40	64.40
25023	1200637	04	0104	40200710	VOC	64.40	64.40	64.40
25023	1200637	07	0105	40200707	VOC	64.40	64.40	64.40
25025	1191397	05	0106	40200701	VOC	64.40	64.40	64.40
25025	1191397	06	0107	40200701	VOC	64.40	64.40	64.40
25027	1180025	01	0301	40200710	VOC	64.40	64.40	64.40
25027	1180115	17	0209	40200701	VOC	64.40	64.40	64.40
25027	1180115	25	0311	40200710	VOC	64.40	64.40	64.40
25027	1180115	36	0117	40200710	VOC	64.40	64.40	64.40
25027	1180115	39	0118	40200701	VOC	64.40	64.40	64.40
25027	1180115	77	0251	40200710	VOC	64.40	64.40	64.40
25027	1180225	04	0104	40200710	VOC	64.40	64.40	64.40
25027	1180265	05	0205	40200701	VOC	64.40	64.40	64.40
25027	1180310	03	0203	40200701	VOC	64.40	64.40	64.40
25027	1180310	03	0303	40200701	VOC	64.40	64.40	64.40
25027	1180505	07	0107	40200701	VOC	64.40	64.40	64.40
25027	1180505	23	0123	40200710	VOC	64.40	64.40	64.40
25027	1180998	27	0111	40200710	VOC	64.40	64.40	64.40
25027	1180998	30	0113	40200701	VOC	64.40	64.40	64.40
25027	1200856	12	0110	40200701	VOC	64.40	64.40	64.40
25027	1200856	13	0111	40200701	VOC	64.40	64.40	64.40
33011	3301100076	004	1	40200701	VOC	64.40	64.40	64.40
33011	3301100076	005	1	40200701	VOC	64.40	64.40	64.40
33011	3301100076	009	1	40200701	VOC	64.40	64.40	64.40
33017	3301700010	001	1	40200701	VOC	64.40	64.40	64.40
33017	3301700010	002	1	40200701	VOC	64.40	64.40	64.40
36063	9290900018	ADHES1	HM1FP	40200701	VOC	64.40	64.40	64.40
36069	8329900028	000005	WABFP	40200701	VOC	64.40	64.40	64.40
36103	1473000001	EI0001	E10EI	40200701	VOC	64.40	64.40	64.40
36103	1473000001	U00002	103FP	40200706	VOC	64.40	64.40	64.40
36115	5533000016	U00011	SL2FP	40200710	VOC	64.40	64.40	64.40
36117	8543600007	1MLDRB	SC3FP	40200701	VOC	64.40	64.40	64.40
36117	8543600007	2KLZRS	SC2FP	40200701	VOC	64.40	64.40	64.40

FIPS	SITEID	EU ID	PROCESS ID	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
42001	420010009	103	1	40200706	VOC	64.40	64.40	64.40
42013	420130480	101	2	40200701	VOC	64.40	64.40	64.40
42017	420171041	101	1	40200701	VOC	64.40	64.40	64.40
42019	420190029	104	1	40200701	VOC	64.40	64.40	64.40
42019	420190029	105	1	40200701	VOC	64.40	64.40	64.40
42019	420190090	102	1	40200701	VOC	64.40	64.40	64.40
42019	420190090	102	2	40200701	VOC	64.40	64.40	64.40
42019	420190090	102	3	40200701	VOC	64.40	64.40	64.40
42019	420190090	102	4	40200701	VOC	64.40	64.40	64.40
42019	420190090	102	5	40200701	VOC	64.40	64.40	64.40
42019	420190090	102	6	40200701	VOC	64.40	64.40	64.40
42035	420350429	P105	1	40200710	VOC	64.40	64.40	64.40
42035	420350429	P106	1	40200710	VOC	64.40	64.40	64.40
42039	420390013	106	1	40200707	VOC	64.40	64.40	64.40
42039	420390014	102	1	40200701	VOC	64.40	64.40	64.40
42039	420390014	103	1	40200701	VOC	64.40	64.40	64.40
42039	420390014	104	1	40200701	VOC	64.40	64.40	64.40
42039	420390014	105	1	40200701	VOC	64.40	64.40	64.40
42045	420450954	121	1	40200701	VOC	64.40	64.40	64.40
42055	420550022	100	1	40200706	VOC	64.40	64.40	64.40
42055	420550022	101	1	40200706	VOC	64.40	64.40	64.40
42061	420610016	104	1	40200701	VOC	64.40	64.40	64.40
42061	420610016	105	1	40200701	VOC	64.40	64.40	64.40
42061	420610032	101	2	40200701	VOC	64.40	64.40	64.40
42061	420610032	101	4	40200701	VOC	64.40	64.40	64.40
42061	420610032	101	6	40200701	VOC	64.40	64.40	64.40
42061	420610032	102	2	40200701	VOC	64.40	64.40	64.40
42061	420610032	102	4	40200701	VOC	64.40	64.40	64.40
42061	420610032	102	6	40200701	VOC	64.40	64.40	64.40
42061	420610032	103	2	40200701	VOC	64.40	64.40	64.40
42061	420610032	103	4	40200701	VOC	64.40	64.40	64.40
42069	420690023	107	1	40200701	VOC	64.40	64.40	64.40
42069	420690023	108	1	40200701	VOC	64.40	64.40	64.40
42071	420710802	102	1	40200710	VOC	64.40	64.40	64.40
42071	420710804	102	1	40200710	VOC	64.40	64.40	64.40
42077	420770071	101	1	40200710	VOC	64.40	64.40	64.40
42077	420770071	101	2	40200710	VOC	64.40	64.40	64.40
42077	420770071	102	1	40200710	VOC	64.40	64.40	64.40
42077	420770071	102	2	40200710	VOC	64.40	64.40	64.40
42077	420770071	103	1	40200710	VOC	64.40	64.40	64.40
42077	420770071	104	1	40200710	VOC	64.40	64.40	64.40
42077	420770071	105	1	40200710	VOC	64.40	64.40	64.40
42081	420810039	113	1	40200710	VOC	64.40	64.40	64.40
42081	420810559	P104	1	40200710	VOC	64.40	64.40	64.40
42091	420910826	002	1	40200701	VOC	64.40	64.40	64.40
42097	420970001	105	1	40200710	VOC	64.40	64.40	64.40
42097	420970001	201	1	40200710	VOC	64.40	64.40	64.40

FIPS	SITEID	EU ID	PROCESS ID	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
42097	420970001	202	1	40200710	VOC	64.40	64.40	64.40
42097	420970034	104	1	40200710	VOC	64.40	64.40	64.40
42097	420970034	105A	1	40200710	VOC	64.40	64.40	64.40
42101	4210101591	004	1	40200701	VOC	64.40	64.40	64.40
42101	4210102051	005	10	40200712	VOC	64.40	64.40	64.40
42101	4210102051	005	11	40200712	VOC	64.40	64.40	64.40
42101	4210102051	005	12	40200712	VOC	64.40	64.40	64.40
42101	4210102051	006	5	40200712	VOC	64.40	64.40	64.40
42101	4210102051	007	6	40200712	VOC	64.40	64.40	64.40
42101	4210102051	008	14	40200712	VOC	64.40	64.40	64.40
42101	4210102051	009	7	40200712	VOC	64.40	64.40	64.40
42101	4210103217	010	2	40200710	VOC	64.40	64.40	64.40
42109	421090001	113	1	40200710	VOC	64.40	64.40	64.40
42109	421090001	140	1	40200710	VOC	64.40	64.40	64.40
42119	421190477	P101	1	40200710	VOC	64.40	64.40	64.40
42129	421290071	105	1	40200701	VOC	64.40	64.40	64.40
42129	421290311	101	1	40200701	VOC	64.40	64.40	64.40
42133	421330034	103	1	40200701	VOC	64.40	64.40	64.40
42133	421330055	101	1	40200706	VOC	64.40	64.40	64.40
42133	421330055	101	2	40200706	VOC	64.40	64.40	64.40
44003	AIR1438	8	8	40200710	VOC	64.40	64.40	64.40
44007	AIR1859	2	2	40200701	VOC	64.40	64.40	64.40
44007	AIR3850	1	1	40200701	VOC	64.40	64.40	64.40
44007	AIR537	2	2	40200710	VOC	64.40	64.40	64.40
44009	AIR594	7	7	40200710	VOC	64.40	64.40	64.40
50005	9	4	1	40200701	VOC	64.40	64.40	64.40
Control Measure: Asphalt Production Plants								
34001	70003	U101	OS1	30500207	NOX	0.00	35.00	35.00
34001	70003	U101	OS2	30500207	NOX	0.00	35.00	35.00
34001	70003	U12	OS0	30500207	NOX	0.00	35.00	35.00
34001	70003	U13	OS0	30500207	NOX	0.00	35.00	35.00
34001	70003	U6	OS1	30500207	NOX	0.00	35.00	35.00
34001	70015	U401	OS1601	30500207	NOX	0.00	35.00	35.00
34001	70015	U401	OS2101	30500207	NOX	0.00	35.00	35.00
34001	70015	U401	OS401	30500207	NOX	0.00	35.00	35.00
34007	50373	U11	OS1	30500207	NOX	0.00	35.00	35.00
34007	50373	U6	OS1	30500207	NOX	0.00	35.00	35.00
34009	73014	U9	OS3	30500207	NOX	0.00	35.00	35.00
34009	73014	U9	OS7	30500207	NOX	0.00	35.00	35.00
34013	05005	U2	OS1	30500207	NOX	0.00	35.00	35.00
34015	55261	U4	OS1	30500207	NOX	0.00	35.00	35.00
34017	11171	U2	OS1	30500207	NOX	0.00	35.00	35.00
34021	60031	U6	OS1	30500207	NOX	0.00	35.00	35.00
34023	15129	U7	OS1	30500207	NOX	0.00	35.00	35.00
34025	20022	U1	OS1	30500207	NOX	0.00	35.00	35.00
34025	20023	U2	OS1	30500207	NOX	0.00	35.00	35.00
34025	20025	U26	OS1	30500207	NOX	0.00	35.00	35.00

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34025	20025	U3	OS2	30500207	NOX	0.00	35.00	35.00
34027	25009	U13	OS1	30500207	NOX	0.00	35.00	35.00
34027	25009	U2	OS1	30500207	NOX	0.00	35.00	35.00
34027	25268	U100	OS101	30500207	NOX	0.00	35.00	35.00
34027	25268	U1601	OS1601	30500207	NOX	0.00	35.00	35.00
34027	25268	U1601	OS1602	30500207	NOX	0.00	35.00	35.00
34029	78010	U1500	OS1501	30500207	NOX	0.00	35.00	35.00
34029	78010	U1500	OS1502	30500207	NOX	0.00	35.00	35.00
34029	78010	U1601	OS1601	30500207	NOX	0.00	35.00	35.00
34029	78010	U900	OS1	30500207	NOX	0.00	35.00	35.00
34029	78012	U101	OS1	30500207	NOX	0.00	35.00	35.00
34029	78014	U2	OS1	30500207	NOX	0.00	35.00	35.00
34031	30005	U100	OS113	30500207	NOX	0.00	35.00	35.00
34031	30005	U2300	OS2301	30500207	NOX	0.00	35.00	35.00
34031	30005	U2300	OS2332	30500207	NOX	0.00	35.00	35.00
34031	30085	U100	OS201	30500207	NOX	0.00	35.00	35.00
34031	30085	U100	OS901	30500207	NOX	0.00	35.00	35.00
34031	30085	U100	OS903	30500207	NOX	0.00	35.00	35.00
34035	35014	U100	OS113	30500207	NOX	0.00	35.00	35.00
34035	35014	U100	OS2301	30500207	NOX	0.00	35.00	35.00
34035	36009	U1000	OS1201	30500207	NOX	0.00	35.00	35.00
34035	36009	U1000	OS1202	30500207	NOX	0.00	35.00	35.00
34035	36009	U1000	OS1301	30500207	NOX	0.00	35.00	35.00
34035	36009	U1000	OS1401	30500207	NOX	0.00	35.00	35.00
34037	83008	U4	OS1	30500207	NOX	0.00	35.00	35.00
36081	2630200138	D00001	P01FP	30500251	NOX	35.00	35.00	35.00
36085	2640300031	3ADRYR	302FP	30500251	NOX	35.00	35.00	35.00
36119	3550800247	1MIXER	001FP	30500205	NOX	35.00	35.00	35.00
Control Measure: Cement Kilns								
23013	2301300028	001	1	30500706	NOX	60.00	60.00	60.00
24013	013-0012	39	01S39	30500606	NOX	46.67	46.67	46.67
24021	021-0013	21	01S21	30500706	NOX	46.67	46.67	46.67
24021	021-0013	22	01S22	30500706	NOX	46.67	46.67	46.67
24043	043-0008	24	01S24	30500606	NOX	46.67	46.67	46.67
36001	4012200004	U00002	OX1FP	30501202	NOX	70.00	70.00	70.00
36001	4012200004	U00003	FZ1FP	30501204	NOX	70.00	70.00	70.00
36001	4012200004	U00003	FZ2FP	30501204	NOX	70.00	70.00	70.00
36001	4012200004	U00003	SS1FP	30501206	NOX	70.00	70.00	70.00
36001	4012200004	U00012	OX2FP	30501202	NOX	70.00	70.00	70.00
36001	4012200004	U00013	FC2FP	30501204	NOX	70.00	70.00	70.00
36001	4012400001	041000	K12FP	30500706	NOX	20.00	20.00	20.00
36039	4192600021	U00K18	00CEP	30500706	NOX	20.00	20.00	20.00
36113	5520500013	0UKILN	G02FP	30500606	NOX	20.00	20.00	20.00
42019	420190024	101	4	30500706	NOX	0.00	52.38	52.38
42019	420190024	121	4	30500706	NOX	0.00	52.38	52.38
42073	420730024	226	1	30500606	NOX	0.00	54.29	54.29
42073	420730024	227	1	30500606	NOX	0.00	60.00	60.00

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42073	420730024	228	1	30500606	NOX	0.00	54.18	54.18
42073	420730026	501	1	30500706	NOX	0.00	56.52	56.52
42073	420730026	502	1	30500706	NOX	0.00	56.52	56.52
42077	420770019	101	2	30500606	NOX	0.00	54.40	54.40
42079	420790013	101	1	30501201	NOX	85.00	85.00	85.00
42079	420790013	102	1	30501201	NOX	85.00	85.00	85.00
42079	420790013	103	1	30501204	NOX	85.00	85.00	85.00
42079	420790013	104	1	30501204	NOX	85.00	85.00	85.00
42079	420790060	104	1	30501301	NOX	85.00	85.00	85.00
42095	420950006	102	1	30500606	NOX	0.00	57.04	57.04
42095	420950006	122	1	30500606	NOX	0.00	57.04	57.04
42095	420950012	101	2	30500706	NOX	0.00	45.21	45.21
42095	420950012	102	2	30500706	NOX	0.00	45.21	45.21
42095	420950045	142	1	30500606	NOX	0.00	32.20	32.20
42095	420950045	143	1	30500606	NOX	0.00	32.20	32.20
42095	420950127	101	1	30500606	NOX	0.00	32.20	32.20
42095	420950127	102	1	30500606	NOX	0.00	32.20	32.20
42095	420950127	103	1	30500606	NOX	0.00	32.20	32.20
42095	420950127	104	1	30500606	NOX	0.00	32.20	32.20
42133	421330060	200	4	39000602	NOX	0.00	45.21	45.21
Control Measure: Glass and Fiberglass Furnaces								
24510	510-0285	10	01S10	30501402	NOX	85.00	85.00	85.00
25027	1200856	04	0304	30501402	NOX	85.00	85.00	85.00
25027	1200856	05	0304	30501402	NOX	85.00	85.00	85.00
34005	45982	U6	OS0	39999991	NOX	0.00	20.00	20.00
34011	75475	U1	OS1	30501401	NOX	0.00	20.00	20.00
34011	75475	U3	OS1	30501401	NOX	0.00	20.00	20.00
34011	75475	U35	OS1	30501401	NOX	0.00	20.00	20.00
34011	75475	U37	OS1	30501401	NOX	0.00	20.00	20.00
34011	75475	U5	OS1	30501401	NOX	0.00	20.00	20.00
34011	75503	U2	OS1001	30501401	NOX	0.00	20.00	20.00
34011	75503	U3	OS1	30501401	NOX	0.00	20.00	20.00
34011	75503	U4	OS1	30501401	NOX	0.00	20.00	20.00
34011	75503	U5	OS1	30501401	NOX	0.00	20.00	20.00
34011	75505	U12	OS1	30599999	NOX	0.00	20.00	20.00
34011	75505	U143	OS1	30599999	NOX	0.00	20.00	20.00
34011	75505	U144	OS1	30599999	NOX	0.00	20.00	20.00
34011	75505	U146	OS1	30599999	NOX	0.00	20.00	20.00
34011	75505	U150	OS1	30599999	NOX	0.00	20.00	20.00
34011	75505	U151	OS1	30599999	NOX	0.00	20.00	20.00
34011	75505	U6	OS1	30599999	NOX	0.00	20.00	20.00
34011	75506	U1	OS1	30501401	NOX	0.00	20.00	20.00
34011	75506	U1	OS3	30501401	NOX	0.00	20.00	20.00
34023	18070	U1	OS1	30501401	NOX	0.00	20.00	20.00
34033	65499	U1	OS1	30501401	NOX	0.00	20.00	20.00
34033	65499	U2	OS1	30501401	NOX	0.00	20.00	20.00
34033	65499	U3	OS1	30501401	NOX	0.00	20.00	20.00

FIPS	SITEID	EU ID	PROCESS ID	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
36001	4010300016	KILNSG	10BEI	39001399	NOX	20.00	20.00	20.00
36001	4010300016	KILNSG	KNFFP	39001399	NOX	20.00	20.00	20.00
36001	4012200004	EI0001	E20EI	39000689	NOX	70.00	70.00	70.00
36011	7055200004	AFURNC	FRNFP	30501402	NOX	70.00	70.00	70.00
36015	8070400036	000001	O1AFP	30501402	NOX	70.00	70.00	70.00
36069	8320500041	UFURNC	FURFP	30501403	NOX	70.00	70.00	70.00
36089	6403000002	U00001	101FP	30501401	NOX	70.00	70.00	70.00
36089	6403000002	U00003	300FP	30501416	NOX	70.00	70.00	70.00
36101	8460300008	PCCTNK	GL2FP	30501416	NOX	70.00	70.00	70.00
42003	4200300164	003	1	30501404	NOX	85.00	85.00	85.00
42003	4200300164	007	1	30501404	NOX	85.00	85.00	85.00
42003	4200300164	008	1	30501404	NOX	85.00	85.00	85.00
42003	4200300165	P01	1	30501402	NOX	85.00	85.00	85.00
42003	4200300165	P02	1	30501402	NOX	85.00	85.00	85.00
42003	4200300165	P04	1	30501402	NOX	85.00	85.00	85.00
42003	4200300227	003	1	30590003	NOX	85.00	85.00	85.00
42003	4200300227	003	2	30590003	NOX	85.00	85.00	85.00
42003	4200300342	002	1	30501403	NOX	85.00	85.00	85.00
42003	4200300342	002	3	30501403	NOX	85.00	85.00	85.00
42007	420070012	103	1	30501402	NOX	85.00	85.00	85.00
42007	420070012	104	1	30501408	NOX	85.00	85.00	85.00
42007	420070012	105	1	30501408	NOX	85.00	85.00	85.00
42007	420070022	102	1	30501799	NOX	85.00	85.00	85.00
42027	420270021	P101	1	30501404	NOX	85.00	85.00	85.00
42027	420270021	P102	1	30501404	NOX	85.00	85.00	85.00
42027	420270021	P102	3	30501404	NOX	85.00	85.00	85.00
42027	420270021	P103	1	30501404	NOX	85.00	85.00	85.00
42031	420310009	102	1	30501402	NOX	85.00	85.00	85.00
42031	420310009	S105A	1	30501402	NOX	85.00	85.00	85.00
42039	420390012	101	1	30501403	NOX	85.00	85.00	85.00
42039	420390012	102	1	30501403	NOX	85.00	85.00	85.00
42041	420410013	101	1	30501403	NOX	85.00	85.00	85.00
42041	420410013	102	1	30501403	NOX	85.00	85.00	85.00
42045	420450041	101	1	30501410	NOX	85.00	85.00	85.00
42051	420510020	101	1	30501402	NOX	85.00	85.00	85.00
42051	420510020	102	1	30501402	NOX	85.00	85.00	85.00
42065	420650003	110	1	30501402	NOX	85.00	85.00	85.00
42065	420650007	103	1	30501402	NOX	85.00	85.00	85.00
42065	420650007	104	1	30501402	NOX	85.00	85.00	85.00
42079	420790008	101	1	30501704	NOX	85.00	85.00	85.00
42079	420790008	102	1	30501704	NOX	85.00	85.00	85.00
42079	420790008	103	1	30501701	NOX	85.00	85.00	85.00
42079	420790018	101	1	30501402	NOX	85.00	85.00	85.00
42079	420790018	101	2	30501402	NOX	85.00	85.00	85.00
42079	420790018	102	1	30501402	NOX	85.00	85.00	85.00
42079	420790018	102	2	30501402	NOX	85.00	85.00	85.00
42079	420790018	103	1	30501402	NOX	85.00	85.00	85.00

FIPS	SITEID	EU ID	PROCESS ID	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
42083	420830002	101	1	30501402	NOX	85.00	85.00	85.00
42083	420830002	201	1	30501402	NOX	85.00	85.00	85.00
42083	420830006	101	1	30501402	NOX	85.00	85.00	85.00
42083	420830006	102	1	30501402	NOX	85.00	85.00	85.00
42083	420830006	103	1	30501402	NOX	85.00	85.00	85.00
42095	420950047	101A	3	30501701	NOX	85.00	85.00	85.00
42095	420950047	103A	3	30501701	NOX	85.00	85.00	85.00
42117	421170020	P109	1	30501402	NOX	85.00	85.00	85.00
42117	421170020	P124	1	30501404	NOX	85.00	85.00	85.00
42117	421170020	P127	1	30501408	NOX	85.00	85.00	85.00
42125	421250001	107	1	30501404	NOX	85.00	85.00	85.00
42125	421250001	107	3	30501404	NOX	85.00	85.00	85.00
42129	421290233	101	2	30501404	NOX	85.00	85.00	85.00
42129	421290233	102	2	30501404	NOX	85.00	85.00	85.00
42129	421290553	101	1	30501402	NOX	85.00	85.00	85.00
42133	421330066	104	3	30501414	NOX	85.00	85.00	85.00

Table E-2 NonEGU BOTW Control Factors for ICI Boilers

	Boiler Size Range (mmBtu/hour)						
	< 25	**25 to 50**	**50 to 100**	**100 to 250**	**>250**		
SCC	**CF0_25**	**CF25_50**	**CF50_100**	**CF100_250**	**CF250**	**SCC_L4**	**SCC_L3**
10200104	10	50	10	40	0	Traveling Grate (Overfeed) Stoker	Anthracite Coal
10200202	10	50	10	40	0	Pulverized Coal: Dry Bottom	Bituminous/Subbituminous Coal
10200203	10	50	10	40	0	Cyclone Furnace	Bituminous/Subbituminous Coal
10200204	10	50	10	40	0	Spreader Stoker	Bituminous/Subbituminous Coal
10200205	10	50	10	40	0	Overfeed Stoker	Bituminous/Subbituminous Coal
10200206	10	50	10	40	0	Underfeed Stoker	Bituminous/Subbituminous Coal
10200212	10	50	10	40	0	Pulverized Coal: Dry Bottom (Tangential)	Bituminous/Subbituminous Coal
10200222	10	50	10	40	0	Pulverized Coal: Dry Bottom (Subbituminous Coal)	Bituminous/Subbituminous Coal
10200401	10	50	10	40	0	Grade 6 Oil	Residual Oil
10200402	10	50	10	40	0	10-100 Million Btu/hr **	Residual Oil
10200403	10	50	10	40	0	< 10 Million Btu/hr **	Residual Oil
10200404	10	50	10	40	0	Grade 5 Oil	Residual Oil
10200405	10	50	10	40	0	Cogeneration	Residual Oil
10200501	10	50	10	40	0	Grades 1 and 2 Oil	Distillate Oil
10200502	10	50	10	40	0	10-100 Million Btu/hr **	Distillate Oil
10200503	10	50	10	40	0	< 10 Million Btu/hr **	Distillate Oil
10200504	10	50	10	40	0	Grade 4 Oil	Distillate Oil
10200505	10	50	10	40	0	Cogeneration	Distillate Oil
10200601	10	50	10	75	0	> 100 Million Btu/hr	Natural Gas
10200602	10	50	10	75	0	10-100 Million Btu/hr	Natural Gas
10200603	10	50	10	75	0	< 10 Million Btu/hr	Natural Gas
10200604	10	50	10	75	0	Cogeneration	Natural Gas
10200701	10	50	10	75	0	Petroleum Refinery Gas	Process Gas
10200704	10	50	10	75	0	Blast Furnace Gas	Process Gas
10200707	10	50	10	75	0	Coke Oven Gas	Process Gas
10200710	10	50	10	75	0	Cogeneration	Process Gas
10200799	10	50	10	75	0	Other: Specify in Comments	Process Gas
10200802	10	50	10	40	0	All Boiler Sizes	Petroleum Coke
10200901	10	10	10	10	10	Bark-fired Boiler	Wood/Bark Waste
10200902	10	10	10	10	10	Wood/Bark-fired Boiler	Wood/Bark Waste

	Boiler Size Range (mmBtu/hour)						
	< 25	**25 to 50**	**50 to 100**	**100 to 250**	**>250**		
SCC	**CF0_25**	**CF25_50**	**CF50_100**	**CF100_250**	**CF250**	**SCC_L4**	**SCC_L3**
10200903	10	10	10	10	10	Wood-fired Boiler - Wet Wood (>=20% moisture)	Wood/Bark Waste
10200904	10	10	10	10	10	Bark-fired Boiler (< 50,000 Lb Steam) **	Wood/Bark Waste
10200905	10	10	10	10	10	Wood/Bark-fired Boiler (< 50,000 Lb Steam) **	Wood/Bark Waste
10200906	10	10	10	10	10	Wood-fired Boiler (< 50,000 Lb Steam) **	Wood/Bark Waste
10200907	10	10	10	10	10	Wood Cogeneration	Wood/Bark Waste
10200908	10	10	10	10	10	Wood-fired Boiler - Dry Wood (<20% moisture)	Wood/Bark Waste
10201001	10	50	10	75	0	Butane	Liquified Petroleum Gas (LPG)
10201002	10	50	10	75	0	Propane	Liquified Petroleum Gas (LPG)
10201003	10	50	10	75	0	Butane/Propane Mixture: Specify Percent Butane in	Liquified Petroleum Gas (LPG)
10300101	10	50	10	40	0	Pulverized Coal	Anthracite Coal
10300102	10	50	10	40	0	Traveling Grate (Overfeed) Stoker	Anthracite Coal
10300103	10	50	10	40	0	Hand-fired	Anthracite Coal
10300203	10	50	10	40	0	Cyclone Furnace (Bituminous Coal)	Bituminous/Subbituminous Coal
10300206	10	50	10	40	0	Pulverized Coal: Dry Bottom (Bituminous Coal)	Bituminous/Subbituminous Coal
10300207	10	50	10	40	0	Overfeed Stoker (Bituminous Coal)	Bituminous/Subbituminous Coal
10300208	10	50	10	40	0	Underfeed Stoker (Bituminous Coal)	Bituminous/Subbituminous Coal
10300209	10	50	10	40	0	Spreader Stoker (Bituminous Coal)	Bituminous/Subbituminous Coal
10300225	10	50	10	40	0	Traveling Grate (Overfeed) Stoker (Subbituminous C	Bituminous/Subbituminous Coal
10300226	10	50	10	40	0	Pulverized Coal: Dry Bottom Tangential (Subbitumin	Bituminous/Subbituminous Coal
10300401	10	50	10	40	0	Grade 6 Oil	Residual Oil
10300402	10	50	10	40	0	10-100 Million Btu/hr **	Residual Oil
10300403	10	50	10	40	0	< 10 Million Btu/hr **	Residual Oil
10300404	10	50	10	40	0	Grade 5 Oil	Residual Oil
10300501	10	50	10	40	0	Grades 1 and 2 Oil	Distillate Oil
10300502	10	50	10	40	0	10-100 Million Btu/hr **	Distillate Oil
10300503	10	50	10	40	0	< 10 Million Btu/hr **	Distillate Oil
10300504	10	50	10	40	0	Grade 4 Oil	Distillate Oil
10300601	10	50	10	75	0	> 100 Million Btu/hr	Natural Gas
10300602	10	50	10	75	0	10-100 Million Btu/hr	Natural Gas
10300603	10	50	10	75	0	< 10 Million Btu/hr	Natural Gas
10300701	10	50	10	75	0	POTW Digester Gas-fired Boiler	Process Gas
10300799	10	50	10	75	0	Other Not Classified	Process Gas

	Boiler Size Range (mmBtu/hour)						
	< 25	**25 to 50**	**50 to 100**	**100 to 250**	**>250**		
SCC	**CF0_25**	**CF25_50**	**CF50_100**	**CF100_250**	**CF250**	**SCC_L4**	**SCC_L3**
10300811	10	50	10	75	0	Landfill Gas	Landfill Gas
10300901	10	10	10	10	0	Bark-fired Boiler	Wood/Bark Waste
10300902	10	10	10	10	0	Wood/Bark-fired Boiler	Wood/Bark Waste
10300903	10	10	10	10	0	Wood-fired Boiler - Wet Wood (>=20% moisture)	Wood/Bark Waste
10300908	10	10	10	10	0	Wood-fired Boiler - Dry Wood (<20% moisture)	Wood/Bark Waste
10301002	10	50	10	75	0	Propane	Liquified Petroleum Gas (LPG)
10301003	10	50	10	75	0	Butane/Propane Mixture: Specify Percent Butane in	Liquified Petroleum Gas (LPG)

Table E-3 Area Source BOTW Control Factors for Adhesives and Sealants Application, Asphalt Paving, Consumer Products, and Portable Fuel Containers

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
Control Measure: Adhesives and Sealants					
09	2440020000	VOC	64.40	64.40	64.40
10	2440020000	VOC	64.40	64.40	64.40
11	2440020000	VOC	64.40	64.40	64.40
23	2440020000	VOC	64.40	64.40	64.40
24	2440020000	VOC	64.40	64.40	64.40
25	2440020000	VOC	64.40	64.40	64.40
33	2440020000	VOC	64.40	64.40	64.40
34	2440020000	VOC	64.40	64.40	64.40
36	2440020000	VOC	64.40	64.40	64.40
42	2440020000	VOC	64.40	64.40	64.40
44	2440020000	VOC	64.40	64.40	64.40
Control Measure: Asphalt Paving					
09	2461022000	VOC	20.00	20.00	20.00
24	2461022000	VOC	20.00	20.00	20.00
25	2461022000	VOC	20.00	20.00	20.00
33	2461022000	VOC	20.00	20.00	20.00
34	2461022000	VOC	75.00	75.00	75.00
36	2461022000	VOC	20.00	20.00	20.00
42	2461022000	VOC	0.00	20.00	20.00
Control Measure: Consumer Products					
09	2465000000	VOC	2.00	2.00	2.00
10	2460100000	VOC	2.00	2.00	2.00
10	2460200000	VOC	2.00	2.00	2.00
10	2460400000	VOC	2.00	2.00	2.00
10	2460500000	VOC	2.00	2.00	2.00
10	2460600000	VOC	2.00	2.00	2.00
10	2460800000	VOC	2.00	2.00	2.00
10	2460900000	VOC	2.00	2.00	2.00
11	2460100000	VOC	2.00	2.00	2.00
11	2460200000	VOC	2.00	2.00	2.00
11	2460400000	VOC	2.00	2.00	2.00
11	2460500000	VOC	2.00	2.00	2.00
11	2460600000	VOC	2.00	2.00	2.00
11	2460800000	VOC	2.00	2.00	2.00
11	2460900000	VOC	2.00	2.00	2.00
23	2460100000	VOC	2.00	2.00	2.00
23	2460200000	VOC	2.00	2.00	2.00
23	2460400000	VOC	2.00	2.00	2.00
23	2460500000	VOC	2.00	2.00	2.00
23	2460600000	VOC	2.00	2.00	2.00
23	2460800000	VOC	2.00	2.00	2.00

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
23	2460900000	VOC	2.00	2.00	2.00
24	2465000000	VOC	2.00	2.00	2.00
25	2460000000	VOC	2.00	2.00	2.00
33	2460000000	VOC	2.00	2.00	2.00
34	2465000000	VOC	2.00	2.00	2.00
36	2460000000	VOC	2.00	2.00	2.00
42	2465000000	VOC	2.00	2.00	2.00
44	2460100000	VOC	2.00	2.00	2.00
44	2460200000	VOC	2.00	2.00	2.00
44	2460400000	VOC	2.00	2.00	2.00
44	2460500000	VOC	2.00	2.00	2.00
44	2460600000	VOC	2.00	2.00	2.00
44	2460800000	VOC	2.00	2.00	2.00
44	2460900000	VOC	2.00	2.00	2.00
Control Measure: Portable Fuel Containers					
09	2501060300	VOC	5.80	23.20	58.00
10	2501011010	VOC	5.80	23.20	58.00
10	2501011011	VOC	5.80	23.20	58.00
10	2501011012	VOC	5.80	23.20	58.00
10	2501011015	VOC	5.80	23.20	58.00
10	2501011016	VOC	5.80	23.20	58.00
10	2501012010	VOC	5.80	23.20	58.00
10	2501012011	VOC	5.80	23.20	58.00
10	2501012012	VOC	5.80	23.20	58.00
10	2501012015	VOC	5.80	23.20	58.00
10	2501012016	VOC	5.80	23.20	58.00
11	2501011011	VOC	5.80	23.20	58.00
11	2501011012	VOC	5.80	23.20	58.00
11	2501011016	VOC	5.80	23.20	58.00
11	2501012011	VOC	5.80	23.20	58.00
11	2501012012	VOC	5.80	23.20	58.00
11	2501012016	VOC	5.80	23.20	58.00
23	2501060300	VOC	5.80	23.20	58.00
24	2501011011	VOC	5.80	23.20	58.00
24	2501011012	VOC	5.80	23.20	58.00
24	2501011016	VOC	5.80	23.20	58.00
24	2501012011	VOC	5.80	23.20	58.00
24	2501012012	VOC	5.80	23.20	58.00
24	2501012016	VOC	5.80	23.20	58.00
25	2501011000	VOC	0.00	23.20	58.00
25	2501012000	VOC	0.00	23.20	58.00
33	2501060300	VOC	5.80	23.20	58.00
34	2501000120	VOC	5.80	23.20	58.00
36	2501011011	VOC	5.80	23.20	58.00
36	2501011012	VOC	5.80	23.20	58.00
36	2501011016	VOC	5.80	23.20	58.00
36	2501012011	VOC	5.80	23.20	58.00

FIPSST	SCC	PLLTCODE	CE_2009	CE_2012	CE_2018
36	2501012012	VOC	5.80	23.20	58.00
36	2501012016	VOC	5.80	23.20	58.00
42	2501060300	VOC	5.80	23.20	58.00
44	2501060300	VOC	5.80	23.20	58.00

Table E-4 Area Source BOTW Control Factors for ICI Boilers

SCC	Control Factor	SCC_L4	SCC_L3	SCC_L2
2102001000	18.9	Total: All Boiler Types	Anthracite Coal	Industrial
2102002000	18.9	Total: All Boiler Types	Bituminous/Subbituminous Coal	Industrial
2102004000	18.9	Total: Boilers and IC Engines	Distillate Oil	Industrial
2102005000	18.9	Total: All Boiler Types	Residual Oil	Industrial
2102006000	18.9	Total: Boilers and IC Engines	Natural Gas	Industrial
2102007000	18.9	Total: All Boiler Types	Liquified Petroleum Gas (LPG)	Industrial
2102008000	10.0	Total: All Boiler Types	Wood	Industrial
2102011000	10.0	Total: All Boiler Types	Kerosene	Industrial
2103001000	19.5	Total: All Boiler Types	Anthracite Coal	Commercial/Institutional
2103002000	19.5	Total: All Boiler Types	Bituminous/Subbituminous Coal	Commercial/Institutional
2103004000	19.5	Total: Boilers and IC Engines	Distillate Oil	Commercial/Institutional
2103004001	19.5		Distillate Oil	Commercial/Institutional
2103004002	19.5		Distillate Oil	Commercial/Institutional
2103005000	19.5	Total: All Boiler Types	Residual Oil	Commercial/Institutional
2103006000	19.5	Total: Boilers and IC Engines	Natural Gas	Commercial/Institutional
2103007000	19.5	Total: All Combustor Types	Liquified Petroleum Gas (LPG)	Commercial/Institutional
2103008000	10.0	Total: All Boiler Types	Wood	Commercial/Institutional
2103011000	10.0	Total: All Combustor Types	Kerosene	Commercial/Institutional

Consultation Appendix

Summary of Consultation between New York and the Other MANE-VU States

In early 2007, New York was provided by states in the MANE-VU region with the results of technical analyses that illustrated which states in the region have emissions that are reasonably anticipated to contribute to impairment in one or more of their Class I areas. These states sent a letter to these contributing states, inviting them to participate in consultations with New York 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 (State's) Class I areas. The consultation calls and meetings that New York engaged in with our counterparts in the MANE-VU region over these past few years served as a platform for comparing technical work and findings, discussing any adjustments that might be appropriate, and developing mutually beneficial solutions.

Representatives from the MANE-VU states have been meeting periodically since 2000 to review technical information and provide their perspectives and direction on the subsequent iterations of the analyses. The MANE-VU states established a more formal consultation process in 2007, beginning with an in-person meeting of the members in Washington, DC on March 1, 2007. At this meeting, the states received information on the requirements of the regional haze rule and how to define reasonable progress in 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. This was followed by a second in-person consultation in Providence, RI on June 7, 2007. This second meeting comprised a review of technical analyses completed to date, discussion of a resolution outlining the principles the Class I states would be following in their consultations with contributing states, and examination of a set of statements developed by the Class I states outlining their requests for control measures to be pursued by contributing states, both in the MANE-VU region and outside of it for the purpose of achieving reasonable progress in the MANE-VU Class I areas.

The MANE-VU Class I states made revisions to the resolution and statements as a result of the discussions that occurred at the June 7th meeting. The MANE-VU states then engaged in another consultation via conference call on June 20, 2007 to review the revised documents and vote on them. All member states on the consultation call voted to accept the resolution and statements, with the exception of New York and Vermont, who were unable to participate on the call. The MANE-VU executive staff followed up with both New York and Vermont by phone and email, and received their concurrence on the documents as well. Via the 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 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 (500ppm) 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 (SO2) 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
- Continued evaluation of other control measures including energy efficiency, alternative clean fuels, and other measures to reduce SO2 and nitrogen oxide (NOx) emissions from all coal-burning facilities by 2018 and new source performance standards for wood combustion. These measures and other measures identified will be evaluated during the consultation process to determine if they are reasonable and cost-effective.

In addition, the long-term strategy accepted by the MANE-VU states to reduce and prevent regional haze allows each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO2 controls.

Through the MANE-VU states' acceptance of the emission management strategies outlined in the statements on the June 20th call, they confirmed the set of actions the MANE-VU states will pursue in their state implementation plans (SIPs) to provide reasonable progress toward improved visibility by 2018, the first milestone in meeting the long-term regional haze goals for each Class I area. The MANE-VU Air Directors also consulted on issues concerning the emission management strategies outlined in the statements on three subsequent conference calls. During the September 26, 2007 call, participants discussed how to interpret the emission management strategies in the statements for purposes of estimating visibility impacts via air quality modeling. On February 28, 2008 the MANE-VU states received the results of the final 2018 modeling runs. Finally, on the March 21, 2008 call the states discussed the process for establishing reasonable progress goals for the MANE-VU Class I areas.

Summaries of the individual meetings and calls referenced above follow, along with copies of the final resolution and statements accepted by the MANE-VU member states.

Listing of consultation summary documentation:

1. Intra-MANE-VU Consultation Meeting Summary, March, 1, 2007, Washington, DC
2. Intra-MANE-VU Consultation Meeting Summary, June 7, 2007, Washington, DC
3. Intra-MANE-VU Consultation Conference Call Summary, June 20, 2007
4. Intra-MANE-VU Consultation Conference Call Summary, MANE-VU Air Directors, March 31, 2008
5. Resolution of the Commissioners of States with Mandatory Class I Federal Areas Within the Mid-Atlantic Northeast Visibility Union (MANE-VU) Regarding Principles for Implementing the Regional Haze Rule, adopted June 20, 2007
6. Statement 1: Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Course of Action Within MANE-VU Toward Assuring Reasonable Progress, adopted June 20, 2007
7. Statement 2: 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, adopted June 20, 2007
8. Statement 3: Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Request for a Course of Action by the U.S. Environmental Protection Agency (EPA) Toward Assuring Reasonable Progress, adopted June 20, 2007
9. Attachment to Statements 1 and 2: List of 167 EGU stacks, dated June 20, 2007

Intra-MANE-VU Consultation Meeting Summary
March 1, 2007
Washington DC

Introduction

The Mid-Atlantic/Northeast Visibility Union (MANE-VU) held an in-person consultation meeting of the region's states on March 1, 2007 in Washington DC. The purpose of the consultation meeting was to fulfill the requirements of 40 CFR 51.308(d)(1)(B)(iv) and (3)(i) for Class I states to consult with contributing states on developing reasonable progress goals for the region's seven mandatory federal Class I areas, and for all contributing states to consult on the development of coordinated emission management strategies. All MANE-VU states were invited to participate along with the region's Federal Land Managers (FLMs) from the National Park Service, Fish & Wildlife Service, and Forest Service, and the Environmental Protection Agency (EPA) regional representatives from Regions I, II, and III.

Topics discussed included:

1) An overview of the regional haze program's goals and requirements;
2) A review of the uniform progress glidepaths and anticipated status of visibility impairment in 2018 in the seven MANE-VU mandatory federal Class I areas; and
3) A review of an analysis based on the Clean Air Act's statutory factors of what controls may be considered reasonable; and 4) Discussions of reasonable control options by source sector.

Key Outcomes of the Consultation

- As an overriding principle, MANE-VU looks for equivalent reductions, not equal reductions across source categories.
- A low-sulfur fuel oil strategy is viable as a MANE-VU 2018 control measure, at a 500 ppm sulfur limit in the near-term, and a 15 ppm goal for distillate in 2018.
- Sulfur limits on #4 and #6 fuel oil require more analysis, and oil-fired EGUs with scrubbers will need flexibility.
- The ICI boiler sector needs further analysis as to what controls may be reasonable, especially from small and medium-sized boilers.
- If it is reasonable for MANE-VU to achieve a 40% sulfur reduction in the non-EGU sector, it may also be reasonable that contributing states in other RPOs could find equivalent reasonable reductions.
- There was no real consensus on controls on residential wood / open burning as a regional strategy, as what can be achieved in these sectors varies widely from state to state.
- MANE-VU Class I states will conduct a series of separate phone calls to develop a proposal for moving forward on consultations and developing reasonable control options.
- The MANE-VU states agreed to keep working towards implementing reasonable regional controls, which would be discussed at the next MANE-VU consultation meeting in June 2007.

Attendees

States and Tribes:
Maine (Class I state) – David Littell, Jeff Crawford
New Hampshire (Class I state) – Jeff Underhill
New Jersey (Class I state) – Lisa Jackson, Nancy Wittenberg, Chris Salmi
Vermont (Class I state) – Justin Johnson, Dick Valentinetti, Paul Wishinski
Connecticut – Anne Gobin
Delaware – Ali Mirzakhalili
District of Columbia – Diedre Elvis-Peterson, Abraham Hagos
Maryland – Tad Aburn
Massachusetts – Arleen O'Donnell, Barbara Kwetz
Pennsylvania – Tom Fidler, Joyce Epps, Wick Havens
New York – Dave Shaw, Rob Sliwinski

Federal Land Management Agencies and EPA Regional Offices:
National Park Service – Bruce Polkowsky, John Bunyak
Forest Service – Anne Mebane, Anne Acheson, Andrea Stacey
Fish and Wildlife Service – Sandra Silva, Tim Allen
EPA Region I – Anne Arnold
EPA Region III – Makeba Morris, Neil Bigioni

Welcome and Introductory Remarks

David Littell, MANE-VU Vice-Chair and Commissioner of Maine's Department of Environmental Protection, opened the consultation with a welcome and introductions around the room. Mr. Littell followed with a presentation entitled "Bringing Clear Views to Acadia National Park and Other Class I Areas." Acadia National Park is one of three mandatory Class I areas in Maine while New Hampshire has two, and Vermont and New Jersey each have one. Mr. Littell noted that annual visitation at Acadia is over 2 million visits a year leading to visitor spending of more than $127 million in 2005, and surveys indicate that a clear vista is a strong factor in a visitor's positive experience at the park.

Mr. Littell then provided an overview of the goals for today's consultation, including:

- Review requirements, resources and critical timing issues to ensure all share a common understanding;
- Discuss options for control measures to identify what is reasonable in MANE-VU;
- Identify impediments to implementing control measures and discuss how to address them;
- Identify links between haze, PM, and ozone strategies that help define what's reasonable;

- Define reasonable progress for MANE-VU Class I Areas in terms of control measure options; and
- Summarize points of agreement and identify issues for follow-up consultation.

Overview of MANE-VU Consultation

Anna Garcia, MANE-VU Deputy Director, followed with a presentation entitled “Timing, Contribution, and Consultation.” Noting that multiple methods show consistent conclusions about which states are top contributors and that a single MANE-VU consulting group offers the best opportunity to engage contributing states in a meaningful consultation process, Ms. Garcia emphasized that the MANE-VU states need to make sure we know what we are asking of the states within MANE-VU before consulting with contributing states outside of MANE-VU. Today’s consultation is the first formal intra-MANE-VU consultation being held to develop MANE-VU’s “clean hands” position and to start the process of determining reasonable control measures by MANE-VU states for the December 2007 Regional Haze State Implementation Plan (SIP) submissions.

MANE-VU Regional Haze Goals

Paul Wishinski from Vermont’s Department of Environmental Conservation followed with a presentation entitled “Overview of Program Requirements for the Regional Haze Rule.” Under the regional haze regulations, both the reasonable progress goals to be set by the Class I states and the long-term coordinated emissions strategies to meet the reasonable progress goals require consultations with contributing states and the Federal Land Managers (FLMs). Mr. Wishinski concluded, as did Ms. Garcia before, that the key next step is for the MANE-VU states to agree on what they believe are reasonable control measures for visibility improvement at the MANE-VU Class I areas.

Jeff Underhill from New Hampshire’s Department of Environmental Services followed with a presentation entitled “Status of Visibility at MANE-VU Class I sites and Modeling for the Regional Haze Rule.” Based on modeling results, Mr. Underhill concludes that all of MANE-VU’s seven mandatory Class I areas will likely be below the uniform progress line in 2018 with “on-the-books” controls plus 500 ppm maximum sulfur limit for #2 distillate, except in Delaware and Vermont. However, more progress can be made through additional reasonable measures, and the Regional Haze Rule requires us to consider these measures via the consultation process with contributing states.

Developing Reasonable Progress for MANE-VU Class I Areas

Art Werner of MACTEC Federal Programs, Inc., MANE-VU’s contractor for the four-factor reasonable progress project, followed with a presentation on the preliminary results of that project. Mr. Werner reviewed the four factors that need to be analyzed to determine which emission control measures are needed to make reasonable progress in improving visibility: 1) the costs of compliance, 2) the time necessary for compliance, 3) energy an nonair quality environmental impacts of compliance, and 4) the remaining useful life of any source subject to such requirements. Mr. Werner also presented a preliminary marginal cost figure of $1,390/ton (1999$) of SO2 in 2018 from a recent MANE-VU-sponsored IPM run for a “CAIR Plus” policy. The final report due in May will provide a methodology for addressing reasonable progress and inform the MANE-VU states on control measure costs for both priority source categories and selected individual sources for upcoming consultations on setting the reasonable progress goals for the MANE-VU mandatory Class I areas.

Assessing Control Options

The final presentation by Chris Salmi with New Jersey's Department of Environmental Protection entitled "Reasonable Measure Opportunities" emphasized that the MANE-VU Class I states intend to focus their reduction efforts for the 2018 milestone on sulfur dioxide reductions since they cause, on average, nearly 80% of the visibility impairment on the 20% worst days. Mr. Salmi presented recent control measure analyses showing that MANE-VU sources can reasonably achieve over 200,000 tons of SO2 reductions in 2018 from non-EGU control measures, primarily from ICI coal and oil-fired sources, a low-sulfur distillate strategy, and controls on Best Available Retrofit Technology (BART) sources. Mr. Salmi concluded his presentation by posing two questions for the members:

1) What measures does MANE-VU consider reasonable for 2018?, and
2) What measures do we ask others to implement?

The questions began a roundtable discussion initiated by Ms. Garcia's intentionally broad question to the members asking what is reasonable.

Summary of Discussion

NESCAUM suggested, and New Hampshire agreed that as an overriding principle what MANE-VU is looking for is equivalent reductions, not equal reductions across source categories. The discussion segued to what MANE-VU can reasonably accomplish for a low-sulfur fuel oil strategy. The members agreed that this is a prime example of a source category where MANE-VU can make reasonable reductions due the widespread use of distillate for residential and commercial heating. Other states primarily outside of MANE-VU do not have a similar reliance on fuel oil for heating, so they could make equivalent reasonable reductions from other source categories to match MANE-VU's heating oil sulfur reductions.

Further discussion continued with respect to two potentially reasonable fuel-oil strategies for the MANE-VU region, dubbed S1 and S2:

- § S1 is less stringent and envisions a 75% reduction in sulfur content to 500 ppm by 2018 for home heating / distillate, and 50% reductions in sulfur content for #4 and #6 fuel oils.
- § S2 envisions a 99.25% reduction in sulfur content to 15 ppm by 2018 for home heating / distillate, and the same 50% reductions for #4 and #6 as in S1.

New Hampshire suggested the need to move carefully due to the concerns about price and supply issues. Vermont countered that there is a 10-year timeframe to accomplish a low-sulfur fuel oil strategy. Pennsylvania suggested that a 500 ppm strategy is reasonable, but timing is important. Vermont added that the Northeast states have been discussing low-sulfur fuel oil strategies for ten years already, and that two or three states such as New York, New Jersey, and Connecticut need to go first and pass regulations to catalyze regional negotiations with industry. New Jersey noted that New Jersey has started their rulemaking process on low-sulfur fuel oil; New York added that New York has started their rulemaking process for 500 ppm for distillate by 2018. Connecticut said that Connecticut's fuel standards are set by statute, and the statute precludes Connecticut from lowering its fuel-oil standards until neighboring states Massachusetts and Rhode Island do so as well, presumably for regional supply reasons.

Continuing the low-sulfur fuel oil discussion, Pennsylvania asked if EPA has been approached on a national low-sulfur fuel oil strategy. New Jersey replied that EPA is not focusing on this area, leaving it to the states. NESCAUM added that the industry believes that part of the deal with EPA for accomplishing the 15 ppm on-road ultra low-sulfur diesel (ULSD) standard is that there will be no more sulfur reductions expected. MANE-VU noted that in recent discussions, the industry suggested it was possible to achieve a 15 ppm sulfur level for distillate within a 2014 timeframe. Massachusetts said that it may be difficult for Massachusetts to commit to a 15 ppm sulfur level in distillate by 2018, noting, however, that the positive co-benefits of greater furnace efficiency and therefore lower GHG emissions might help in instituting a 15 ppm sulfur level in distillate regulation. New Jersey emphasized that we have a decade to accomplish a 15 ppm sulfur standard for distillate.

MANE-VU asked the group about what might work in terms of lower sulfur limits in #4 and #6 fuel oils. Pennsylvania said that Pennsylvania has various sulfur limits and they would need more time to analyze such limits. New Jersey noted that these low-sulfur fuels are already available as some New Jersey counties are already below 5000 ppm sulfur. Maine questioned what limits on #6 fuel oil would mean for those oil-fired EGUs that have scrubbers.

MANE-VU wrapped up the low-sulfur fuel-oil discussion asking the group if the S1 strategy was viable as a MANE-VU 2018 region haze control measure. The consensus was that a 500 ppm sulfur limit “near-term” and a 15 ppm “goal” for distillate in 2018 is viable. For #4 / #6 sulfur limits, the consensus was that more work needs to be done, and that flexibility should be provided to states that have scrubbers on their oil-fired EGUs.

The consultation moved on to sulfur reductions from the coal-fired ICI (Industrial, Institutional, and Commercial) sector and whether MANE-VU can include such reductions in a non-EGU strategy bundle at this time. Pennsylvania suggested that controls for small-to-medium size boilers (<100 MM Btu / hour heat input) may not be cost-effective, adding that a 50% reduction in sulfur emissions from coal-fired ICI sources may overestimate what can realistically be achieved. New Hampshire suggested that recent analysis by New Hampshire staff on installation costs should be considered. Maine added that this sector may be a viable source for other RPO states to achieve reasonable sulfur reductions from their non-EGU sectors that are equivalent to the 40% sulfur reductions expected from non-EGU sources within MANE-VU due to the low-sulfur fuel oil strategy.

The consensus concerning sulfur reductions from the coal-fired ICI sector was that there is a need for more analysis to determine what is reasonable to obtain sulfur reductions from small and medium-sized coal-fired boilers. There was also consensus that if MANE-VU achieves overall reasonable sulfur reductions in the 40% range from the non-EGU sector, then other RPOs could find equivalent reasonable reductions.

Discussions moved on to other potential regional haze control measures within MANE-VU. For lime and cement kilns, both Pennsylvania and New York agreed that there is wide variability in these sources. Pennsylvania suggested that lime kiln controls are not cost-effective, and that an EPA global settlement on cement kilns was coming soon anyway. New York added that they will be regulating its three cement kilns as BART sources.

For the residential wood combustion / open burning source category, there was general consensus on including outdoor wood boilers in this category. New Jersey encouraged greater use wood stove changeout programs. New Hampshire replied that what can be done on wood combustion varies from state to state, and, for example, in New Hampshire new wood stove standards would be acceptable, but not changeout programs. New York added that open burning bans are unenforceable, especially in rural areas. There was little consensus on control measures in this source category, especially considering that the primary pollutants of concern are organic carbon and direct particulate matter, and not sulfur which is the primary regional haze pollutant within MANE-VU for the first planning milestone in 2018.

The Intra-MANE-VU Consultation Meeting adjourned.

Intra-MANE-VU Consultation Meeting
June 7, 2007
Providence, Rhode Island

Introduction

The Mid-Atlantic/Northeast Visibility Union (MANE-VU) held an in-person consultation meeting of the region's states on June 7, 2007 in Washington DC. The purpose of the consultation meeting was to fulfill the requirements of 40 CFR 51.308(d)(1)(B)(iv) and (3)(i) for Class I states to consult with contributing states on developing reasonable progress goals for the region's seven mandatory federal Class I areas, and for all contributing states to consult on the development of coordinated emission management strategies. All MANE-VU states were invited to participate along with the region's Federal Land Managers (FLMs) from the National Park Service, Fish & Wildlife Service, and Forest Service, and the Environmental Protection Agency (EPA) regional representatives from Regions I, II, and III.

Topics discussed included: 1) the process for setting reasonable progress goals by the MANE-VU Class I states; 2) an approach for intra-MANE-VU consultation including control strategy development within MANE-VU for setting the reasonable progress goals; 3) an approach for consulting with states outside of MANE-VU on the reasonable progress goals to be established by the MANE-VU Class I states; and 4) the next steps in the consultation process.

Key Outcomes of the Consultation

- All of the MANE-VU states agreed that a resolution setting out the principles by which the Class I states will implement the regional haze rule should go the MANE-VU Board for approval, although the document was to be signed only by the MANE-VU Class I states.
- Two separate draft statements on courses of action by states within and outside MANE-VU for assuring progress towards the MANE-VU Class I States' reasonable progress goals were tabled until a corrected list of 167 EGU stacks impacting visibility in the MANE-VU Class I areas could be generated. The MANE-VU states agreed that they would vote by conference call once the corrected 167 EGU stack list became available.

Attendees

States:
Maine (Class 1 state) – David Littell
New Hampshire (Class 1 state) – Bob Scott, Jeff Underhill
Vermont (Class 1 state) – Justin Johnson, Dick Valentinetti
New Jersey (Class 1 state) – Lisa Jackson, Nancy Wittenberg, Chris Salmi

Connecticut – Dave Wackter
Delaware – Ali Mirzakalili
District of Columbia – Cecily Beall
Massachusetts – Arleen O'Donnell, Barbara Kwetz
Maryland – Tad Aburn
New York – Dave Shaw
Pennsylvania – Tom Fidler, Joyce Epps, Wick Havens

Rhode Island – Michael Sullivan, Steve Majkut

Federal Land Management Agencies and EPA Regional Offices:
National Park Service – Bruce Polkowsky (in person), Holly Salazar (on phone)
Fish & Wildlife Service – Tim Allen (on phone)
Forest Service – Ann Mebane, Ann Acheson (on phone)
EPA Region III (on phone)

Welcome and Introductions

David Littell, MANE-VU Vice-Chair and Commissioner of Maine's Department of Environmental Protection, opened the consultation with a welcome and introductions around the room, including those on the phone. Anna Garcia, MANE-VU Deputy Director, followed with a brief outline of the goals for the consultation, including an update on recent technical work and discussions of the proposed MANE-VU Class I states resolution on consultation principles, a proposed statement on control measures within the MANE-VU region for achieving reasonable progress goals, and a proposed statement on controls outside of the MANE-VU region for achieving reasonable progress goals.

Status of Technical and Policy Work Issues

Gary Kleiman, NESCAUM, led this session with an update of the recent technical work, including preliminary modeling results. All seven of the MANE-VU Class I areas will be below the uniform rate of progress in 2018 according to preliminary modeling results. Tad Aburn, Maryland, asked the Federal land Managers (FLMs) if the MANE-VU technical approach is satisfactory. Bruce Polkowsky, National Park Service, replied that the other eastern RPOs are doing similar work and achieving better than uniform progress but have different approaches to reasonable progress. Tim Allen, Fish and Wildlife Service, commented that MANE-VU is not taking as much of a chemistry-intensive approach as other RPOs, and MANE-VU will likely need to address nitrates and organics in the next regional haze planning phase after 2018. Mr. Allen added that he is very supportive of obtaining as many reductions as possible now as they will only be more difficult to obtain later.

Chris Salmi, New Jersey Department of Environmental Protection, followed with a presentation on MANE-VU's approach to fulfilling the regional haze rule's reasonable progress requirement. The statutory four-factor analysis for control strategies for visibility-impairing source sectors provides the central focus for the Class I states' determination of what is reasonable. Finally, Anna Garcia ended the session with a brief presentation on the process by which MANE-VU chose the regional source sectors that were included in the four-factor analysis.

Roundtable Discussions

The MANE-VU states began their consultation with a roundtable discussion of the draft resolution by the MANE-VU Class I states on principles for implementing the regional haze rule, including the requirement for consulting with contributing states on reasonable progress. After minor wording changes, the states then agreed to seek Board approval although the resolution would be signed only by the MANE-VU Class I states.

Roundtable discussions ensued on the two proposed statements, one on control strategies within the MANE-VU states for assuring reasonable progress, and the other for states outside MANE-VU. When it became clear that more work needed to be done so all states were comfortable with the final list of 167 EGU stacks having the greatest visibility impact on the MANE-VU Class I areas, the states agreed to postpone voting on the statements until a later date by conference call.

A final discussion on a draft statement on requesting further action by the U.S. Environmental Protection Agency (EPA) on tightening the CAIR program for assuring reasonable progress also occurred. The states also agreed to table a vote on this statement until a conference call.

Consultation Next Steps

A brief discussion on next consultation steps, especially with the Regional Planning Organizations outside of MANE-VU also occurred. Those steps include:

- Consulting within and outside MANE-VU about which control strategies are reasonable;
- Deciding how to include the strategies in the final statements in modeling;
- Determining goals based on final modeling;
- Pursuing the adoption of enforceable emissions limits & compliance schedules; and
- Evaluating progress in 5 years.

Intra- MANE-VU Consultation Conference Call SummaryJune 20, 2007

IntroductionOn June 20, 2007 the MANE-VU Commissioners and Air Directors participated on a conference call to continue consultation discussions on emission management strategies for the region to pursue to achieve reasonable progress toward natural conditions in the region's Class I areas. The MANE-VU state Members completed their review of a resolution and three statements proposed by the Class I states to the larger MANE-VU membership, and voted to accept these documents and confirm the set of actions the MANE-VU states will pursue in their state implementation plans (SIPs) to provide reasonable progress toward improved visibility by 2018, the first milestone in meeting the Class I areas' long-term regional haze goals.

Attendees
States, Tribes and MSOs:
Maine (Class 1 state) – David Littell, Jeff Crawford

New Hampshire (Class 1 state) – Jeff Underhill, Andy Bodnarik
New Jersey (Class 1 state) – Chris Salmi
Connecticut – Anne Gobin
Delaware – Ali Mirzakalili
District of Columbia – Cecily Beall
Massachusetts – Barbara Kwetz
Maryland – Tad Aburn, Andy Hiltebridle
New York – Dave Shaw
Pennsylvania – Tom Fidler, Joyce Epps, Wick Havens
Penobscot Tribe – John Banks, Bill Thompson
Rhode Island – Steve Majkut
NESCAUM – Arthur Marin, Gary Kleiman

Consultation Discussions The MANE-VU states voted on and passed three statements, which are attached to this summary, with some minor changes. The three statements are entitled as follows:

1. Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Course of Action Within MANE-VU Toward Assuring Reasonable Progress;

2. 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; and
3. Statement of the Mid-Atlantic / Northeast Visibility Union (MANE-VU) Concerning a Request for a Course of Action by the U.S. Environmental Protection Agency (EPA) Toward Assuring Reasonable Progress.

The final versions of the statements which were accepted via the vote reflect the following changes:

- agreement on the list of EGU stacks, which is attached to both Statement 1 and 2, and revising the table to remove columns listing plant type, SO2 tons per year and rank, and changing the bottom notes accordingly (see explanation below);
- removal of the phrase "top 100" from the 4th action bullet on Statement 1 and the 2nd action bullet on Statement 2 (regarding 90% reduction from EGUs);

- correction of the date for 500 ppm low sulfur fuel oil to "by no later than 2012" (I made the error of changing that date to "2014" in translating the Consultation comments - it should be 2012 as for the other inner zone fuel requirements);
- revision of the last paragraph in Statement 3 to delete "beyond 2018 CAIR levels" and replace it with "by no later than 2018"; and
- a change in the signature line on all three statements to "Adopted by the MANE-VU States and Tribes on (date)."

In addition, the members agreed to keep the columns that were deleted from the abbreviated “167 stacks” table as part of the larger spreadsheet of the 167 stacks that MARAMA produced and t make that document part of a technical support document to Statements 1 and 2. The columns were deleted to keep the table simple and to reduce confusion about tons per year information used in the modeling vs. tons per year information in the Acid Rain Database, in which there are some differences. Attachment 1 to the Statements refers to the 2002 tons per year information from the MANE-VU Contribution Assessment at the bottom of the table. The MANE-VU states also confirmed that, if it is infeasible for the oil/gas units that are in New Hampshire and Maine to meet the 90% reduction for EGUs, meeting the low sulfur fuel oil requirements would be sufficient. In addition, the MANE-VU states will also credit early state actions (within a few years prior to 2002) toward the 90% target of reducing emissions from EGUs on the “167 stack” list. The group also decided that the technical support document for the statements and the consultation summaries would be circulated to the MANE-VU states for their review and comment, and to get any further corrections to the more comprehensive table of 167 stacks (some states had changes to the plant types on the list).Voting on the StatementsAt the end of the call the states voted on whether they would accept each of the statement. For Statement 1, New Jersey moved that the statement be put up for a vote and Pennsylvania seconded the motion. All MANE-VU states on the call voted to accept Statement 1. On Statement 2, the Penobscot Tribe moved that it be considered for a vote and Massachusetts seconded the motion. Once again, all MANE-VU states on the call voted to accept Statement 2. Finally, for Statement 3, the Penobscot Tribe moved that it be considered for a vote and New Jersey seconded the motion. All MANE-VU states on the call voted to accept Statement 3. New York and Vermont were unable to participate on the consultation conference call, so to ensure that all the MANE-VU member states are in agreement on these actions, the MANE-VU executive staff proposed to contact each state individual by phone and email to get their response to the vote on the statements. Within one day of the consultation conference call, the MANE-VU executive staff briefed New York and Vermont by phone and email and received their confirmation that they accepted all three statements as revised on the call.

Intra-MANE-VU Consultation – March 31, 2008 – MANE-VU Air Directors' Call

States Attending the Consultation

Maine (Class I state) – Jeff Crawford
New Hampshire (Class I state) – Jeff Underhill, Andy Bodnarik
New Jersey (Class I state) – Chris Salmi, Stella Oluwasuen-Apo, Peg Gardner
Connecticut – Dave Wackter
Delaware – Jack Sipple
District of Columbia – Cecily Beall
Maryland – Roger Thunell, Brian Hug
Massachusetts – Glenn KeithNew York – Gopal Sistla, Rob Sliwinski
Pennsylvania – Joyce Epps

Representatives of MANE-VU member states met via conference call on March 31, 2008. During the call, NESCAUM modeling assumptions and results were reviewed, and the three Class I states present (Maine, New Hampshire, and New Jersey) confirmed that they would be relying on the results of that modeling to set their reasonable progress targets. The targets based on the modeling were included in the MANE-VU SIP Template draft that is posted on the MARAMA web site and will be sent to EPA for review. (Note: sent on 4/2/08)
Ms. Garcia agreed to share the results of the MANE-VU modeling with Virginia and West Virginia before the Stakeholder meeting on Friday, April 4.

Maine, New Hampshire, Vermont, and Massachusetts had met with oil companies and distributors concerning the MANE-VU low sulfur oil strategy. Stakeholders had expressed some concern about the 0.5% limit for residual oil, but states wanted to gather more information before deciding whether to make any changes in the MANE-VU strategy.

Participating states reviewed choices concerning the Long Term Strategy section of the SIP Template, and it was agreed that a document describing those choices would be revised and discussed further with EPA and FLM agency representatives. Individual MANE-VU states might make different choices with respect to language in their SIPs, and some gave indications of their preferences.

Mid-Atlantic/Northeast Visibility Union
MANE-VU

Technical Support Document on Measures to Mitigate the Visibility Impacts of Construction Activities in the MANE-VU Region

Draft: September 1, 2006

1. Introduction

Each state must develop a long-term (10-15 years) strategy for making reasonable progress towards the national goal stated in 40 CFR section 51.300(a), “preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution.” States are required to develop long-term strategies for each mandatory Class I Federal area located within the state and each mandatory Class I Federal area located outside the state that may be affected by sources within the state. According to 40CFR section 51.308(d)(3)(v)(B), states must consider “measures to mitigate the impacts of construction activities” in developing its long-term strategies for regional haze.

The purpose of this technical support document is to assist States in considering measures in the MANE-VU Region to mitigate the impacts of construction activities. This document provides background information on the air quality impacts of construction activities, presents relevant emissions inventory and contribution assessment results, describes potential control measures, and summarizes state regulations currently in place in the MANE-VU Region.

2. Air Quality Impacts of Dust and Diesel Usage from Construction Activities

According to the EPA (www.epa.gov/ttn/chief/ap42/ch13), construction activities may have a significant, albeit temporary, impact on local air quality. Construction activities are sources of fugitive dust and air pollutants from the use of diesel powered equipment.

There are two primary mechanisms of generating fugitive dust, pulverization of surface materials by mechanical equipment and entrainment of dust by wind. Large dust particles typically settle out near the source, creating potential nuisance issues. Particles larger than 100µm generally settle out within six to nine meters from the source while particles between 20 and 100µm typically fall out within a few hundred feet of the source. Smaller particles, especially particles smaller than 10µm (PM_{10}) can persist in the atmosphere, possibly contributing to diminished visibility.

Construction activities that can contribute substantial dust emissions include land clearing, drilling and blasting, ground excavation, hauling dirt, and the construction of roads and buildings. Equipment traffic over temporary roads at construction sites can make up a large portion of the emissions. The use of diesel fuel in construction equipment causes the emission of Carbon Monoxide (CO), Volatile Organic Compounds (VOCs), Nitrogen Oxides (NOx), and Particulate Matter (PM) into the air. These pollutants may contribute to reduced visibility. Construction activities that contribute to the release of the above mentioned pollutants include, idling, the use of high sulfur fuel and diesel, the lack of exhaust controls, and the use older vehicles that are not properly maintained.

In contrast to other fugitive dust sources, such as dust generated from unpaved roads and agricultural tilling practices, construction activities are temporary with a definable beginning and end, and vary significantly over different phases of the construction project. Dust and diesel emissions from construction sites vary daily depending on the level of activity, specific operations, specific machinery used, and meteorological conditions. Other factors that play a role in dust emissions include the silt (particles smaller than 75μm in diameter) content of the soil, soil moisture, the speed and weight of construction equipment. Dust emissions are positively correlated with silt content and the weight of vehicles and negatively correlated with soil moisture content.

3. Relevant Emissions Inventory Results

The Mid-Atlantic Regional Air Management Association (MARAMA), on behalf of MANE-VU, developed a “Fugitive Dust Construction Area Source Category Calculation Methodology Sheet,” for use by MANE-VU States. The calculation methodology sheet describes how States may calculate emissions of particulate matter from residential, non-residential, and road construction activities. The calculation methodology sheet, which was most recently updated in December 2004, is available online at http://www.marama.org/visibility/Calculation_Sheets/FugitiveDustConstruction122004.doc.

States submitted $PM_{2.5}$ and PM_{10} data on emissions from construction activities of various types, which were compiled in the MANE-VU 2002 Inventory. Under contract by MARAMA, E.H. Pechan and Associates summed the $PM_{2.5}$ and PM_{10} data for the categories of residential construction, road construction, and industrial/commercial/institutional construction. These category values were added together to determine the Total Construction Emissions for each state, shown in Tables 1 and 2 and Total Off-Highway Diesel Emissions for each state shown in Tables 3 and 4. Each table below shows the Total Emissions of $PM_{2.5}$ and PM_{10} from all sources of pollution, including point source, area, non-road, and on-road in units of tons per year. In the case of non-diesel construction activities, the percentages of construction emissions from area sources and the percentage of construction emissions from all sources were calculated and shown in Tables 1 and 2 for $PM_{2.5}$ and PM_{10} respectively. In the case of diesel emissions the total emissions from all sources are followed by the Total Nonroad Source Emissions, and then the Total Off-Highway Diesel Emissions, the Construction Emissions as a percent of Nonroad Inventory and finally the Construction Emissions as a percent of Total Inventory were calculated and shown in Tables 3 and 4 for $PM_{2.5}$ and PM_{10} respectively.

Table 1: 2002 $PM_{2.5}$ emissions from construction activities (Data Source: 2002 MANE-VU Modeling Inventory, Version 3.0)

State	Total Emissions from all sources of $PM_{2.5}$ (tons/year)	Total Area Source Emissions $PM_{2.5}$ (tons/year)[1]	Total Construction Emissions $PM_{2.5}$ (tons/year)	Construction Emissions as a % of Area Sources Emissions	Construction Emissions as a % of Total Inventory
Connecticut	18365.9	14247.3	932.7	6.5	5.1
Delaware	8210.2	3203.6	268.6	8.4	3.3
District of Columbia	1388.8	804.8	156.9	19.5	11.3
Maine	40824.9	32773.7	373.4	1.1	0.9
Maryland	38929.7	27318.3	2835.1	10.4	7.3
Massachusetts	51864.4	42067.5	2530.8	6.0	4.9
New Hampshire	21996.8	17532.0	352.9	2.0	1.6
New Jersey	31595.3	19349.6	88.3	0.5	0.3
New York	108952.6	87154.2	7039.8	8.1	6.5
Pennsylvania	108811.6	74924.7	7694.7	10.3	7.1
Rhode Island	2901.3	2064.2	301.8	14.6	10.4
Vermont	12300.3	11064.5	264.5	2.4	2.2
MANE-VU	446142.0	332504.5	22839.4	7.5	5.1

[1] SCC 23110xxxx

Table 2: 2002 PM_{10} emissions from construction activities (Data Source: 2002 MANE-VU Modeling Inventory, version 3.0)

State	Total Emissions from all sources of PM_{10} (tons/year)	Total Area Source Emissions PM_{10} (tons/year)[1]	Total Construction Emissions PM_{10} (tons/year)	Construction Emissions as a % of Area Source Emissions	Construction Emissions as a % of Total Inventory
Connecticut	53430.1	48280.7	9327.4	19.3	17.5
Delaware	18857.7	13038.6	2712.1	20.8	14.4
District of Columbia	3962.6	3269.2	784.3	24.0	19.8
Maine	178918.5	168953.4	3733.8	2.2	2.1
Maryland	112193.1	95060.2	28350.7	29.8	25.3
Massachusetts	205629.6	192838.7	25306.1	13.1	12.3
New Hampshire	48531.8	43328.1	3529.2	8.1	7.3
New Jersey	76893.3	61600.9	882.8	1.4	1.1
New York	398048.9	369594.6	70397.9	19.0	17.7
Pennsylvania	449572.9	391896.9	76946.6	19.6	17.1
Rhode Island	9439.7	8294.6	3018.0	36.4	32.0
Vermont	57633.7	56130.6	2645.1	4.7	4.6
MANE-VU	1613112.0	1452286.6	227634.0	16.6	14.3

[1] SCC 23110xxxx

Table 3: 2002 $PM_{2.5}$ emissions from diesel emissions (Data Source: 2002 MANE-VU Modeling Inventory, Version 3.0)

State	Total Emissions from All Sources $PM_{2.5}$ (tons/year)	Total Nonroad Source Emissions $PM_{2.5}$ (tons/year)	Total Off-Highway Diesel Emissions $PM_{2.5}$ (tons/year)[1]	Construction Emissions as a % of Nonroad Source Emissions	Construction Emissions as a % of Total Inventory
Connecticut	18365.9	1793.9	582.5	32.5	3.2
Delaware	8210.2	925.6	215.3	23.3	2.6
District of Columbia	1612.8	298.7	235.9	79.0	14.6
Maine	40824.9	1329.4	261.8	19.7	0.6
Maryland	38929.7	4357.1	1161.6	26.7	3.0
Massachusetts	51864.4	3226.4	1032.0	32.0	2.0
New Hampshire	21996.8	965.4	268.0	27.8	1.2
New Jersey	31595.3	4997.2	1437.4	28.8	4.5
New York	108952.6	8820.9	2556.2	29.0	2.3
Pennsylvania	108811.6	8440.1	1862.7	22.1	1.7
Rhode Island	2901.3	443.1	128.7	29.0	4.4
Vermont	12300.3	485.8	109	22.4	0.9
MANE-VU	446365.9	36083.6	9851.2	27.3	2.2
[1] SCC 2270002xxx					

Table 4: 2002 PM_{10} emissions form diesel emissions (Data Source: 2002 MANE-VU Modeling Inventory, Version 3.0)

State	Total Emissions from All Sources PM_{10} (tons/year)	Total Nonroad Source Emissions PM_{10} (tons/year)	Total Off-Highway Diesel Emissions PM_{10} (tons/year)[1]	Construction Emissions as a % of Nonroad Source Emissions	Construction Emissions as a % of Total Inventory
Connecticut	53430.1	1952.1	633.2	32.4	1.2
Delaware	18857.7	1021.4	234.0	22.9	1.2
District of Columbia	6986.7	310.2	243.2	78.4	3.5
Maine	178918.5	1436.8	269.9	18.8	0.2
Maryland	112193.1	4936.0	1262.7	25.6	1.1
Massachusetts	205629.6	3531.2	1121.7	31.8	0.5
New Hampshire	48531.8	1057.8	291.3	27.5	0.6
New Jersey	76893.3	5495.1	1562.3	28.4	2.0
New York	398048.9	9605.3	2778.5	28.9	0.7
Pennsylvania	449572.9	9737.9	2024.7	20.8	0.5
Rhode Island	9439.7	500.2	139.9	28.0	1.5
Vermont	57633.7	529.9	118.5	22.4	0.2
MANE-VU	1616136.2	40113.9	10679.9	26.6	0.7
[1] SCC 2270002xxx					

Data on area source emissions and the total emissions for $PM_{2.5}$ and PM_{10} are also shown in Tables 1 and 2. Both tables show that construction dust is a major contributor to total emissions of $PM_{2.5}$ and especially PM_{10} with 5.1% and 14.3% emission contribution respectively. The MANE-VU states with the largest contribution to $PM_{2.5}$ emissions are the District of Columbia, Rhode Island, Maryland, and Pennsylvania. The MANE-VU states with the largest contribution to PM_{10} emissions are the Rhode Island, Maryland, and the District of Columbia.

Data on off-highway and nonroad diesel emissions sources for $PM_{2.5}$ and $_{10}$ are also shown in Tables 3 and 4. These tables show that diesel emissions do not contribute significantly to $PM_{2.5}$ and PM_{10} emissions with 2.2% and 0.7% respectively. However, they do make a contribution to PM emissions. According to Table 3, the District of Columbia, New Jersey, and Pennsylvania contribute the most to $PM_{2.5}$ diesel emissions of all the MANE-VU states. The District of Columbia, New Jersey, and Rhode Island contribute the most to PM_{10} diesel emissions in MANE-VU states as seen in Table 4. Construction emissions are a large percentage of the total PM inventory in urban areas, for example in the District of Columbia has the highest percentage of construction emissions as a percentage of nonroad source emissions and the total inventory.

It should be noted that “a fugitive dust transport fraction” is applied to emissions numbers for construction activities to account for dust settling out of the air close to the sources. This application essentially reduces fugitive dust emissions to approximately one-fourth of the emissions values before they are used in photochemical transport models. As a result of this application, photochemical models produce more consistent results with ambient air quality monitoring data. In addition, the EPA has recently recommended that a new emissions factor be used in determining fugitive dust emissions from construction activities. MANE-VU States have agreed to use the new emissions factor, and, as a result, the values for $PM_{2.5}$ and PM_{10} emissions from construction activities are significantly lower in Version 3.0 of the 2002 MANE-VU Modeling Inventory, compared to Version 2.0 of the 2002 MANE-VU Modeling Inventory.

4. Ambient Air Quality Monitoring Data

The Northeast States for Coordinated Air Use Management (NESCAUM), on behalf of MANE-VU, analyzed ambient air quality data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) network in several areas within and near Class I Areas in the Northeast and Mid-Atlantic Region. Figure 1 shows the relative contributions of sulfate, nitrate, organic carbon, crustal material, elemental carbon, and Rayleigh scattering to visibility impairment on the 20% clearest and 20% haziest days in 1999. Construction activities contribute only a fraction to the crustal material emissions that were measured and diesel emissions from construction sites contribute to elemental carbon, nitrate, and organic carbon.

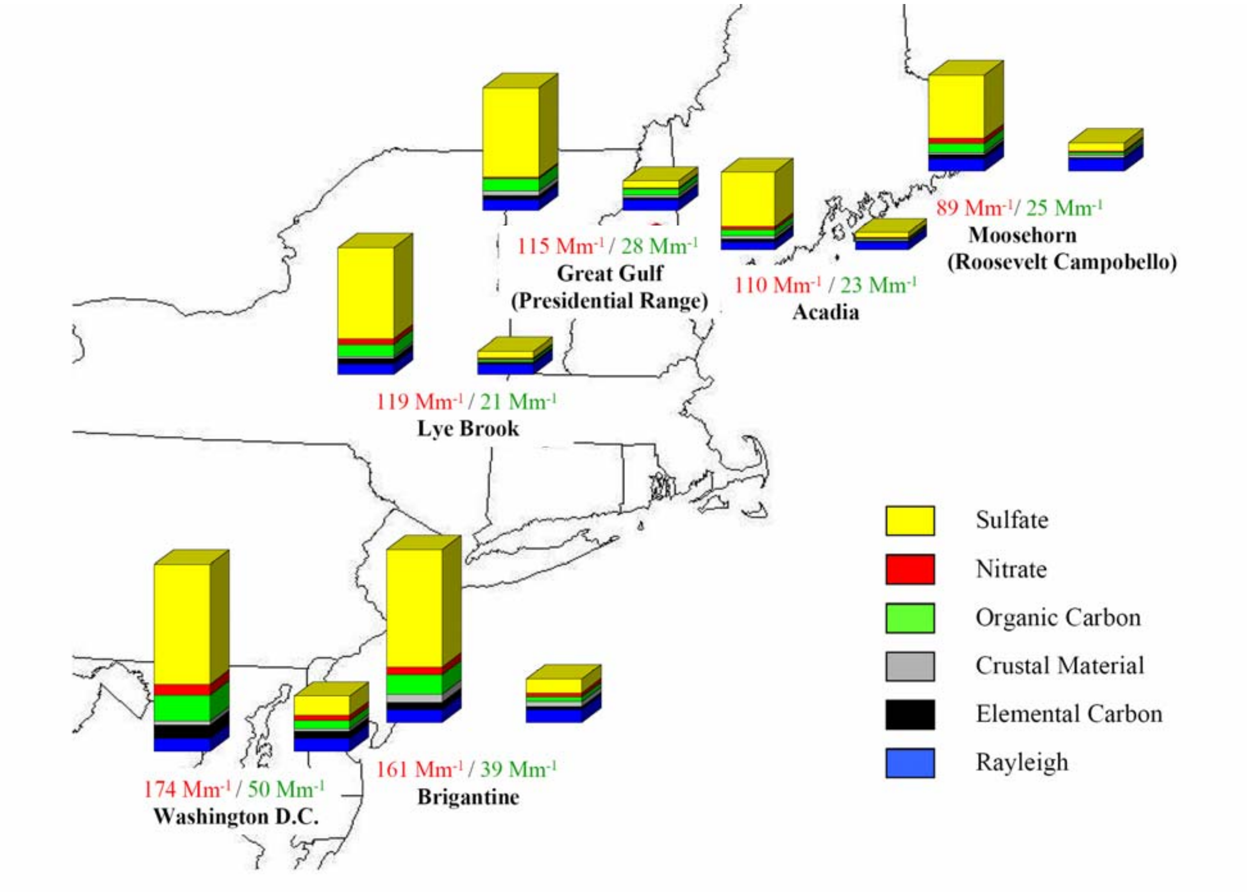

Figure 1: Speciated contribution to total atmospheric light extinction in or near Class I Areas in the Northeast and Mid-Atlantic states on 20 percent of days with the worst (left bar) and best (right bar) visibility conditions during 1999. (Source: Technical Memorandum #1: Updated Statistics for the MANE-VU Region, prepared by the Northeast States for Coordinated Air Use Management, on behalf of MANE-VU in February 2002. The memorandum is available online at http://bronze.nescaum.org/regionalhaze/memoranda/Memo1-VisData.pdf.)

On the 20% haziest days in 1999, sulfate was the greatest contributor to visibility impairment at all of the sites analyzed, and sulfate and Rayleigh scattering were the largest contributors on the 20% clearest days in 1999. Crustal material, including dust from construction activities and other sources of dust, was only a minor contributor to haze on the 20% clearest and haziest days in 1999.

Data from the IMPROVE monitoring network has also been analyzed to estimate the contribution of soil dust to $PM_{2.5}$ concentrations across the nation. Figure 2 shows the results of an analysis on 2001 IMPROVE data.

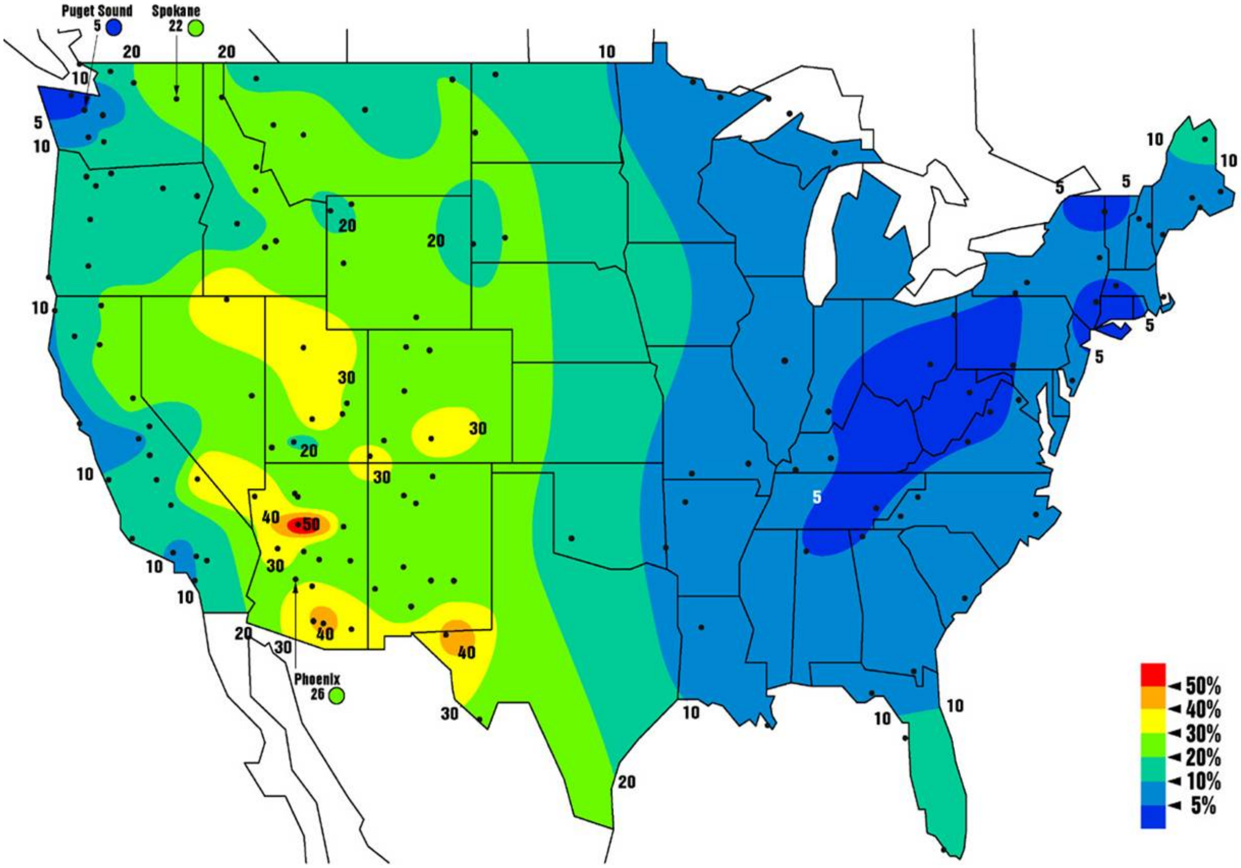

Figure 2: Annual Soil Fraction of Fine Particle Mass (2001). (Source: "Spatial and Seasonal Patterns in Speciated Fine Particle Concentration in the Rural United States," a presentation by Bret Schichtel of the National Park Service and William Malm, Marc Pitchford, Lowell Ashbaugh, Robert Eldred, and Rodger Ames, made available online by IMPROVE at http://vista.cira.colostate.edu/improve/Publications/GrayLit/gray_literature.htm.)

According to IMPROVE results, whereas soil dust contributes more than 50% of the $PM_{2.5}$ mass in parts of the western United States, dust contributes less than 10% in the Mid-Atlantic and Northeast Regions of the United States. Construction activities are not the only sources of construction dust in the Region. Other sources of fugitive dust, such as dust from paved and unpaved roads and agricultural tilling practices, are also significant sources. Since construction dust only partially comprises the total dust component and since soil dust is not a large contributor to ambient $PM_{2.5}$ concentrations, dust from construction activities is unlikely a large component of $PM_{2.5}$ concentrations measured in MANE-VU Class I Areas. These results confirm the NESCAUM findings that dust is not a major contributor to haze in the Region.

5. Potential Available Control Measures

There are several control options for reducing dust and diesel emissions from construction activities. The most common methods for controlling dust emissions include watering surface materials and minimizing surface wind speed using windbreaks or source enclosures. Chemicals can also be used to stabilize surface materials, but these methods can be expensive and/or have adverse ecological effects. Dust minimization techniques used when hauling dirt include covering trucks and rapidly cleaning up spillage. Early paving of permanent roads can also help control dust during certain construction activities. In the case of reducing diesel emissions, four options have been utilized with success. The use of cleaner fuels (e.g., low sulfur, emulsified diesel), the installation of exhaust controls (e.g., diesel oxidation catalysts), placing limitations on the time and location of idling machines, and assuring that heavy duty vehicles comply with state regulations (e.g., smoke standards).

6. Existing Regulations

Most MANE-VU states and the District of Columbia have regulations in place to control dust emissions from construction activities that are relevant to regional haze and certain MANE-VU states have regulations in place to control diesel emissions. MARAMA requested information regarding state control measures, and received responses from every MANE-VU state and the District of Columbia. The following descriptions of state regulations incorporate the information provided by Connecticut (Michael Geigert and Merrily Gere), Delaware (Jack Sipple), the District of Columbia (Rama Tangirala), Maine (Jeff Crawford), Maryland (Brian Hug), Massachusetts (Ken Santlal and Eileen Hiney), New Hampshire (Andy Bodnarik), New Jersey (Ray Papalski), New York (John Kent), Pennsylvania (Nancy Herb), Rhode Island (Ted Burns), and Vermont (Paul Wishinski). The following descriptions are provided as background information and are not intended to incorporate any regulations, policies, programs or projects into the State Implementation Plan.

6.1 Connecticut

Section 22a-174-18 of the Regulations of Connecticut State Agencies, “Control of particulate matter and visible emissions,” addresses the control of airborne particulate matter and fugitive particulate matter in subsections (c) and (d). These regulations, which include dust control measures and visible emissions from diesel powered mobile sources, apply to road building and construction activities. Regulations are available online at http://www.dep.state.ct.us/air2/regs/mainregs.htm.

Two additional emissions control programs related to construction activities are currently underway in Connecticut. First, the Connecticut Clean Air Construction Initiative is a 10-year pilot project designed to reduce idling and operational emissions from construction equipment used to complete the I-95 New Haven Harbor Crossing Improvement Project also called the Q Bridge Project. Retrofits and idling restrictions for this project are required as part of contract specifications with the Connecticut Department of Transportation (CTDOT). Diesel retrofits and idling restrictions for construction vehicles were also written into a special act called the Connecticut Clean Diesel Plan by the Connecticut Department of Environmental Protection (CTDEP). The CTDEP hopes to work with CTDOT to expand this program to all state road construction projects. Currently, 150 diesel powered construction machines have been retrofits with oxidation catalysts and by the projects completion 200 machines will be retrofitted.

Second, a PM_{10} limited maintenance plan for the City of New Haven was approved by EPA. The plan includes some contingency measures that apply to New Haven under a state order. The measures focus on street paving and sweeping.

The Connecticut Department of Transportation has implemented diesel vehicle emission controls that Contractors and Sub-contractors are obligated to follow. Any non-road construction equipment with engine horsepower (HP) rating of 60 HP and above that are assigned to a contract for a period in excess of 30 consecutive calendar days must be retrofitted with Emission Control Devices and/or use Clean Fuels in order to reduce diesel emissions. Contractors must submit a certified list of non-road diesel powered construction equipment what will be retrofitted with emission control devices and/or use Clean Fuel and include the addition or deletion of non-road diesel equipment. The list has three parts and a monthly report must also be submitted by the contractor updating the above stated information. If these rules are not followed the contractor will be issued a Non-Compliance and given 24 hours to bring the equipment into compliance or removed it from the project. If the contractor still does not comply further and more extreme actions will be taken. For further information on this project contact the Connecticut Department of Transportation, regarding the I-95 New Haven Harbor Crossing Corridor Improvement Program.

Connecticut has regulations in place to control fugitive emissions from construction. In Section 22a-174-18(c) of regulations from the Department of Environmental Protection state that, “No person shall cause or allow the emission of visible particulate matter beyond the legal boundary of the property on which such emission occurs that either diminishes the health, safety or enjoyment of people using a building or structure located beyond the property boundary…No person shall emit particulate matter into the ambient air in such a manner as to cause a nuisance.” The regulations also place strict controls on the type and amount of visible particulate matter that can be released by the owner or operator of the equipment. These regulations are available online at: http://www.dep.state.ct.us/air2/regs/mainregs/sec18.pdf

6.2 Delaware

Delaware Air Quality Management (AQM) Regulation 6, “Particulate Emissions from Construction and Materials Handling,” addresses control measures for particulate emissions from construction and materials handling operations to minimize air pollution. This regulation is available online at http://www.dnrec.state.de.us/air/aqm_page/docs/pdf/reg_6.pdf.

Delaware has no regulations or laws to control emissions from diesel equipment at construction sites.

6.3 District of Columbia

Chapter 6 of the Title 20 D.C. Municipal Regulations (20 DCMR), addresses control measures for particulate matter. Section 605 of 20 DCMR "Control of Fugitive Dust" specifically addresses the fugitive dust control measures that apply to roads, parking lots, vehicles transporting dusty materials, loading & unloading and demolition of buildings activities. Additionally, Section 903 of the Title 20 DCMR addresses odorous or other nuisance air pollutants.

There are no regulations or laws in place to control emissions from diesel at construction sites in Washington D.C. However, there are restriction on the use of heavy duty diesel engines produced for the 2005 and 2006 model years and heavy duty vehicles containing these engines. These vehicles are not allowed to be registered in the District of Columbia without the applicant presenting documentation that the California Air Resources Board has issued an Executive Order for the vehicle or engine certifying that it complies with the applicable exhaust emission standards under the California Code of Regulations. The emission standards for these engines are referenced to CARB Title 13, section 1956.8 which are available online at http://www.calregs.com/linkedslice/default.asp?SP=CCR-1000&Action=Welcome.

6.4 Maine

The Department of Environmental Protection (DEP) Regulations Chapter 101, "Visible Emissions," establishes opacity limitations for emissions from several categories of air contaminant sources, including fugitive emissions. DEP Regs Chapter 101 can be applied to construction activities and is available online at http://www.maine.gov/sos/cec/rules/06/096/096c101.doc

Maine has no regulations or laws to control emissions from diesel equipment at construction sites.

6.5 Maryland

COMAR 26.11.06.03D addresses "Particulate Matter from Materials Handling and Construction." This regulation, available online at http://www.dsd.state.md.us/comar/26/26.11.06.03.htm, states that during construction activities there must be "reasonable precautions to prevent particulate matter from becoming airborne" and lists possible control measures.

Maryland has no regulations or laws to control emissions from diesel equipment at construction sites.

6.6 Massachusetts

Control measures to mitigate the emission of particulate matter from construction activities are included in the Massachusetts Department of Environmental Protection Air Pollution Patrol regulations. According to regulation 310 CMR 7.09, "No person having control of any dust or odor generating operations such as construction work shall permit emissions therefrom which cause or contribute to air pollution," and written notification to the Department is required ten working days prior to the initiation of construction.

According to regulation 310 CMR 7.06, "No person shall cause, suffer, allow, or permit excessive emission of visible air contaminants, other than water, from a diesel engine." In addition regulation 310 CMR 7.11 states that, "All motor vehicles registered in the Commonwealth shall comply with pertinent regulations of the Registry of Motor Vehicles relative to exhaust and sound emissions."

Regulation 310 CMR 7.06, 7.09 and 7.11 are available online at http://www.mass.gov/dep/air/laws/7b.htm#09

6.7 New Hampshire

Fugitive dust control measures for construction activities are included in CHAPTER Env-A 1000, "Prevention, Abatement, and Control of Open Source Air Pollution," PART Env-A 1002, "Fugitive Dust." Subsection Env-A 1002.04, "Precautions to Prevent, Abate, and Control Fugitive Dust," lists potential dust control measures and is available online at http://www.gencourt.state.nh.us/rules/env-a1000.html.

New Hampshire has no regulations or laws to control emissions from diesel equipment at construction sites.

6.8 New Jersey

Fugitive emissions are regulated under the New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 8 (NJAC 7:27-8 et seq.); Permits and Certificates, available on-line at http://www.state.nj.us/dep/aqm/rules.htm. Dust control measures for construction are not specifically mentioned. Any off-site impacts from construction activities are also prevented by NJAC 7-27-5 et seq. - Prohibition of Air Pollution that prevents any activity from being injurious to human health or welfare at any off-site location.

New Jersey has recently passed the Diesel Retrofit Law which is expected to reduce particulate emissions from some equipment that will be used in municipal construction or maintenance projects. The 2005 diesel retrofit law regulates publicly-owned off-road equipment in New Jersey by requiring retrofitting with exhaust particulate emissions control systems. The Department of Environmental Protection is charged with designating Best Available Retrofit Technology and defining specific types of equipment to be retrofitted. The law limits the choices of BART to those verified under the EPA and CARB diesel emissions control strategy verification programs. A constitutionally dedicated portion of the State Corporate Business Tax serves as the funding source to reimburse the retrofit costs.

6.9 New York

The New York State Department of Environmental Conservation Rules and Regulations Part 211, “General Prohibitions” includes a clause that places limits on particulate emissions, 211.3, “Visible emissions limited.” The regulation is available online at http://www.dec.state.ny.us/website/regs/part211.html

In addition, the New York State Department of Transportation (NYSDOT) Environmental Procedures Manual Chapter 1.1 Section 15, “Construction Related Air Quality Impacts,” addresses air quality issues associated with construction activities and includes possible control measures. This manual is available online at http://www.dot.state.ny.us/eab/epm.html.

New York has no regulations or laws to control emissions from diesel equipment at construction sites.

6.10 Pennsylvania

25 PA Code, Chapter 123, Sections 123.1, “Prohibition of certain fugitive emissions,” and 123.2, “Fugitive particulate matter,” regulate emissions from construction and other related activities. These regulations were adopted on September 10, 1971 and have been “SIP approved.” These regulations are available online at http://www.pacode.com/secure/data/025/chapter123/s123.1.html and http://www.pacode.com/secure/data/025/chapter123/s123.2.html.

Pennsylvania does not have regulations to control emissions from diesel equipment at construction sites. However, permits are required for the operation of diesel and nonroad engines. Section 2 of the both the General Plan Approval And/Or General Operating Permit (BAQ-GPA/GP 9) and the General Plan Approval And/Or General Operating Permit (BAQ-GPA/GP 11), states that nonroad and diesel engines must have the best available technology (BAT) installed and in operation and compliance so that the diesel engine is in compliance with regulated emissions standards. Both General Permits (GPs) require the permittee to maintain accurate records of the amount of time the engine is in operation per month, including the amount of fuel used for each unit. GP 9 is more specific about the emissions limits for diesel engines and these are different depending on when construction commenced and the location of the construction. GP 9 and GP11 are available online at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp.htm.

6.11 Rhode Island

The RI Department of Environmental Management Air Pollution Control Regulation No. 5, “Fugitive Dust,” regulates fugitive dust generated by numerous operations that include construction activities. The regulation is available online at http://www.dem.ri.gov/pubs/regs/regs/air/air05_96.pdf.

Rhode Island has no regulations or laws to control emissions from diesel equipment at construction sites.

6.12 Vermont

Regulation 5-231 (4) in Vermont's Air Pollution Control Regulations addresses fugitive particulate matter emissions. The regulation states that reasonable precautions must be taken to prevent particulate matter from becoming airborne during the construction of buildings and non-public roads and the handling, transport, and storage of materials. This regulation is available online at http://www.anr.state.vt.us/air/docs/apcregs.pdf.

In addition to this rule, most of Vermont's new source permits include references to fugitive emissions. New source permits typically include language such as, "The Permittee shall take reasonable precautions at all times to control and minimize emissions of fugitive particulate matter from operations at the Facility," and list possible control measures.

Vermont has no regulations or laws to control emissions from diesel equipment at construction sites.

7. Conclusions

The following statements summarize the main points of this technical support document.

- Although a temporary source, fugitive dust and diesel emissions from construction activities can have an affect on local air quality.
- While construction activities are responsible for a relatively large fraction of direct $PM_{2.5}$ and PM_{10} emissions in the Region, the impact on visibility is less because dust settles out of the air relatively close to the sources.
- Ambient air quality data shows that soil dust makes up only a minor fraction of the $PM_{2.5}$ measured in MANE-VU Class I Areas, and impacts of diesel emissions in these rural areas are also a small part of total $PM_{2.5}$.
- The use of measures such as clean fuels, retrofit technology, best available technology, specialized permits, and truck staging areas (to limit the adverse impacts of idling) can help decrease the effects of diesel emissions on local air quality.
- MANE-VU States have rules in place to mitigate potential impacts of construction on visibility in Class I Areas.

TECHNICAL SUPPORT DOCUMENT FOR 2002 MANE-VU SIP MODELING INVENTORIES, VERSION 3

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November 20, 2006

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

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CONTENTS

TABLES

FIGURES

ACRONYMS AND ABBREVIATIONS

ATP	Anaerobic Thermal Processor
BEIS	Biogenic Emissions Inventory System
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMD	Clean Air Markets Division
CAP	criteria air pollutant
CE	Control Equipment (NIF 3.0) table
CEM	Continuous Emissions Monitoring
CENRAP	Central Regional Air Planning Organization
CERR	Consolidated Emissions Reporting Rule
CMU	Carnegie Mellon University
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
EF	emission factor
EFIG	Emission Factors and Inventory Group
EGU	electricity generating unit
EI	inventory
EM	Emission (NIF 3.0) table
EP	Emission Process (NIF 3.0) table
EPA	U.S. Environmental Protection Agency
ERP	Emission Release Point (NIF 3.0) table
ETBE	ethyl tertiary butyl ether
ETOH	ethanol
ETS	Emission Tracking System
EU	Emission Unit (NIF 3.0) table
FIPS	Federal Information Processing Standard
FIRE	Factor Information and REtrieval Factor
GIS	geographic information system
GSE	ground support equipment
HAP	hazardous air pollutant
HC	hydrocarbon
HPMS	Highway Performance Monitoring System
ID	identification
IDA	Inventory Data Analyzer format
I/M	inspection and maintenance
km	kilometer
LAI	leaf area indices
LEV	low emission vehicle
LPG	liquified petroleum gas
MACT	maximum achievable control technology
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MARAMA	Mid-Atlantic Regional Air Management Association
MTBE	methyl tertiary butyl ether
NAAQS	National Ambient Air Quality Standard
NAICS	North American Industrial Classification System

NEI	National Emissions Inventory
NH_3	ammonia
NIF	NEI Input Format
NMIM	National Mobile Inventory Model
NO	nitrous oxide
NO_x	oxides of nitrogen
NYSDEC	New York State Department of Environmental Conservation
ORIS	Office of Regulatory Information Systems
OTC	Ozone Transport Commission
PAR	photosynthetic active radiation
PE	Emission Period (NIF 3.0) table
Pechan	E.H. Pechan & Associates, Inc.
PFC	portable fuel container
PM	particulate matter
PM-CON	condensible PM
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PM10-FIL	filterable PM_{10}
PM10-PRI	primary PM_{10}
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM25-FIL	filterable $PM_{2.5}$
PM25-PRI	primary $PM_{2.5}$
POTWs	public owned treatment works
ppm	parts per million
psi	pounds per square inch
QA	quality assurance
QAPP	Quality Assurance Project Plan
RPO	Regional Planning Organization
RVP	Reid vapor pressure
SCC	Source Classification Code
SPDPRO	speed profile
SPDREF	speed cross reference
SI	Site (NIF 3.0) table
SIC	Standard Industrial Classification
SIP	State Implementation Plan
S/L	State and Local
SMOKE	Sparse Matrix Operator Kernel Emissions
SO_2	sulfur dioxide
TAME	tertiary amyl methyl ether
TR	Transmittal (NIF 3.0) table
TSD	technical support document
U.S.	United States
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
VMT	vehicle miles traveled
VOC	volatile organic compound
WRAP	Western Regional Air Partnership

CHAPTER I – INTRODUCTION

A. What is the purpose of this TSD?

This technical support document (TSD) explains the data sources, methods, and results for preparing Version 3 of the 2002 base year criteria air pollutant (CAP) and ammonia (NH_3) emissions inventories for point, area, onroad, nonroad, and biogenic sources for the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Regional Planning Organization (RPO). The MANE-VU region includes Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. Local air planning agencies include Philadelphia and Allegheny County, Pennsylvania. The region also includes the Penobscot Tribe of Maine Indian Nation (Tribal code 018) and the St. Regis Band of Mohawk Indians of New York (Tribal code 007). However, these tribal authorities did not provide any data for the 2002 MANE-VU inventory. MANE-VU will use these inventories to support air quality modeling, State Implementation Plan (SIP) development, and implementation activities for the regional haze rule and fine particulate matter (PM) and ozone National Ambient Air Quality Standards (NAAQS).

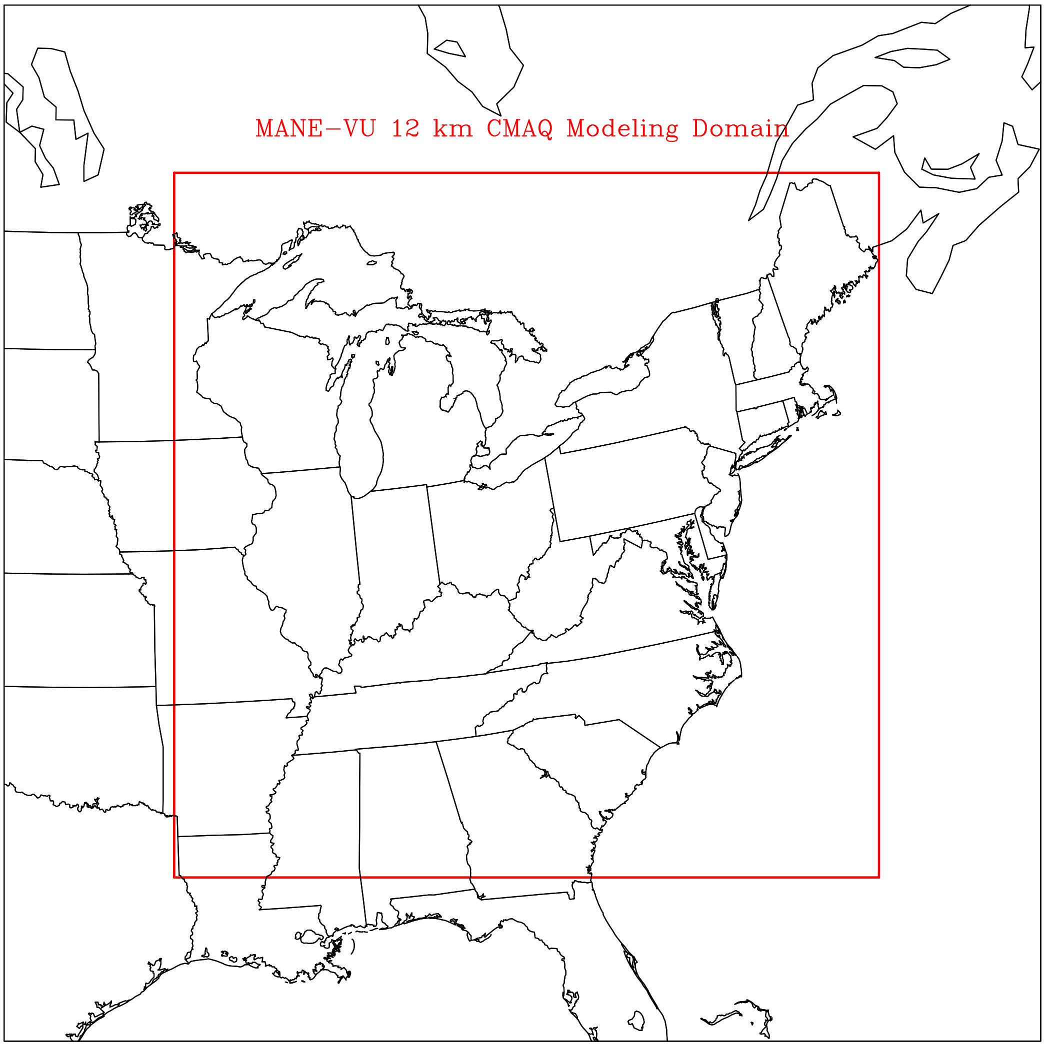
The inventories and supporting data prepared include the following:

(1) Comprehensive, county-level, mass emissions and modeling inventories for of 2002 emissions for CAPs and NH_3 for the State and Local (S/L) agencies included in the MANE-VU region;
(2) The temporal, speciation, and spatial allocation profiles for the MANE-VU region inventories;
(3) Inventories for wildfires, prescribed burning, and agricultural field burning for the southeastern provinces of Canada; and
(4) Inventories for other RPOs, Canada, and Mexico.

The mass emissions inventory files were prepared in the National Emissions Inventory (NEI) Input Format Version 3.0 (NIF 3.0). The modeling inventory files were prepared in Sparse Matrix Operator Kernel Emissions/Inventory Data Analyzer (SMOKE/IDA) format. Ancillary files (holding spatial, temporal, and speciation profile data) were prepared in SMOKE/IDA compatible format. Figure 1 shows the Models-3 Community Multiscale Air Quality Modeling System (CMAQ) modeling domain for the MANE-VU region.

The inventories include annual emissions for sulfur dioxide (SO_2), oxides of nitrogen (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), NH_3, and particles with an aerodynamic diameter less than or equal to a nominal 10 and 2.5 micrometers (i.e., primary PM_{10} and $PM_{2.5}$). The inventories included summer day, winter day, and average day emissions. However, not all agencies included daily emissions in their inventories, and, for the agencies that did, the temporal basis for the daily emissions varied between agencies. The temporal profiles prepared for this project will be used to calculate daily emissions when not available in the inventory files.

Figure 1. MANE-VU 12-Kilometer CMAQ Modeling Domain



B. What are Versions 1, 2, and 3 of the 2002 MANE-VU Inventory?

Work on Version 1 of the 2002 MANE-VU inventory began in April 2004. The consolidated inventory for point, area, onroad, and nonroad sources was prepared by starting with the inventories that S/L agencies submitted to the United States (U.S.) Environmental Protection Agency (EPA) from May through July of 2004 as a requirement of the Consolidated Emissions Reporting Rule (CERR). The EPA's format and content quality assurance (QA) programs (and other QA checks not included in EPA's QA software) were run on each inventory to identify format and/or data content issues (EPA, 2004a). E.H. Pechan & Associates, Inc. (Pechan) worked with the MANE-VU S/L agencies and the staff of the Mid-Atlantic Regional Air Management Association (MARAMA) to resolve QA issues and augment the inventories to fill data gaps in accordance with the Quality Assurance Project Plan (QAPP) prepared for this project (MANE-VU, 2004a). MARAMA is the MANE-VU organization's employees, whereas

MANE-VU is the member S/L agencies plus MARAMA employees. MARAMA is one of three RPOs (in addition to Ozone Transport Commission (OTC) and North East States for Coordinated Air Use Management) supporting the MANE-VU effort.

A draft of the point and area source inventories and summary files were provided for stakeholder review during August 2004. Stakeholder comments were reviewed by the S/L agencies and revisions to the inventory files were made to the files to incorporate stakeholder comments as approved by each S/L agency. The inventories were finalized during December 2004 and the SMOKE input files were prepared and reviewed by the modelers during December 2004 and early January 2005. The final inventory and SMOKE input files were finalized during January 2005.

Work on Version 2 (covering the period from April through September 2005) involved incorporating revisions requested by some S/L agencies on the point, area, and onroad inventories. Work on Version 3 (covering the period from December 2005 through April 2006) included additional revisions to the point, area, and onroad inventories as requested by some states. Thus, the Version 3 inventory for point, area, and onroad sources were built upon Versions 1 and 2. This work also included development of the biogenics inventory. Version 3 of the nonroad inventory was completely redone due to changes that EPA made to the NONROAD2005 model.

C. How is this TSD organized?

Chapters II through V of this TSD present the general and State-specific methods and data sources used to develop Version 3 of MANE-VU's 2002 inventory for point, area, nonroad, and onroad sources. Chapter VI presents the methods, data sources, and model used to develop the biogenics inventory. Chapter VII documents the temporal allocation, speciation, and spatial allocation modeling input files used for Version 3 of MANE-VU's 2002 inventory for all sectors. Chapter VIII describes the non-MANE-VU region inventory data used for MANE-VU BaseB Modeling. References for the TSD are provided in Chapter IX. Appendices A and B provide the QA Summary Report files prepared during development of the State-specific inventories for point and area sources, respectively. Appendices A and B also provide tables that identify for each S/L agency, the Version 3 data sources, emission type period, pollutant, and the number of counties by source classification code (SCC). For the nonroad inventory, Appendix C provides the final county, monthly National Mobile Inventory Model (NMIM) inputs provided or confirmed by the States for Reid vapor pressure (RVP), weight percent oxygen, and gasoline sulfur.

CHAPTER II – POINT SOURCES

A. General Methods for all State and Local Agencies

1. What Data Sources Were Used?

Version 3 of the 2002 MANE-VU point source inventory is based primarily on Version 1 with some state-specific revisions incorporated into Versions 2 and 3. Version 1 was developed using the inventories that S/L agencies submitted to EPA from May through July of 2004 as a requirement of the CERR. All 12 State agencies submitted point source inventories to EPA. In addition, Allegheny and Philadelphia Counties in Pennsylvania each submitted their own point source inventories to EPA. The EPA performed some limited QA review of the S/L inventories to identify format, referential integrity, and duplicate record issues. The EPA revised the inventories to address these issues and made the files available to the S/L agencies on August 6, 2004. These inventory files were used as the starting point for Version 1 of the MANE-VU inventory. These inventory files were obtained from EPA, consolidated into a single data set, subjected to extensive QA review, revised (as approved by the MANE-VU S/L agencies) to address QA issues and to fill data gaps identified while preparing Version 1. Subsequently, the following agencies provided revisions to their point source inventories:

- Version 2 – Connecticut, Delaware, and Maryland
- Version 3 – Massachusetts, New York, and Rhode Island

The revisions that these states provided for Versions 2 and 3 are discussed in the "State-Specific Methods" section of this chapter.

In order to track the origin of data, the temporal period of emissions, and to facilitate generation of emission summaries, the following NIF plus fields were added to the Transmittal (TR), Site (SI), Emission Unit (EU), Emission Release Point (ER), Emission Process (EP), Emission Period (PE), Emission (EM), and Control Equipment (CE) tables:

- Data Source Codes:

Code	Description
S	State agency-supplied data.
L	Local agency-supplied data to incorporate S/L comments for individual records.
P	NH_3 emissions from MANE-VU inventory for cement kilns.
AUG-A	PM Augmentation: ad-hoc change.
AUG-C	PM Augmentation: standard augmentation method.
AUG-O	PM Augmentation: set PMxx-FIL = PMxx-PRI for SCCs starting with 10 (external fuel combustion) and 20 (internal fuel combustion). Note: emission factors and particle-size data for estimating condensible emissions for fuel combustion SCCs starting with 30 were not available; therefore, condensible emissions were not estimated for these processes

	if an agency provided filterable and not primary emissions for these processes. In other words, the primary emissions were assumed to equal the filterable emissions.
AUG-Z	PM Augmentation: automated fill-in of zero values where all PM for a particular process is zero.

- Revision Date: This field indicates the month and year during which the last revision was made to a record.

- State Federal Information Processing Standard (FIPS): This field indicates the state FIPS code of the submittal.

- County FIPS: This field indicates the county FIPS code of the submittal.

The following NIF plus fields were added to the EM table:

- Emission Ton Value: This field indicates the values of the emissions in tons. This field was used to prepare summaries of emissions on a consistent EU basis.

- Emission Type Period: This field indicates the period of the Emission Type – either ANNUAL or NONANNUAL. This field was used to prepare summaries of annual emissions.

- CAP_HAP: This field identifies records for CAP versus records for hazardous air pollutants (HAPs). For the MANE-VU inventory, the flag is CAP for all records.

- Year: This field indicates the year of the data; for this inventory, it is 2002.

Note that the QAPP for Version 1 includes more data source codes than were used in Version 3 of the point source inventory. The data source codes listed above are the codes used in Version 3. The exception is for Rhode Island, who requested that their Version 2 inventory be replaced with its inventory included in the final 2002 NEI prepared by EPA. Thus, for Rhode Island, it was agreed to maintain the data source codes used in the NEI in Version 3 of the MANE-VU inventory. The data source codes for Rhode Island's point source inventory are explained under the state-specific section for Rhode Island.

2. What Quality Assurance Steps Were Performed?

A QAPP was prepared and approved by MANE-VU/MARAMA and the EPA Regional Office prior to initiating work on Version 1 of the inventory (MANE-VU, 2004a). This QAPP was followed during preparation of all three versions of the inventory. This section provides an overview of the QA checks completed on each version of the inventory. The QA process for each S/L inventory involved the following steps:

- Conduct QA checks on each S/L inventory;
- Prepare a QA Summary Report for submittal to the agency for review;

- Revise the inventory to resolve QA issues as directed by the agency;
- Repeat the QA checks on the revised inventory to verify that the corrections were completed;
- Perform augmentation to correct for missing data; and
- Repeat the QA checks to verify that the augmentation was completed correctly.

a. QA checks for S/L agency inventories

The following discusses the QA diagnoses that were run on the consolidated point source inventory data set. For each S/L agency, a "QA Summary Report" was prepared for each QA check in an Excel Workbook file. The results of each QA check was summarized in a separate spreadsheet and submitted to the S/L agency for review and resolution. The agencies provided corrections to the data in the Excel files or via e-mail and the inventory was updated with the corrections.

i. Continuous Emissions Monitoring (CEM) Analysis

The goal of this analysis was to compare annual NO_x and SO_2 emissions that were measured with CEM systems and reported to EPA to the annual NO_x and SO_2 emissions reported in the S/L inventories. Facilities report hourly CEM data to EPA for units that are subject to CEM reporting requirements of the NO_x SIP Call rule and Title IV of the Clean Air Act (CAA). Thus, hourly CEM emissions were summed to the annual level and compared to the annual emissions in the S/L inventories. If the S/L agencies agreed, the CEM hourly emissions would be used to support air quality modeling to accurately reflect the temporal distribution of emissions from CEM units during 2002. Since some of the states require facilities to certify the emissions they report for inclusion in the inventory, the agencies needed proof that the emissions in the CEM inventory compared well with the emissions in the S/L inventory.

The 2002 CEM inventory containing hourly NO_x and SO_2 emissions and heat input data were downloaded from the EPA/Clean Air Markets Division's (CAMD) web site (www.epa.gov/airmarkets) on July 8, 2004 (CAMD, 2004). The data were provided by quarter and state resulting in 48 separate files for the 12 states in the MANE-VU region. For each state, the hourly emissions were summed to the annual level by facility and EU.

The first stage in the CEM analysis involved preparing a crosswalk file to match facilities and units in the CEM inventory to facilities and units in the S/L inventories. In the CEM inventory, the Office of Regulatory Information Systems (ORIS) identification (ID) code identifies unique facilities and the unit ID identifies unique boilers and internal combustion engines (i.e., turbines and reciprocating engines). In the S/L inventories, the state and county FIPS and state facility ID together identify unique facilities and the EU ID identifies unique boilers or internal combustion engines. However, in some of the S/L inventories, the emissions for multiple EUs were summed and reported under the same EU ID. Thus, an Excel Workbook was sent to the S/L agencies that contained an initial crosswalk with the ORIS ID and unit ID in the CEM inventory matched to the state and county FIPS, state facility ID, and EU ID in the S/L inventory. Agencies were asked to confirm/correct/supplement the information in the crosswalk. The initial crosswalk also contained annual emissions summed from the hourly CEM emissions and flags that indicated if

CEM units were subject to reporting requirements under the NO_x SIP Call and/or Title IV of the CAA. It should be noted that the initial matching of the IDs in both inventories was based on previous crosswalks that had been developed for the 1999 NEI and in-house information compiled by Pechan. The matching at the facility level was nearly complete; however, S/L agency assistance was needed to match most of CEM units to EUs in the S/L inventories.

The crosswalk was updated with corrections to facility and CEM unit-to-EU matches, and with new matches provided by the S/L agencies. The matching of each CEM unit to an EU was still incomplete. Consequently, the comparison of annual emissions was performed at the facility level.

The second stage in the CEM analysis was to prepare an Excel Workbook file for each S/L agency that compared the annual emissions summed from the hourly CEM inventory to the annual emissions reported in the S/L inventory. The file included three spreadsheets that compared annual emissions at the facility level, listed the facilities in the CEM inventory that could not be matched to the facilities in the S/L inventory, and listed the facilities in the S/L inventory identified as an electricity generating unit (EGU) that could not be matched to a facility in the CEM inventory. The Excel files were sent to the S/L agencies for review. The S/L agencies then indicated if they did or did not want to use the hourly CEM inventory.

The facility-level comparison of CEM to emission inventory NO_x and SO_2 emissions found that for some facilities, the annual emissions from the S/L inventory exceeded the CEM annual emissions because the facility in the S/L inventory contained more than just CEM units. This condition was determined to be acceptable. However, S/L agencies were asked to review data for facilities where the CEM emissions were higher than the emissions summed from the S/L inventory. For these cases, CEM emissions may be higher than those reported in a S/L inventory due to methods EPA uses for using artificially high default values to fill in hourly CEM data when not reported or when a CEM unit was not working properly.

After reviewing the comparison of the CEM to S/L inventory emissions, New York and Vermont elected to use the 2002 CEM inventory containing hourly NO_x and SO_2 emissions for all facilities. Maryland; New Hampshire; and Allegheny County, Pennsylvania elected to use the 2002 CEM data for some but not all of the facilities within their jurisdiction. The Excel Workbook files containing the comparison of CEM to S/L inventories provides a spreadsheet identifying the facilities for which these S/L agencies elected to use the CEM inventory.

Subsequent to the completion of this analysis, it was determined that the structure of the EPA/CAMD file would not be compatible with the format of the SMOKE input file. The database structure did not affect the annual emissions summed from the hourly CEM emissions used in the comparison to S/L inventory data. For each of the S/L agencies that elected to use the 2002 CEM data, CAMD agreed to provide separate database files for each state with a structure compatible with the SMOKE input file format. Pechan then used the crosswalk to add to the CEM inventory files the state and county FIPS, state facility ID, and EU ID (if the crosswalk contains a CEM unit to EU match) to the hourly CEM database files provided by CAMD. The modified database was then used to create the SMOKE input files for these states.

Note that Delaware requested that the 2002 CEM inventory for its facilities not be used for regional haze modeling. However, if the consolidated point source inventory prepared under this project is used to support ozone episode modeling, Delaware may consider using the CEM hourly data for the episodes modeled. Therefore, the 2002 CEM inventory was also processed for Delaware's facilities.

ii. PM Emissions Consistency and Completeness Review

The following consistency checks were performed at the EM table data key level (for annual emissions) to compare PM emissions:

- If a process was associated with a PM emission record, but was missing one or more of the following (as appropriate for the SCC [i.e., condensible PM (PM-CON) is associated with fuel combustion only]): filterable PM_{10} (PM10-FIL), primary PM_{10} (PM10-PRI), filterable $PM_{2.5}$ (PM25-FIL), primary $PM_{2.5}$ (PM25-PRI), or PM-CON, the record was flagged for review.

- The following equations were used to determine consistency:

  PM10-FIL + PM-CON = PM10-PRI
  PM25-FIL + PM-CON = PM25-PRI
  PM-FIL + PM-CON = PM-PRI

- The following comparisons were applied to determine consistency:

  PM10-PRI >= PM10-FIL
  PM25-PRI >= PM25-FIL
  PM10-PRI >= PM-CON
  PM25-PRI >= PM-CON
  PM10-FIL >= PM25-FIL
  PM10-PRI >= PM25-PRI
  PM-PRI >= PM10-PRI
  PM-PRI >= PM25-PRI
  PM-FIL >= PM10-FIL
  PM-FIL >= PM25-FIL

If the data failed one of these checks it was diagnosed as an error, summarized in an Excel Workbook file, and provided to the S/L agency for corrections. If a S/L agency did not provide corrections to these errors, the errors were corrected or filled in according to the augmentation procedures.

iii. ERP Coordinate Review

Location coordinates for point sources were evaluated using geographic information system (GIS) mapping to determine if the coordinates were within 0.5-kilometers of the boundary of the county in which the source was located. If not, the S/L agency was asked to review the coordinates and provide corrections to either the coordinates or the state and county FIPS codes. The 0.5-kilometer test resulted in a large number of ERPs for review by the agencies. Therefore, to assist S/L agencies in prioritizing their review of coordinates, ERP records with coordinates located more than 0.5, 1, 2, 3, 5, 7, and 10 or more kilometers from their county boundary, and coordinates that mapped outside of their state boundary were identified. Annual emissions summed to the ERP level were included in the QA Summary Report to identify records with zero emissions for all pollutants and to identify the highest emitting stacks. The QA Summary Report was provided to the S/L agency for review and corrections.

iv. ERP Parameter Review

The EPA's QA guidance for diagnosing ERP issues for the point source NEI (EPA, 2004b) was applied to identify QA issues in the S/L point source inventories. The QA guidance involved diagnosing the correct assignment of the ERP type (i.e., stack or fugitive), parameters with zero values, parameters not within the range of values specified in the EPA's QA procedures, and consistency checks (i.e., comparing calculated values against the values reported in the inventory). In many cases errors were caused by missing or zero values. In other cases, out-of-range errors were caused by unit conversion issues (e.g., stack parameters were in ft, ft/sec, cu ft/sec, or degrees Fahrenheit). The QA issues were summarized in a separate QA Summary Report for each agency and each agency was asked to provide corrections. If an agency did not provide corrections for out-of-range or missing values, the data were corrected or filled in according to the ERP augmentation procedures.

v. Control Device Type and Control Efficiency Data Review

The CE codes in the "Primary Device Type Code" and "Secondary Device Type Code" fields were reviewed to identify invalid codes (i.e., codes that did not exist in the NIF 3.0 reference table) and missing codes (e.g., records with a null or uncontrolled code of 000 but with control efficiency data).

QA review of control efficiency data involved diagnosis of two types of errors. First, records were reviewed to identify control efficiency values that were reported as a decimal rather than as a percent value. Records with control efficiencies with decimal values were flagged as a potential error (although not necessarily an error, since the real control efficiency may be less than 1%).

The second check identified records where 100% control was reported in the CE table, but the emissions in the EM table were greater than zero and the rule effectiveness value in the EM table was null, zero, or 100% (implying 100% control of emissions). Because many agencies did not populate the rule effectiveness field or a default value of zero was assigned, records with null or zero rule effectiveness values were included where the CE was 100% and emissions were greater than zero. The records that met these criteria were summarized in a QA Summary Report for review and correction, if necessary, by the S/L agency.

vi. Start and End Date Checks

QA review was conducted to identify start date and end date values in the PE and EM tables to confirm consistency with the inventory year in the TR table, and to confirm that the end date reported was greater than the start date reported. This check did not identify any QA issues in the three versions of the inventory.

vii. Annual and Daily Emissions Comparison

The following QA checks were conducted to identify potential errors associated with the incorrect reporting of daily and/or annual emissions:

- Any "DAILY" type record that is greater than its associated "ANNUAL".

A review of the daily vs. annual comparison revealed that in many cases, the daily value was nonzero (but very small), but the annual value was zero. This was generally a result of rounding in a S/L agency's original emissions database, where annual records were recorded in tons per year to a set number of decimal places, while the corresponding daily records were recorded in pounds per year to a set number of decimal places. The annual record rounds to zero in the original database, while the daily value remains non-zero. A tolerance check reveals the following (comparison in tons):

- Difference Tolerance (daily - annual)> 0
- Difference Tolerance (daily - annual)> .000001
- Difference Tolerance (daily - annual)> .00001
- Difference Tolerance (daily - annual)> .0001
- Difference Tolerance (daily - annual)> .001
- Difference Tolerance (daily - annual)> .01

For Version 1, the affected S/L agencies were as follows:

- Connecticut (09) 11 records
- Maine (23) 4 records
- Maryland (24) 72 records
- New Jersey (34) 2935 records
- Pennsylvania Allegheny County (42003) 17 records
- Pennsylvania Philadelphia County (42101) 146 records
- Rhode Island (44) 1 record

Rhode Island, Philadelphia, and New Jersey responded that the dailies that were greater than the annuals could be deleted. Maryland determined that they should be kept since the difference values were small. The records for the remaining S/L agencies were kept. This QA issue only occurred during processing of Version 1.

b. Responses from S/L agencies

Each S/L agency reviewed its "QA Summary Report" files and the S/L agency provided direction for correcting QA issues either in the QA Summary Report Excel files or via e-mail. The inventory was then revised to incorporate responses from each agency and the QA checks were run again to verify that the QA issues were addressed. If an agency responded to a QA issue by e-mail, the direction was recorded in the "QA Summary Report" file. The "QA Summary Report" file for each S/L agency was updated to document QA issues and resolution of issues associated with developing Versions 2 and 3 of the point source inventory. The "QA Summary Report" files for Version 3 are provided with this report in a separate zip file. The files in the zip file are organized in separate folders for each S/L agency. Each folder includes a separate Excel workbook file for the following QA checks if a QA issue existed:

- PM Augmentation QA Summary;
- Stack Parameter QA Summary;
- Stack Coordinates QA Summary;
- Stack Parameter and Coordinate Augmentation Summary;
- CEM Comparisons and Revisions; and
- Control Device/Efficiency Summary.

c. Gap Filling and Augmentation

The following discusses the augmentation procedures that were used to fill in missing data that were not supplied by the S/L agencies. The S/L agencies approved the procedures before they were applied. These procedures were applied after revising the inventory to address QA issues as directed by each S/L agency.

i. MANE-VU-Sponsored Inventories

MANE-VU prepared a 2002 NH_3 emissions inventory for cement kilns for SCCs 30500606 and 30500706 located in four MANE-VU states. Maryland chose to add one new facility 24013/0012 (state and county FIPS code/facility ID). New York chose to add the following three sites 36001/4010300016, 36001/4012400001, and 36111/3514800084. Maine and Pennsylvania chose not to add emissions from this inventory. The data for Maryland and New York were added to Version 1. These data were not changed in Versions 2 and 3 of the point source inventory.

ii. PM Augmentation

The PM augmentations process gap-fills missing PM pollutant complements. For example, if a S/L agency provided only PM10-PRI pollutants the PM augmentation process filled in the PM25-PRI pollutants. The steps in the PM augmentation process were as follows:

- Step 1: Initial QA and remediation of S/L provided PM pollutants;

- Step 2: Development of PM factor ratios based on factors from the Factor Information and REtrieval (FIRE) Data System, version 6.2, and the PM Calculator (EPA, 2003a; EPA, 2004c);
- Step 3: Implementation of the ratios developed in step 2.; and
- Step 4: Presentation of PM augmentation results to S/L agencies for review and comment.

An Access database (named *Reference Tables for PM Augmentation*) accompanies this document. This database contains the SCC Control Device Ratio table, the Emission Factors table, and Emission Factors Crosstab table discussed in Step 2. The Emission Factors Crosstab table contains the ratios developed from the Emission Factors table. The Emission Factors table contains detailed information on the emission factors used to develop the ratios. The PM Calculator ratio table can be provided upon request – it contains all possible combinations for SCC and Control Device types that are available in the PM Calculator. Ratios from the PM calculator were developed using a standard input of 100 TONS of uncontrolled PM-FIL emissions.

1. Initial QA and Remediation of PM Pollutants

S/L agencies were initially presented with files that detailed potential inconsistencies and missing information in their PM pollutant inventory. Inconsistencies in PM pollutants include the following:

- PM-PRI less than PM10-PRI, PM25-PRI, PM10-FIL, PM25-FIL, or PM-CON;
- PM-FIL less than PM10-FIL, PM25-FIL;
- PM10-PRI less than PM25-PRI, PM10-FIL, PM25-FIL or PM-CON;
- PM10-FIL less than PM25-FIL;
- PM25-PRI less than PM25-FIL or PM-CON;
- The sum of PM10-FIL and PM-CON not equal to PM10-PRI; and
- The sum of PM25-FIL and PM-CON not equal to PM25-PRI.

Potential missing information was summarized in a table which detailed the variety of cases provided by each S/L agency. For example, an S/L agency might have provided PM10-FIL and PM25-FIL for some processes, but provided only PM10-FIL for other processes.

S/L agencies were asked to review this information and provide corrections where possible. In general, corrections (or general directions) were provided in the case of the potential inconsistency issues. An example of a general direction provided by a S/L agency was to remove PM25-FIL where greater than PM10-FIL because the PM10-FIL was (in their particular case) known to be more reliable. In other cases, the agency-provided specific process-level pollutant corrections. If specific direction was not provided by the agency, zero PM pollutants were generally removed, or complements were set equal to the higher number.

2. Development of PM Factor Ratio

The primary deliverable of this step of the process was the development of a table keyed by SCC, primary control device, and secondary control device. This table is called the SCC Control Device Ratios table (see Table II-1). This table was filled according to the following steps:

- Ratios (both condensible and noncondensible) were added from FIRE for SCCs starting with 10* (external fuel combustion) and 20* (internal fuel combustion) where there was a direct match between the provided SCC, and primary and secondary control devices.

- Ratios (non-condensable) were added from the PM Calculator for SCCs starting with 10* and 20* where there was not a direct match between the provided SCC, and primary and secondary control devices. Condensible ratios were added from the PM Calculator based on the uncontrolled SCC for these SCCs. In some cases, it was necessary to map the SCC and control devices to the PM calculator to find a match for the noncondensible ratios. In other cases, it was necessary to map the SCC to FIRE to find a match for condensible ratios.

- For natural gas, process gas, and liquified petroleum gas (LPG) SCCs starting with 10* and 20*, it was assumed (based on FIRE emission factors) that the PM-PRI/PM10-PRI/PM25-PRI ratio was equal to 1. It was also assumed that the PM-FIL/PM10- FIL /PM25- FIL was equal to 1. Condensible ratios were calculated from uncontrolled FIRE emission factors for these SCCs. In some cases it was necessary to map the SCC to FIRE to find a match for condensible ratios.

- Ratios for SCCs not like 10* and 20* were obtained from the PM Calculator. It was assumed that the condensible component was zero.

Table II-1. Description of the Field Names and Descriptions for the SCC Control Device Ratios Table

Field Name	Field Description
PM Calculator	A “Yes” in this field indicates that at least some of the information was retrieved from the PM Calculator
FIRE	A “Yes” in this field indicates that at least some of the information was retrieved from the Emission Factors table. A “Condensible Ratios” in this field indicates that the condensible ratios factors were retrieved from this table.
Other	A field to indicate other sources as necessary.
SCC	Source category code from the S/L agency-provided data.
SCC_DESC	Description of source category code from the S/L agency-provided data.
maptoSCC	This field equals SCC unless the SCC provided was not found in the appropriate source table. In that case, the SCC was mapped using the closest available appropriate mapping choice.
maptoSCC_DESC	Description of the maptoSCC.
mapSCCNote	Any notes related to the mapping of the SCC. A “Yes” in this field indicates that the SCC was mapped.
PD	Primary device type from the S/L agency provided data.
PD_DESC	Description of the primary device (PD).
maptoPD	This field equals PD unless the PD provided was not found in the appropriate source table. In that case, the PD was mapped using the closest available appropriate mapping choice.
maptoPD_DESC	Description of the maptoPD.
mapPDNote	Any notes related to the mapping of the PD. A “Yes” in this field indicates that the PD was mapped.
SD	Secondary device type from the S/L agency provided data.
SD_DESC	Description of the secondary device (SD).
maptoSD	This field equals SD unless the SD provided was not found in the appropriate source table. In that case, the SD was mapped using the closest available appropriate mapping choice.
maptoSD_DESC	Description of the maptoSD.
mapSDNote	Any notes related to the mapping of the SD. A “Yes” in this field indicates that the SD was mapped.
PM-FIL/PM10-FIL	This field and the following are ratios calculated from emission factors found either in FIRE or the PM calculator.
PM-FIL/PM25-FIL	This field and the following are ratios calculated from emission factors found either in FIRE or the PM calculator.
PM-FIL/PM-PRI	This field and the following are ratios calculated from emission factors found either in FIRE or the PM calculator.
PM-PRI/PM10-PRI	This field and the following are ratios calculated from emission factors found either in FIRE or the PM calculator.
PM-PRI/PM25-PRI	This field and the following are ratios calculated from emission factors found either in FIRE or the PM calculator.
PM10-FIL/PM25-FIL	This field and the following are ratios calculated from emission factors found either in FIRE or the PM calculator.
PM10-PRI/PM25-PRI	This field and the following are ratios calculated from emission factors found either in FIRE or the PM calculator.
PM-CON/PM10-FIL	Condensible ratios were calculate from FIRE if available for 10* and 20* SCCs. If condensible ratios were not found in FIRE for 10* and 20* these ratios were set to zero.
PM-CON/PM10-PRI	Condensible ratios were calculate from FIRE if available for 10* and 20* SCCs. If condensible ratios were not found in FIRE for 10* and 20* these ratios were set to zero.
PM-CON/PM25-FIL	Condensible ratios were calculate from FIRE if available for 10* and 20* SCCs. If condensible ratios were not found in FIRE for 10* and 20* these ratios were set to zero.
PM-CON/PM25-PRI	Condensible ratios were calculate from FIRE if available for 10* and 20* SCCs. If condensible ratios were not found in FIRE for 10* and 20* these ratios were set to zero.
PM-CON/PM-FIL	Condensible ratios were calculate from FIRE if available for 10* and 20* SCCs. If condensible ratios were not found in FIRE for 10* and 20* these ratios were set to zero.
PM-CON/PM-PRI	Condensible ratios were calculate from FIRE if available for 10* and 20* SCCs. If condensible ratios were not found in FIRE for 10* and 20* these ratios were set to zero.
RPO Specific Note	Indicates SCC and control device combinations are in the RPO inventory.
Additional Notes	Any notes regarding assumptions about ratios.

3. Implementation of the QA Ratios

In order to calculate the additional PM pollutants based on the SCC Control Device ratio table developed in the above step, a crosstab table was created from the EM table based on the following fields:

- State FIPS
- County FIPS
- Tribal Code
- EU ID
- Process ID
- Start Date
- End Date
- Emission Type
- SCC
- Primary Device Type
- Secondary Device Type

The primary and secondary device type fields were added based on information from the CE table. If CE information was not available these fields were defaulted to 000 (“UNCONTROLLED”). In the few cases where there was a conflict between the control devices reported for the same process for PM pollutants (e.g., a PM10-PRI is listed as controlled, but PM-PRI did not have control information), the control device type was selected based on the controlled pollutant.

In addition to the fields listed above, the crosstab included the PM emission amounts for the particular process and a field that indicated whether those emissions existed in the inventory. These fields were as follows:

- PM_PRI
- PM_FIL
- PM10_PRI
- PM10_FIL
- PM25_PRI
- PM25_FIL
- PM_CON
- PM_PRI_EXISTS
- PM_FIL_EXISTS
- PM10_PRI_EXISTS
- PM10_FIL_EXISTS
- PM25_PRI_EXISTS
- PM25_FIL_EXISTS
- PM_CON_EXISTS

The emission values were in the PM_PRI, PM_FIL, PM10_PRI, PM10_FIL, PM25_PRI, PM25_FIL, PM_CON fields. The _EXISTS field indicated whether the pollutant was provided by the S/L agency. A zero indicated that the pollutant was not provided; a number greater than zero (usually one) indicates that it was provided by the S/L agency.

Prior to the development of this crosstab, the EM table was filled in as much as possible using basic assumptions. For example, if the S/L agency provided zero emissions for some but not all forms of PM for a particular process, it was assumed that all forms of PM for that process were zero and they were filled in accordingly. Since that assumption was that for non 10* and 20* SCCs, the condensible value was zero – that would lead to PM10-FIL = PM10-PRI and PM25-FIL = PM25-PRI and PM-FIL = PM-PRI. Given that assumption, values for these pollutants were also filled in. After this data insertion, a subset of the crosstab was created. This subset only contained processes that required additional augmentation. The SCC Control Device Type ratio table was based on only those SCC and control device types that required augmentation.

The next step was to fill in the missing information in this crosstab using the information found in the SCC Control Device Ratio table.

In calculating PM complement pollutants, priority was given to calculating –PRI and –CON pollutants. FIL pollutants were only calculated if necessary to calculate other pollutants or if it was a by-product of this calculation.

In augmenting the PM pollutants, the non 10* and 20* SCCs were augmented first, with order given to augmenting based on PM_{10} where available, $PM_{2.5}$ where available, and then PM.

Augmenting the PM pollutants for the 10* and 20* SCCs is more complicated, but the basic approach was to augment based on PM_{10} (FIL or PRI) where available, $PM_{2.5}$ (FIL or PRI) where available, and then PM (FIL or PRI) if PM_{10} or $PM_{2.5}$ variations were not available. Where both PM_{10} (FIL or PRI) and $PM_{2.5}$ (FIL or PRI) variations were both available, the calculation for PM-CON was generally driven from the PM_{10} number and the complements as necessary were back calculated. Where a PRI emission factor ratio was required and was not available, the FIL emission factor ratio was used.

After completing the calculations, the data was QA checked to ensure that the calculations resulted in consistent values for the PM complement. On a few occasions, the mix of ratio value and the pollutants and values provided by the S/L agency resulted in negative values when FIL was back-calculated. In this case the negative FIL value was set to zero and the PRI value was readjusted. In a few cases the appropriate combination of ratios, SCC, and control efficiencies were not available to calculate the PM10-PRI and PM25-PRI values. In these cases, PM10-PRI and PM25-PRI were set equal. The resultant PM table information was appended to the EM table.

Note: The augmentation procedures resulted in some high condensible ratios that were calculated for some SCC control device type combinations. In most cases, these high condensible ratios were the result of the back calculation of PM-CON from PMxx-PRI records.

Since the state had already provided the PMxx-PRI records, these PM-CON values were not added.

The data source code field was used to identify records that were added to the inventory to complete the set of PM10-PRI and PM25-PRI emissions.

iii. ERP Coordinates

If an S/L agency did not provide corrections for ERP coordinates that map more than 5 km outside of the county boundary, or provide coordinates for ERP records that did not have any coordinates in the S/L inventory, the following procedures were applied to replace the coordinates:

- Coordinates for other ERPs at the same facility, if available, that map within the county;
- Coordinates for the centroid of the zip code for a facility if a valid zip code was provided or could be obtained from the agency if it is not valid; or
- County centroid coordinates.

The zip code was taken from the SI NIF 3.0 table. The zip code was compared to a reference table of valid zip codes to verify that it was an active zip code and existed in the state and county reported in the inventory. If a valid zip code for a facility could not be identified, the centroid for the facility's county was used as a last resort. In some cases, the S/L agency provided confirmation that the S/L coordinates were correct even if the analysis indicated that the coordinates were outside of the county. These coordinates were not changed. Additionally, all coordinates were converted to latitude/longitude measurements.

iv. ERP Parameters

If valid ERP parameters were not provided by the S/L agency, the ERP augmentation procedures that EPA developed for the 2002 point source NEI were applied to the MANE-VU inventory (EPA, 2004b). It has been determined that the augmentation procedures in this document regarding SCC-specific ERP types and temperatures may be difficult to resolve. When this situation occurs, preference was given to the S/L agency -supplied ERP type and SCC. For example, the procedures do not account for cases where an EU has two processes with one defined as a stack source and the other as a fugitive source. Therefore, the S/L-supplied ERP type was used when this situation occurred. If the ERP type was null, and information was not available from the S/L agency, the stack height information was used as a guide. If stack height information was available, the ERP was treated as a stack, if stack height information was not available, the ERP was treated as a fugitive. An additional modification to the augmentation procedure was also implemented. Since in many cases null values were filled in with zeros by S/L local databases when comparing out-of-range velocities and flows (after it was determined that the stack and diameter information was correct) – null and zero values were treated in the same manner to prevent inappropriate replacement of stack parameter values. Additionally, stack parameter values were rounded to 1 decimal place when comparing with range values (just for the purposes of comparison) to prevent replacement of S/L parameter values based on negligible decimal differences.

v. Control Device Type and Control Efficiency Data

Control efficiencies that were 100% and rule effectiveness of 100% with non-zero emissions were diagnosed as potential errors and sent to the S/L agencies. Where possible these data were updated with S/L data corrections. Decimal control efficiencies were also diagnosed and sent to the S/L agencies. A decimal control efficiency was usually a sign that a control efficiency had not been entered as a percentage as is required by NIF 3.0. Where possible these data was updated with S/L data corrections.

c. QA Review of Final Inventory

Final QA checks were run on the revised point source inventory data set to ensure that all corrections provided by the S/L agencies were incorporated into the S/L inventories and that there were no remaining QA issues that could be addressed during the duration of the project. The EPA QA program was run on the inventory and the QA output was reviewed to verify that all QA issues that could be addressed were resolved. The QA output file was provided in an Access database along with Version 3 of the inventory.

3. Version 3 Emissions Summary

Table II-2 presents a State-level summary of the annual point source emissions in Version 3 of the 2002 MANE-VU inventory. Note that PM10-PRI and PM25-PRI emissions are included in the inventory for all SCCs for which S/L agencies reported any form of PM, PM_{10}, and/or $PM_{2.5}$ emissions. If an agency did not report PM10-PRI and/or PM25-PRI but reported PM-PRI, PM-FIL, PM-CON, PM10-FIL, and/or PM25-FIL, the PM augmentation procedures discussed in the TSD were applied to the form of PM emissions supplied by the agency to calculate emissions for the other forms of PM emissions. If an agency reported PM10-PRI and/or PM25-PRI emissions but not PM10-FIL, PM25-FIL, or PM-CON emissions, the agency's inventory was not augmented to calculate filterable or condensible emissions. Note that PM-CON is associated with only fuel combustion sources.

Table II-2. Version 3 2002 MANE-VU Point Source Emissions by State (Tons/Year)

State	CO	NH_3	NO_x	PM10-FIL	PM10-PRI	PM25-FIL	PM25-PRI	PM-CON	SO_2	VOC
Connecticut	4,053		12,923	738	1,617	0	1,283	389	15,988	4,907
Delaware	9,766	196	16,345	2,466	4,217	1,919	3,666	1,750	73,744	4,755
District of Columbia	248	4	780	91	161	54	132	68	963	69
Maine	17,005	845	19,939	4,535	7,289	2,567	5,787	2,753	23,711	5,319
Maryland	99,024	305	95,328	3,723	9,029	0	5,054	2,018	290,927	6,184
Massachusetts	21,262	1,463	47,086	2,776	5,852	997	4,161	2,984	101,049	8,263
New Hampshire	2,725	74	9,759	1,180	3,332	786	2,938	2,151	46,560	1,599
New Jersey	12,300		51,593	2,928	6,072	2,543	4,779	3	61,217	14,401
New York	66,427	1,861	118,978	1,808	10,392	1,965	7,080	210	294,729	11,456
Pennsylvania	121,524	1,388	297,379	18,044	40,587	6,038	20,116	5,065	995,175	37,323
Rhode Island	2,234	58	2,764	233	300	117	183	68	2,666	1,928
Vermont	1,078		787	130	304	97	267	2	905	1,097
MANE-VU	**357,645**	**6,194**	**673,660**	**38,654**	**89,150**	**17,083**	**55,447**	**17,462**	**1,907,634**	**97,300**

B. State-Specific Methods

For each of the MANE-VU states and two local agencies in Pennsylvania, this section identifies the temporal basis of the emissions included in Version 3 and discusses revisions incorporated into Version 3. In addition, this section also discusses the origin of each S/L agency's emissions included in Version 3. For each agency, a table is provided in Appendix A that lists the data source codes by SCC, emission type period, and pollutant. In addition, an electronic folder is provided for each S/L agency containing the QA Summary Reports prepared during Version 1 and other files documenting revisions included in Versions 2 and 3.

1. Connecticut

Connecticut's Version 3 point source inventory originates from Version 1 except for the following revisions that Connecticut provided for Version 2 and included in Version 3:

- Changed coordinates for AES Thames, Inc. in New London County to -72.3184, 41.4499 (FIPS code 09011, facility identifier 1544).

- Changed values for Hartford Steam (FIPS code 09003, facility identifier 3471), EU P0250, process 02 for summer daily values as follows: Changed actual throughput from 1934 E6FT3 to 1.934 E6FT3, CO summer daily emissions from 53.185 tons to 0.0532 tons, NO_x summer daily emissions from 255.288 tons to 0.1021 tons, and VOC summer daily emissions from 1.2569 tons to 0.0027 tons.

Table II-3 shows the emission type periods for which Connecticut provided emissions.

Table II-3. Connecticut 2002 Point, Version 3:
Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
NONANNUAL	20011201	20020228	27
NONANNUAL	20011201	20020228	29
NONANNUAL	20020601	20020831	27
NONANNUAL	20020601	20020831	29

Table A-1 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Connecticut provided the data for CO, NO_x, PM10-PRI, SO_2, and VOC. Connecticut did not provide any data for NH_3. Emissions for PM10-FIL, PM25-PRI, PM25-FIL, and PM-CON were calculated from the PM10-PRI emissions provided by Connecticut using the PM augmentation procedures.

2. Delaware

Delaware's Version 3 point source inventory originates from Version 1 except for some updates to ORIS Boiler IDs in the EU table that were incorporated into Version 2 and included in Version 3. Table II-4 shows the emission type periods for which Delaware provided emissions.

Table II-4. Delaware 2002 Point, Version 3:
Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
NONANNUAL	20020601	20020831	29

Table A-2 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Delaware provided the data for CO, NH_3, NO_x, SO_2, and VOC. Delaware also provided much of the PM emissions data but in some cases the PM augmentation procedures were applied to the PM data provided by Delaware to calculate emissions for other forms of PM (e.g., to estimate PM10-PRI from PM10-FIL, PM25-PRI from PM25-FIL, PM10-PRI and PM10-FIL from PM25-PRI and PM25-FIL).

3. District of Columbia

The District of Columbia's Version 3 point source inventory originates from Version 1. Table II-5 shows the emission type period for which the District of Columbia provided emissions.

Table II-5. District of Columbia 2002 Point, Version 3:
Unique List of Start Date, End Date, and Emission Type

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30

Table A-3 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. The District of Columbia provided the data for CO, NH_3, NO_x, SO_2, and VOC. The District of Columbia provided at least one form of PM emissions and the PM augmentation procedures were applied to the emissions provided by the District of Columbia to calculate emissions for the other forms of PM.

4. Maine

Maine's Version 3 point source inventory originates from Version 1. Table II-6 shows the emission type periods for which Maine provided emissions.

Table II-6. Maine 2002 Point, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
NONANNUAL	20020601	20020831	29

Table A-4 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Maine provided the emissions data for CO, NH_3, NO_x, SO_2, and VOC. Maine provided PM10-FIL and/or PM25-FIL emissions data and the PM augmentation procedures were applied to the emissions that Maine provided to calculate emissions for the other forms of PM.

5. Maryland

Maryland's Version 3 point source inventory originates from Version 1 except for some updates to ORIS Boiler IDs in the EU table that were incorporated into Version 2 and included in Version 3. Table II-7 shows the emission type periods for which Maryland provided emissions.

Table II-7. Maryland 2002 Point, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
ANNUAL	20040101	20041231	30
NONANNUAL	20020101	20021231	29
NONANNUAL	20020501	20020930	29
NONANNUAL	20040101	20041231	29

Table A-5 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Maryland provided the emissions data for CO, NH_3, NO_x, SO_2, VOC, PM10-PRI, and PM-PRI. The PM augmentation procedures were applied to the PM10-PRI emissions that Maryland provided to calculate emissions for the other forms of PM. Maryland provided NH_3 emissions for its point sources except for one new facility (state and county FIPS code 24013, facility ID 0012, SCC 30500622, data source code P) for which it used NH_3 emissions for four EUs (preheater kiln/dry process) prepared by MANE-VU.

6. Massachusetts

Massachusetts' Version 3 point source inventory originates from Version 1 except for the some stack parameter revisions that Massachusetts provided and were incorporated into Version 3. For Version 3, Massachusetts provided revisions to stack parameters in the ERP table for six EUs at three facilities. The revisions are listed in the Excel file named "MA Revisions to MANEVU V3 Point EI_040706.xls". Table II-8 shows the emission type periods for which Massachusetts provided emissions.

Table II-8. Massachusetts 2002 Point, Version 3:
Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
ANNUAL	20030101	20031231	30

Table A-6 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Massachusetts provided the emissions data for CO, NH_3, NO_x, SO_2, and VOC. Massachusetts provided PM-FIL, PM10-FIL, and/or PM25-FIL emissions data and the PM augmentation procedures were applied to the emissions that Massachusetts provided to calculate emissions for the other forms of PM.

7. New Hampshire

New Hampshire's Version 3 point source inventory originates from Version 1.
Table II-9 shows the emission type periods for which New Hampshire provided emissions.

Table II-9. New Hampshire 2002 Point, Version 3:
Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
NONANNUAL	20020601	20020831	29

Table A-7 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. New Hampshire provided the emissions data for CO, NH_3, NO_x, SO_2, and VOC. New Hampshire provided PM-FIL, PM10-FIL, and/or PM25-FIL emissions data and the PM augmentation procedures were applied to the emissions that New Hampshire provided to calculate emissions for the other forms of PM.

8. New Jersey

New Jersey's Version 3 point source inventory originates from Version 1. In addition to the QA checks discussed previously in this TSD, New Jersey's original inventory submittal to EPA contained several issues with SCCs. For Version 1, per direction provided by New Jersey, SCCs that were less than 8 digits were changed to SCCs with 8 digits. Also, as approved by New Jersey, inactive SCC 39999901 was changed to active SCC 39999999. The invalid unit "GAL" was changed to the valid unit "E6GAL" in the EP table.

Table II-10 shows the emission type periods for which New Jersey provided emissions.

Table II-10. New Jersey 2002 Point, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
NONANNUAL	20011201	20020228	29
NONANNUAL	20020601	20020831	29

Table A-8 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. New Jersey provided the emissions data for CO, NO_x, SO_2, and VOC. New Jersey provided PM-PRI, PM10-PRI, and/or PM25-PRI emissions data and the PM augmentation procedures were applied to the emissions that New Jersey provided to calculate emissions for the other forms of PM. New Jersey did not provide any data for NH_3.

9. New York

New York's Version 3 point source inventory originates from Version 1 except for the following revisions that New York provided and were incorporated into Version 3.

For Version 3, New York provided an Access database named "MANEVU_NY2002_ Point_Corrected_093005.mdb" with revisions to records in the EM table. New York also provided in this database 651 records that were not included in Version 2 of MANE-VU's point source inventory, and, therefore, these records were added to Version 3 of MANE-VU's point source inventory. The new records added emissions for pollutants (not in Version 2) for EUs and processes that existed in Version 2 of MANE-VU's point source inventory.

The records in Version 2 that were revised and the records that were added to Version 3 are listed in the Excel file named "NY Revisions to MANE-VU V3 Point EI_040706.xls".
Table II-11 shows the emission type period for which New York provided emissions.

Table II-11. New York 2002 Point, Version 3: Unique List of Start Date, End Date, and Emission Type

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30

Table A-9 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. New York provided the emissions data for CO, NH_3, NO_x, SO_2, and VOC. New York provided PM-PRI, PM10-PRI, and/or PM25-PRI emissions data and the PM augmentation procedures were applied to the emissions that New York provided to calculate emissions for the other forms of PM. New York provided NH_3 emissions for its point sources except for four cement kilns for which it used NH_3 emissions from a MANE-VU-sponsored inventory. The following identifies the facilities for which the MAEN-VU-sponsored NH_3 emissions inventory for cement kilns was used.

FIPS Code	Facility ID	SCC	Data Source
36001	4010300016	30500606 (2 kilns/dry process)	P
36001	4012400001	30500706 (1 kiln/wet process)	P
36111	3514800084	30500606 (1 kiln/dry process)	P

10. Pennsylvania (State, Excluding Allegheny and Philadelphia Counties)

The Version 3 point source inventory for the state of Pennsylvania originates from Version 1. The following summary excludes Allegheny and Philadelphia Counties who provided their own point source inventories for Versions 1, 2, and 3.

Table II-12 shows the emission type periods for which Pennsylvania provided emissions. Table A-10 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Pennsylvania provided the emissions data for CO, NH_3, NO_x, SO_2, and VOC. Pennsylvania provided PM10-PRI and/or PM25-PRI emissions data and the PM augmentation procedures were applied to the emissions that Pennsylvania provided to calculate emissions for the other forms of PM.

Table II-12. Pennsylvania 2002 Point, Version 3:
Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type	Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20020104	30	ANNUAL	20020131	20020812	30
ANNUAL	20020101	20020111	30	ANNUAL	20020131	20021231	30
ANNUAL	20020101	20020120	30	ANNUAL	20020201	20020228	30
ANNUAL	20020101	20020123	30	ANNUAL	20020201	20020424	30
ANNUAL	20020101	20020130	30	ANNUAL	20020201	20020831	30
ANNUAL	20020101	20020131	30	ANNUAL	20020201	20020930	30
ANNUAL	20020101	20020212	30	ANNUAL	20020201	20021030	30
ANNUAL	20020101	20020215	30	ANNUAL	20020201	20021130	30
ANNUAL	20020101	20020221	30	ANNUAL	20020201	20021231	30
ANNUAL	20020101	20020228	30	ANNUAL	20020205	20021223	30
ANNUAL	20020101	20020313	30	ANNUAL	20020213	20020913	30
ANNUAL	20020101	20020329	30	ANNUAL	20020214	20021231	30
ANNUAL	20020101	20020331	30	ANNUAL	20020216	20020331	30
ANNUAL	20020101	20020412	30	ANNUAL	20020301	20020331	30
ANNUAL	20020101	20020414	30	ANNUAL	20020301	20020430	30
ANNUAL	20020101	20020422	30	ANNUAL	20020301	20020531	30
ANNUAL	20020101	20020427	30	ANNUAL	20020301	20021031	30
ANNUAL	20020101	20020430	30	ANNUAL	20020301	20021130	30
ANNUAL	20020101	20020503	30	ANNUAL	20020301	20021231	30
ANNUAL	20020101	20020514	30	ANNUAL	20020311	20021213	30
ANNUAL	20020101	20020517	30	ANNUAL	20020311	20021231	30
ANNUAL	20020101	20020521	30	ANNUAL	20020314	20021209	30
ANNUAL	20020101	20020531	30	ANNUAL	20020318	20021223	30
ANNUAL	20020101	20020603	30	ANNUAL	20020320	20020915	30
ANNUAL	20020101	20020614	30	ANNUAL	20020320	20021231	30
ANNUAL	20020101	20020626	30	ANNUAL	20020328	20021120	30
ANNUAL	20020101	20020628	30	ANNUAL	20020330	20021122	30
ANNUAL	20020101	20020630	30	ANNUAL	20020401	20020430	30
ANNUAL	20020101	20020701	30	ANNUAL	20020401	20020531	30
ANNUAL	20020101	20020731	30	ANNUAL	20020401	20020731	30
ANNUAL	20020101	20020813	30	ANNUAL	20020401	20020930	30
ANNUAL	20020101	20020831	30	ANNUAL	20020401	20021231	30
ANNUAL	20020101	20020909	30	ANNUAL	20020409	20021205	30
ANNUAL	20020101	20020930	30	ANNUAL	20020415	20021117	30
ANNUAL	20020101	20021031	30	ANNUAL	20020415	20021231	30
ANNUAL	20020101	20021101	30	ANNUAL	20020421	20021024	30
ANNUAL	20020101	20021112	30	ANNUAL	20020424	20021016	30
ANNUAL	20020101	20021130	30	ANNUAL	20020428	20021231	30
ANNUAL	20020101	20021213	30	ANNUAL	20020429	20020922	30
ANNUAL	20020101	20021216	30	ANNUAL	20020429	20021031	30
ANNUAL	20020101	20021217	30	ANNUAL	20020501	20020630	30
ANNUAL	20020101	20021220	30	ANNUAL	20020501	20020930	30
ANNUAL	20020101	20021223	30	ANNUAL	20020501	20021013	30
ANNUAL	20020101	20021230	30	ANNUAL	20020501	20021031	30
ANNUAL	20020101	20021231	30	ANNUAL	20020501	20021231	30
ANNUAL	20020102	20020703	30	ANNUAL	20020506	20021202	30
ANNUAL	20020102	20021203	30	ANNUAL	20020511	20021231	30
ANNUAL	20020102	20021215	30	ANNUAL	20020515	20021231	30
ANNUAL	20020102	20021223	30	ANNUAL	20020519	20020727	30
ANNUAL	20020102	20021227	30	ANNUAL	20020525	20021231	30

Table II-12. (Continued)

Emission Type Period	Start Date	End Date	Emission Type	Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020102	20021228	30	ANNUAL	20020601	20020602	30
ANNUAL	20020102	20021229	30	ANNUAL	20020601	20020831	30
ANNUAL	20020102	20021230	30	ANNUAL	20020601	20020930	30
ANNUAL	20020102	20021231	30	ANNUAL	20020601	20021019	30
ANNUAL	20020103	20021126	30	ANNUAL	20020603	20021231	30
ANNUAL	20020103	20021228	30	ANNUAL	20020606	20021127	30
ANNUAL	20020103	20021231	30	ANNUAL	20020629	20021231	30
ANNUAL	20020104	20020930	30	ANNUAL	20020701	20020731	30
ANNUAL	20020104	20021223	30	ANNUAL	20020701	20020930	30
ANNUAL	20020104	20021231	30	ANNUAL	20020701	20021231	30
ANNUAL	20020105	20021218	30	ANNUAL	20020708	20021231	30
ANNUAL	20020105	20021231	30	ANNUAL	20020801	20020831	30
ANNUAL	20020106	20021231	30	ANNUAL	20020801	20020930	30
ANNUAL	20020107	20021231	30	ANNUAL	20020801	20021130	30
ANNUAL	20020108	20021221	30	ANNUAL	20020801	20021231	30
ANNUAL	20020108	20021228	30	ANNUAL	20020802	20021231	30
ANNUAL	20020110	20021204	30	ANNUAL	20020901	20020930	30
ANNUAL	20020111	20021231	30	ANNUAL	20020901	20021231	30
ANNUAL	20020113	20021006	30	ANNUAL	20020920	20021231	30
ANNUAL	20020114	20021203	30	ANNUAL	20021001	20021030	30
ANNUAL	20020115	20020318	30	ANNUAL	20021001	20021231	30
ANNUAL	20020115	20020323	30	ANNUAL	20021028	20021231	30
ANNUAL	20020115	20020326	30	ANNUAL	20021101	20021231	30
ANNUAL	20020115	20020830	30	ANNUAL	20021118	20021231	30
ANNUAL	20020123	20020127	30	ANNUAL	20021201	20021231	30
ANNUAL	20020124	20021127	30				

11. Pennsylvania (Allegheny County, FIPS code 42003)

The Version 3 point source inventory for Allegheny County, Pennsylvania originates from Version 1. Table II-13 shows the emission type periods for which Allegheny County provided emissions.

Table II-13. Pennsylvania - Allegheny County 2002 Point, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
NONANNUAL	20011201	20020228	29
NONANNUAL	20020601	20020831	29

Table A-11 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Allegheny County provided the emissions data for CO, NH_3, NO_x, SO_2, and VOC. Allegheny County provided PM-FIL, PM10-FIL, PM25-FIL, and/or PM-CON emissions data and the PM augmentation procedures were applied to the emissions that Allegheny County provided to calculate emissions for the other forms of PM.

12. Pennsylvania (Philadelphia County, FIPS code 42101)

The Version 3 point source inventory for Philadelphia County, Pennsylvania originates from Version 1. Table II-14 shows the emission type periods for which Philadelphia County provided emissions.

Table II-14. Pennsylvania - Philadelphia County 2002 Point, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
NONANNUAL	20011201	20020228	29
NONANNUAL	20020601	20020831	29

Table A-12 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Philadelphia County provided the emissions data for CO, NH_3, NO_x, SO_2, and VOC. Philadelphia County provided PM-FIL, PM10-FIL, and/or PM25-FIL emissions data and the PM augmentation procedures were applied to the emissions that Philadelphia County provided to calculate emissions for the other forms of PM.

13. Rhode Island

Rhode Island requested that their Version 2 inventory be replaced with the CAP and NH_3 inventory in the final 2002 point source NEI that EPA released during March 2006. Therefore, all of Rhode Island's point source data in Version 2 was replaced with the point source data provided in the final 2002 point source NEI. The following provides a summary of the QA issues identified and addressed in Version 1. The Excel file named "RI Revisions to MANE-VU V3 Point EI_040706.xls" provides documentation and correction of each of these issues for Version 3.

The Site table in the NEI did not include the ORIS IDs for all of the EGUs identified in the EGU crosswalk table. Therefore, the crosswalk table was used to add the ORIS IDs to the Site table. Matching of boiler IDs to the EU table for one facility was maintained in the NEI, and, therefore, included in Version 3 of MANE-VU's inventory. However, matching of boiler IDs for other facilities was not available in the crosswalk table.

The data source codes that EPA used in the Rhode Island's point source inventory for the NEI were maintained in the MANE-VU inventory. The following defines the codes:

Code	**Description**
A	Augmented PM data.
CAMD	Record only in 2002 Emission Tracking System (ETS)/CEM for SO_2, NO_x, and heat input values; other emissions estimated.
SCAMD1	Data were received from the state. The state's NO_x and SO_2 emission values were replaced with the ETS values.
99_PMPRI	Not defined – presumed to mean PM-PRI data originating from the 1999 NEI.
SUM	Primary PM emissions calculated as the sum of the filterable PM and PM-CON emissions
DIFF	PM-CON emissions calculated as the difference between the primary PM and filterable PM emissions

QA of PM emissions was also performed in accordance with the QAPP for the 2002 base year inventory for EM table records that were revised or added for Rhode Island and New York. As a result, it was identified that the emission ton value was not correctly calculated from the emission unit numerator and emission numeric value fields in the NEI file, therefore, the emission ton value was corrected for the MANE-VU inventory. In addition, the final NEI for Rhode Island contained NH_3 emissions for several facilities but no SCCs were provided for the NH_3 emissions; therefore, the NH_3 emissions were removed for the MANE-VU inventory as requested by Rhode Island.

For Version 3 of MANE-VU's inventory, Facility ID EGU1036 and Facility Name MANCHESTER STREET in the final 2002 NEI was changed to Facility ID AIR936 and Facility Name USGEN NEW ENGLAND INC per Rhode Island's request because this is the same facility (with ORIS ID 3236). Also, for State Facility ID AIR594, EU ID 2, ERP 2, and Process ID 2, the SCC was changed from 39000589 to 39000599. In addition, the ORIS IDs reported in the NEI were revised to make them consistent with the crosswalk prepared for MANE-VU that matches state facility IDs to ORIS IDs.

One issue was identified with one record for Rhode Island where the sum of the PM10-FIL and PM-CON emissions was more than the PM10-PRI emissions, and the sum of the PM25-FIL and PM-CON emissions was more than the PM25-PRI emissions for facility ID AIR1248 in County FIPS 44007; SCC 10300601 (External Combustion Boilers : Commercial/Institutional : Natural Gas : > 100 Million Btu/hr). In addition, the PM10-FIL emissions reported was 1.6 tons more than the PM10-PRI emissions reported, and the PM25-FIL emissions reported was 1.6 tons more than the PM25-PRI emissions reported for this facility. The record has very low emissions and it was not clear how the PM consistency issues should be addressed; therefore, due to time and resource constraints, this issue was not corrected in Version 3.

Table II-15 shows the emission type periods for which Rhode Island provided emissions.

Table II-15. Rhode Island 2002 Point, Version 3:
Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020601	20020831	29
NONANNUAL	20020601	20020831	29
NONANNUAL	20020601	20020831	30

Table A-13 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Rhode Island provided the emissions data for CO, NO_x, SO_2, VOC, and PM-PRI. The EPA applied PM augmentation procedures to the PM-PRI emissions that Rhode Island provided to calculate emissions for the other forms of PM. The EPA added NH_3 emissions for an EGU from EPA's CAMD data; otherwise, NH_3 emissions are not available for other point sources in Rhode Island.

14. Vermont

Vermont's Version 3 point source inventory originates from Version 1. Table II-16 shows the emission type periods for which Vermont provided emissions.

Table II-16. Vermont 2002 Point, Version 3:
Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
NONANNUAL	20020101	20020331	27
NONANNUAL	20020101	20021231	29
NONANNUAL	20020601	20020831	27

Table A-14 in Appendix A identifies the data sources by SCC, emission type period, and pollutant in the Version 3 point source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Vermont provided the emissions data for CO, NO_x, SO_2, and VOC. Vermont provided PM-FIL, PM10-FIL, and/or PM25-FIL emissions data and the PM augmentation procedures were applied to the emissions that Vermont provided to calculate emissions for the other forms of PM. Vermont's inventory does not include NH_3 emissions.

C. What Issues Need to be Addressed in Future Versions?

This section provides a summary of potential revisions to incorporate into future versions of the MANE-VU point source inventory.

All States – A coordinated effort between the S/L agencies should be developed to apply consistent methods to avoid having to apply procedures to augment inventory data to correct for the QA issues and fill in missing data as discussed previously in this chapter. For example, this will ensure that consistent methods are applied across S/L agencies to ensure accurate reporting of stack parameters, PM emissions, and minimize other QA issues that were identified during the development of Versions 1, 2, and 3 of the inventory.

For PM emissions, the S/L agencies should develop and apply a consistent method for including condensible emissions for fuel combustion sources that can be applied when the agencies develop their inventories. This may include compiling the emission factors for all forms of PM into one database, organized by SCC and control type (for filterable emissions), and sharing the database among the MANE-VU S/L agencies. Use of a consistent set of emission factors will help to avoid the PM consistency issues identified in Versions 1, 2, and 3 of the MANE-VU inventory as well as ensure that condensible emissions are included in the primary emissions reported in the inventory.

The EGU crosswalk should be maintained to ensure that State Facility IDs and EU IDs are correctly matched with ORIS IDs and boiler IDs.

State-specific suggestions are as follows:

Connecticut, New Jersey, Rhode Island, and Vermont – Include NH_3 emissions.

New Jersey – Develop a method to translate the SCCs that are less than 8 digits reported by facilities to 8 digit SCCs for reporting in the inventory.

CHAPTER III – AREA SOURCES

A. General Methods for all States

1. What Data Sources Were Used?

Version 1 of the 2002 MANE-VU area source inventory was built on the inventories that the State agencies submitted to EPA from May through July of 2004 as a requirement of the CERR. Except for Rhode Island, all of the MANE-VU States also submitted area source inventories to EPA. Rhode Island elected to use the preliminary 2002 NEI for its area source inventory. The EPA performed some limited QA review of the State inventories to identify format, referential integrity, and duplicate record issues. The EPA revised the inventories to address these issues and made the files available to the State agencies on August 6, 2004. These inventory files were used as the starting point for the MANE-VU inventory. These inventory files were obtained from EPA, consolidated into a single data set, subjected to extensive QA review, and revised (as approved by the MANE-VU State agencies) to address QA issues and fill data gaps identified while preparing Version 1. Subsequently, the following agencies provided revisions to their area source inventories:

- Version 2 – District of Columbia, Massachusetts, Maryland, New Hampshire, New Jersey, New York, and Vermont.

- Version 3 – Massachusetts, Maine, New Jersey, New York, and Rhode Island.

The Version 2 and 3 revisions for these States are discussed in section III.B (State-Specific Methods) of this chapter. In addition, as requested by MANE-VU, revisions were made to Version 3 to (1) add emissions for portable fuel containers (PFCs), industrial adhesives, and outdoor residential wood combustion for some States; (2) decrease the $PM_{2.5}$ emissions for paved and unpaved roads and construction for all States; and (3) remove invalid CE records that originated from the preliminary 2002 NEI for some States. These revisions are explained in section III.A.3 of this chapter.

To track the origin of data, the temporal period of emissions, and to facilitate generation of emission summaries, the following NIF plus fields were added to the EP, PE, EM, and CE tables:

- Data Source Codes:

For the area source inventory data, the data source codes are based on the following 9-character format:

[Data Origin]-[Year]-[Grown/Not Grown/Carried Forward]-[PM Augmentation Code]

Code	**Field Length**
Data Origin	1
Year	3 (including leading hyphen)
Grown/Not Grown/Carried Forward	2 (including leading hyphen)
PM Augmentation	3 (including leading hyphen)

Data Origin Codes

Code	Description
S	State agency-supplied data
L	Local agency-supplied data
R	Tribal agency-supplied data
P	Regional Planning Organization
E	EPA/Emission Factors and Inventory Group (EFIG)-generated data

Year Codes

Year for which data are supplied (e.g., Year = -02 for 2002), or from which prior year data are taken (e.g., Year = -99 for 1999; -01=2001).

Grown/Carried Forward/Not Grown Codes

Code	Description
-G	Used when emissions in a pre-2002 inventory are grown to represent 2002 emissions.
-F	Used when emissions in a pre-2002 inventory are carried forward and included in the 2002 inventory without adjustment for growth.
-X	Used when the emissions are not grown or are not carried forward. For example, X is used when emissions are calculated for the 2002 inventory using 2002 activity, or when data are replaced with 2002 State data.

PM Augmentation Codes

-PA	PM Augmented Emissions: Record for PM_{10}/$PM_{2.5}$ emissions that were updated or added using ad-hoc updates.
-PC	PM Augmented Emissions: Record added for PM_{10}/$PM_{2.5}$ emissions estimated using the PM Calculator.
-PR	PM Augmented Emissions: Record added for PM_{10}/$PM_{2.5}$ emissions estimated using ratios of PM_{10}-to-PM or $PM_{2.5}$-to-PM_{10}. If PM_{10} and $PM_{2.5}$ emissions are equal and one of the pollutants is assigned this code, the ratio is assumed to be 1.

- Revision Date: This field indicates the month and year during which the last revision was made to a record.

- State FIPS: This field indicates the State FIPS code of the submittal.

- County FIPS: This field indicates the county FIPS code of the inventory.

The following NIF plus fields were added to the EM table:

- Emission Ton Value: This field indicates the values of the emissions in tons. This field was used to prepare summaries of emissions on a consistent EU basis.

- Emission Type Period: This field indicates the period of the Emission Type – either ANNUAL, SEASONAL, MONTHLY, or DAILY. Emission table records designated as ANNUAL were used to prepare summaries of annual emissions.

- CAP_HAP: This field identifies records for CAP versus records for HAPs. For the MANE-VU inventory, the flag is CAP for all records.

- Year: This field indicates the year of the data; for this inventory, it is 2002.

2. What Quality Assurance Steps Were Performed?

A QAPP was prepared and approved by MANE-VU/MARAMA and the EPA Regional Office prior to initiating work on Version 1 of the inventory (MANE-VU, 2004a). This QAPP was followed during preparation of all three versions of the inventory. This section provides an overview of the QA checks completed on each version of the inventory. The QA process for each State inventory involved the following steps that are also included in the following discussion:

- Conduct QA checks on each State inventory;
- Prepare a QA Summary Report for submittal to the agency for review;
- Revise the inventory to resolve QA issues as directed by the agency;
- Repeat the QA checks on the revised inventory to verify that the corrections were completed;

- Perform augmentation to correct for missing data; and
- Repeat the QA checks to verify that the augmentation was completed correctly.

a. QA checks for State emission inventories

The following QA checks were run on each State inventory:

i. County and SCC coverage
ii. Pollutant coverage
iii. EPA QA summaries sent to State agencies
iv. Range errors
v. PM emissions consistency and completeness review
vi. Control device type and control efficiency data review
vii. Start and end date checks
viii. Annual and daily emissions comparison

County and SCC Coverage

The county coverage in the State inventories appeared to be reasonable for all States. The SCC coverage was difficult to evaluate simply by showing a count of the number of SCCs by State. Each State inventory was compared to the preliminary 2002 NEI, and area source categories in the NEI but not in a State inventory were sent to each agency for review. Each State agency then selected the NEI categories that were then added to the MANE-VU inventory.

Pollutant Coverage

The pollutant coverage in the State inventories was complete for all pollutants except for PM_{10} and $PM_{2.5}$. Diagnosis and resolution of PM_{10} and $PM_{2.5}$ pollutant emissions is discussed later in section III.A.2.c. The exception was Connecticut who included only VOC, NO_x, and CO emissions in its inventory submittal to EPA.

EPA QA Summaries Sent to State Agencies

Under a separate project with EPA, Pechan performed QA review of the State area source inventories. This QA review involved running EPA's QA program on each data set to identify and resolve QA issues. Using the results of this QA work, Pechan prepared two sets of QA summaries that EPA sent to the State agencies. Pechan contacted each State agency with QA issues identified in the EPA reports to obtain direction for correcting the QA issues identified in the reports. The following explains these two summaries:

High-level Summary of State Inventories Submitted to EPA:

The first summary was an Excel workbook file with four spreadsheets that provided the following information:

- 2002 Nonpoint File Names: This spreadsheet documented names and formats of the files that EPA received from the State agencies and the dates on which they were transferred to Pechan.

- 2002 Nonpoint Summary: This spreadsheet documented the name of the state agency, type of inventory (i.e., CAP, HAP, or both), a comparison of the number of the counties in the inventory to the total number of counties in the State to identify the geographic coverage of the inventory, a unique list of CAP codes, and the total number of area source SCCs. This spreadsheet also indicated if any nonroad or onroad emissions data were moved from the agency's area source inventory to its nonroad or onroad inventory.

- 2002 Nonpoint Emission Sums: This spreadsheet summarized emissions by start date, end date, and emission type and assigned the appropriate code to the emission type period NIF plus field.

- 2002 Nonpoint Error Summary: This spreadsheet provided a copy of the "SummaryStats" table from the EPA QA program (EPA, 2004a). This table provided the count of records for each NIF 3.0 table and identified the number of records with errors by type of error.

Detailed Summary of QA Issues:

This summary (sent to State agencies on August 11) was prepared in a text file that listed by State and NIF table the number of records with errors, and provided corrections for the errors. To support documentation of corrections to some of the errors in the text file, Pechan prepared an Excel workbook file that summarized the following errors and corrections by State: invalid pollutants codes; invalid units; invalid maximum achievable control technology (MACT) codes; and invalid and inactive SCCs. A spreadsheet was also included to show the mapping of standard industrial classification (SIC) codes to North American Industrial Classification System (NAICS) codes. This crosswalk was used to correct invalid NAICS codes if a valid SIC code was available in the State inventories and vice versa.

Additional QA for the MANE-VU Area Source Inventory

The following explains additional QA and data tracking that was performed for the MANE-VU inventory. The following data elements were reviewed to identify QA issues:

- Range Errors;
- PM Emissions Consistency and Completeness;
- Control Device Codes and Control Efficiency Values;
- Start and End Dates;
- Annual and Daily Emissions Comparison; and
- Comparison of State Inventories to the 2002 Preliminary NEI.

For each State inventory for which QA issues were identified, a separate QA Summary Report was prepared in an Excel workbook file, and sent to each State agency for review. The State agencies provided directions in the Excel Workbook file, via e-mail, or by submitting revised records in NIF 3.0 in an Access database to correct the inventories. The QA reports are discussed under section III.A.2.b.

Range Errors

The EPA's QA program contains routines that compare annual emission values, numeric fields in the PE and EP tables, and other temporal numeric fields against a range of values. The QA program flags records that are less than or greater than the range of values for review. Pechan summarized the range errors for the State agencies to review and provide corrections. According to EPA, the ranges to which values in inventories are compared represent "normal" ranges that are based on percentiles from previous inventories. The range values are conservative in that EPA wants to identify suspicious values even though the values may be real (Thompson, 2002).

PM Emissions Consistency and Completeness Review

The following consistency checks were performed at the EM table data key level (for annual emissions) to compare PM emissions:

- If an SCC was associated with a PM emission record, but was missing one or more of the following (as appropriate for the SCC [i.e., PM-CON is associated with fuel combustion only]): PM10-FIL, PM10-PRI, PM25-FIL, PM25-PRI, or PM-CON, the record was flagged for review.

- The following equations were used to determine consistency:

  PM10-FIL + PM-CON = PM10-PRI
  PM25-FIL + PM-CON = PM25-PRI

- The following comparisons were made to determine consistency:

  PM10-PRI >= PM10-FIL
  PM25-PRI >= PM25-FIL
  PM10-PRI >= PM-CON
  PM25-PRI >= PM-CON
  PM10-FIL >= PM25-FIL
  PM10-PRI >= PM25-PRI

If the data failed one of these checks it was diagnosed as an error. If a State agency did not provide corrections to these errors, the errors were corrected/filled in according to an augmentation procedure explained in section III.A.2.c.

For information purposes, all PM-PRI and PM-FIL records were flagged to indicate that these pollutants were included instead of, or in addition to, the standard PM10-PRI/FIL, PM25-PRI/FIL, and PM-CON pollutants.

Control Device Type and Control Efficiency Data Review

The CE codes in the “Primary Device Type Code” and “Secondary Device Type Code” fields were reviewed to identify invalid codes (i.e., codes that did not exist in the NIF 3.0 reference table) and missing codes (e.g., records with a null or uncontrolled code of 000 but with control efficiency data).

QA review of control efficiency data involved diagnosis of two types of errors. First, records were reviewed to identify control efficiency values that were reported as a decimal rather than as a percent value. Records with control efficiencies with decimal values were flagged as a potential error (although not necessarily an error, since the real control efficiency may be less than 1%). Records with a 1% control efficiency value were also identified for review by the State agency to determine if the value was reported as a decimal in its internal data system but rounded to 1% when the data were converted to NIF 3.0.

The second check identified records where 100% control was reported in the CE table, but the emissions in the EM table were greater than zero and the rule effectiveness value in the EM table was null, zero, or 100% (implying 100% control of emissions). Because many agencies did not populate the rule effectiveness field or a default value of zero was assigned, records with null or zero rule effectiveness values were included where the CE was 100% and emissions were greater than zero. For records that met these criteria, Pechan consulted with the State agency to determine if corrections were needed to any of the fields.

Start and End Date Checks

QA review was conducted to identify start and end date values in the PE and EM tables to confirm consistency with the inventory year in the TR table, and to confirm that the end date reported was greater than the start date reported.

Annual and Daily Emissions Comparison

The State inventories were reviewed to determine if any of the following conditions existed:

- Multiple records coded at the SCC level as emission type 30, but with different start and end dates. While not a true duplicate, this may indicate an error or inclusion of both annual and seasonal values.
- Multiple records coded at the SCC level as a daily emission type (27, 29, etc.) but with different start and end dates. While not a true duplicate, this may indicate an error or just inclusion of additional types of daily emissions.
- Multiple records coded at the SCC level with the same start and end date, but different emission types. While not a true duplicate, this may indicate an error or just inclusion of additional types of daily emissions.
- Any "DAILY" type record that was missing its associated "ANNUAL" record was flagged for review.
- Any "DAILY" type record that was greater than its associated "ANNUAL" record was flagged for review.

b. Responses from State Agencies

QA Summary Reports were sent to the State agencies to review the QA issues identified. The State agencies were asked to return these reports to MANE-VU with their corrections documented in the reports. These reports were then used to document revisions to the State inventories. The QA Summary Reports containing the revisions provided by the State agencies are provided in Excel Workbook files with this TSD.

c. Gap Filling and Augmentation

This section explains the methods used to add data for categories and/or pollutants missing in a State's inventory after revising the inventory to address QA issues.

i. MANE-VU sponsored inventories
ii. PM augmentation
iii. Fossil fuel combustion sources
iv. Other sources of PM emissions
v. Merging of NEI data into S/L inventories
vi. Revisions to the preliminary 2002 NEI incorporated into Version 1 of the MANE-VU inventory
vii. Additional work on Area source methods
  - Fugitive Dust Emissions from Paved and Unpaved Roads
  - Wildfires and Prescribed Burning

The following discusses the augmentation procedures that were applied to the State inventories to improve the inventories or to fill in missing data not supplied by the State agencies.

MANE-VU -Sponsored Inventories

MANE-VU sponsored inventory development for residential wood combustion, open burning, public owned treatment works (POTWs), compositing, and industrial refrigeration. At the beginning of the project for developing Version 1, each State agency was requested to indicate if it (1) included the MANE-VU-sponsored inventory for one or more of these categories in the inventory it submitted to EPA; (2) included its own estimates for a category in the inventory it submitted to EPA; or (3) if it did not include a category in its inventory, if the MANE-VU-sponsored inventory or the 2002 preliminary NEI should be used as the source of data for the category. The results of this Version 1 inventory development request are summarized in Table III-1.

Improvements to fugitive dust emissions for the paved and unpaved road categories were completed after the draft version of the consolidated area source inventory was prepared. Agencies provided guidance on if they wanted the MANE-VU-sponsored inventory for these two categories to replace the paved and unpaved road inventories they had included in their inventories. For paved roads, all States requested that the MANE-VU-sponsored inventory be used; however, New Jersey and Maryland requested that the winter-time sand/silt adjustment not be included in their inventories. For unpaved roads, nine of the 12 States requested that the MANE-VU-sponsored inventory be used. New Jersey requested that its unpaved road inventory be used instead of the MANE-VU-sponsored inventory. In addition, the District of Columbia and Delaware do not have any unpaved road activity and excluded this category from their inventories.

PM Augmentation

Procedures were developed to estimate missing pollutant data from data provided by the State agencies in order to develop a complete set of PM10-PRI and PM25-PRI emissions to support air quality modeling. The following discusses the procedures for fossil fuel combustion sources first followed by the procedures for all other area sources of PM emissions.

Fossil Fuel Combustion Sources

Fossil fuel combustion sources include industrial, commercial/institutional, and residential anthracite coal, bituminous/subbituminous coal, distillate oil and kerosene, residual oil, natural gas, and LPG. All of these sources emit both filterable and condensible emissions. The QA review of the PM emissions data for these sources focused on verifying that the emissions reported in the State inventories included both filterable and condensible emissions. The emissions for these pollutants can be reported in State inventories individually (i.e., as filterable and condensible separately) or as primary emissions (i.e., the sum of the filterable and condensible emissions). The QA review also focused on evaluating the emission factors reported in the State inventories to determine if they were reasonable.

Table III-1. Summary of MANE-VU-Sponsored Inventories Included in Version 1 of the Area Source Consolidated Emissions Inventory

Area Source Category	Pollutant	SCCs	MANE-VU Inventory Included in State's Inventory Submitted to EPA			Not Included in State's Inventory - Add to MANE-VU Inventory			State's Inventory Includes State-Developed Estimates			Not Included in State's Inventory - Add 2002 Preliminary NEI Data to State's Inventory
			Annual	Summer Day	Winter Day	Annual	Summer Day	Winter Day	Annual	Summer Day	Winter Day	Annual
POTWs	NH_3, VOC	2630020010 (Wastewater Treatment)	DE, NJ, PA	DE, NJ, PA	▨	VT	VT	▨	CT, DC, DE, MA, MD, NH, NJ, NY	CT, DC, DE, MA, MD, NH, NJ	NJ	ME, RI
		2630020020 (Biosolids Processes)	DE, NJ, PA	DE, NJ, PA	▨	VT	VT	▨	CT, DC, DE, MA, MD, NH, NJ, NY	CT, DC, DE, MA, MD, NH, NJ	NJ	ME, RI
		2630050000 (Digested Sludge)	DE, NH, NJ, PA	DE, NH, NJ, PA	▨		VT	▨	CT, DC, DE, MA, MD, NY	CT, DC, DE, MA, MD	▨	ME, RI
Composting	NH_3, VOC	2680001000 (Biosolids)	NH, NJ	NH, NJ	▨ VT	CT, DC, MA, ME, PA, VT	CT, DC, MA, ME, PA, VT	▨			▨	
		2680002000 (Mixed Biosolids and Green Waste)	NH, NJ	NH, NJ	▨	CT, DC, MA, ME, PA, VT	CT, DC, MA, ME, PA, VT	▨			▨	
		2680003000 (Composting; Green Waste)			▨	DC, MA, ME	DC, MA, ME	▨			▨	
Industrial Refrigeration	NH_3	2399010000	ME, NH, NJ	ME, NH, NJ	▨	CT, MA, PA, VT	CT, MA, PA, VT	▨			▨	
Residential Wood Combustion	All criteria pollutants/ precursors, and many toxic air pollutants	2104008000 (Indoor)	MA, MD, NH	MA, MD, NH	MA, MD, NH	CT, DE, ME	CT, DE, ME	CT, DE, ME	NJ, NY, VT	NJ	NJ	DC, PA, RI
		2104008070 (Outdoor)	MA, MD, NH	MA, MD, NH	MA, MD, NH	CT, DE, ME	CT, DE, ME	CT, DE, ME				
Open Burning	All criteria pollutants/ precursors, and many toxic air pollutants	2610000100 (Leaves)	MA, MD, NH, PA	▨	▨	DC, DE, NY, VT	▨	▨	NJ	NJ	NJ	ME, RI
		2610000400 (Brush)	MA, MD, PA	▨	▨	CT, DC, DE, NY, VT	▨	▨	NJ	NJ	NJ	ME, NH, RI
		2610030000 (Municipal Solid Waste)	MA, MD, PA	▨	▨	DC, DE, NY	▨	▨	NH, NJ	NH, NJ	NJ	ME, RI, VT
		2610040400 (Municipal Yard Waste)	MA, NY, PA	▨	▨	DC, NY, VT	▨	▨	DE, NJ	DE, NJ	DE, NJ	

Table III-1 (continued)

Notes:

Gray shading identifies categories for which daily emissions are not available.

POTWs:

CT, MD: Provided VOC but not NH_3 emissions in its State inventory.

DC, MA, MD, ME, NH, RI: Reported POTW emissions under SCC 2630020000 (Total Processed).

DE: MANE-VU inventory used for NH_3; DE provided its own VOC emissions under SCC 2630020000 (Total Processed).

NJ: MANE-VU-sponsored inventory used for NH_3 only. NJ included its own inventory for the other criteria pollutants under SCCs 2630010000 and 2630020000.

NY: Reported VOC emissions under SCC 2630000000 (from the preliminary 2002 NEI) and SCC 2630020000 (State-developed inventory). MANE-VU-sponsored NH_3 inventory was not used.

Composting:

CT, NH: SCC 2680003000 is not in the MANE-VU-sponsored composting inventory for these States.

DE: This State does not have composting activity.

MD: State requested that the MANE-VU inventory for this category not be included in its inventory.

NY, RI: Did not include emissions for this category in the 2002 inventory.

Industrial Refrigeration:

DC: Requested that the preliminary 2002 NEI be used but the NEI does not contain any emissions for this category in DC.

DE: State-developed emissions are included in point source inventory.

MD, RI: Did not include emissions for this category in its inventory.

ME: Used the MANE-VU inventory emissions under SCC 2302080002 (Miscellaneous Food and Kindred Products/Refrigeration).

NH: Original inventory submittal to EPA includes SO_2 and PM emissions for SCC 2399000000 from the preliminary 2002 NEI; NH_3 emissions for SCC 2399010000 are from the MANE-VU inventory.

NY: Original inventory submittal to EPA includes SO_2 and PM emissions for SCC 2399000000 from the preliminary 2002 NEI; NY did not use the MANE-VU-sponsored NH_3 inventory for SCC 2399010000.

Residential Wood Combustion:

DC: RWC inventory in 2002 NEI covers seven SCCs and does not include daily emissions.

Open Burning:

CT: Statewide activity for SCC 2610000100 (Leaves) and SCC 2610030000 (Municipal Solid Waste) is negligible.

For SCCs 2610000400 (Brush) and 2610040400 (Municipal Yard Waste), State initially provided VOC, NO_x, and CO emissions under SCC 2610000000 which is no longer a valid SCC in EPA's master SCC list. CT recalculated emissions to include VOC, NO_x, CO, PM10-PRI/-FIL, and PM25-PRI/-FIL, and placed the emissions on valid SCC 2610000500 (Land Clearing Debris) since the majority of the activity is associated with activities covered by this SCC.

MD: The MANE-VU inventory for SCC 2610040400 (Municipal Yard Waste) reports zero emissions indicating that the activity for the category does not occur in MD. MD did not include the SCC in its inventory for this reason.

NH: Did not include NH_3 emissions in MANE-VU inventory for SCC 2610040400 (Municipal Yard Waste).

To support the QA review effort, the uncontrolled PM emission factors shown in Table III-2 were compiled from AP-42. The emission factors reported in the State inventories were compared to the emission factors in this table. Emission factors that appeared too high or too low were flagged for review by the State agency. In addition, inventory data were flagged for review by the State agency if the emissions were reported under the primary PM pollutant codes but the emission factors matched with the emission factors for filterable PM in Table III-2. Finally, if emission factors were not reported in the State agency inventory, the emission factors were back-calculated using the throughput data (if available), emissions, rule effectiveness values, and control efficiency data (if available). The back-calculated emission factors were compared to the factors in Table III-2 to identify data with major difference between the factors. It is emphasized that the uncontrolled emission factors in Table III-2 were used as a reference for reviewing State inventory data. The emission factors in this table should not be construed to be the best available for all State agencies since the emission factors will vary depending on the composition of the boiler population in an agency's area source inventory.

Delaware, Massachusetts, Maryland, New Hampshire, New Jersey, New York, and Pennsylvania provided their own inventory for all fossil fuel combustion categories. Connecticut, the District of Columbia, Maine, Rhode Island, and Vermont used fossil fuel combustion inventory data in the preliminary 2002 NEI for some or all of the categories. The following provides details on the origin of the fossil fuel combustion inventories for these States:

> Connecticut supplied VOC, NO_x, and CO emissions from its 1999 inventory for industrial and commercial/institutional fossil fuel combustion. PM10-PRI, PM25-PRI, SO_2, and NH_3 emissions were taken from preliminary NEI estimates (carried forward from Version 3 of the 1999 NEI). For the residential sector, Connecticut's inventory was taken from the preliminary 2002 NEI. Connecticut provided guidance on the counties with natural gas and LPG activity for which to use the NEI estimates.
>
> For the District of Columbia, the preliminary NEI was used to gap fill missing PM10-PRI and PM25-PRI emissions for commercial/institutional bituminous/ subbituminous coal combustion and PM10-PRI, PM25-PRI, SO_2, and NH_3 for commercial/institutional natural gas combustion. The NEI estimates for these commercial/institutional categories were carried forward from Version 3 of the 1999 NEI. The District of Columbia used the NEI estimates for residential bituminous/subbituminous coal combustion.
>
> Maine and Rhode Island used the preliminary 2002 NEI for all three sectors. The NEI estimates for the industrial and commercial/institutional sectors were carried forward from Version 3 of the 1999 NEI, while the residential sector estimates are based on 2000 or 2002 activity estimates prepared by EPA.
>
> Vermont used the preliminary 2002 NEI for the industrial and commercial/ institutional sectors and residential anthracite coal (carried forward from Version 3 of the 1999 NEI), but provided its own inventory for residential distillate oil, natural gas, and LPG.

Table III-2. Area Source Industrial, Commercial/Institutional, and Residential Fossil Fuel Combustion Uncontrolled Emission Factors for PM10-PRI/FIL, PM25-PRI/FIL, and PM-CON

Pollutant1	Uncontrolled Emission Factor (EF)	EF Numerator	EF Denominator	Calculated Uncontrolled EF	Reference
Industrial Boilers: Anthracite Coal (SCC 2102001000)					
PM10-FIL	2.3 x % Ash content of coal	LB	TON	30.77	AP-42 Table 1.2-4 EF calculated from formula of 2.3 * % Ash Content (13.38%). Reference for ash content is EPA, 2002.
PM25-FIL	0.6 x % Ash content of coal	LB	TON	8.03	AP-42 Table 1.2-4 EF calculated from formula of 0.6 * % Ash Content (13.38%) (used Commercial/Institutional emission factors). Reference for ash content is EPA, 2002.
PM-CON	0.08 x % Ash content of coal	LB	TON	1.07	AP-42 Table 1.2-3 Used formula for SCC 10300101, EF calculated from formula of .08 * % Ash Content (13.38%). Reference for ash content is EPA, 2002.
PM10-PRI		LB	TON	31.84	
PM25-PRI		LB	TON	9.10	
Industrial Boilers: Bituminous/Subbituminous Coal (SCC 2102002000)					
PM10-FIL	13.2	LB	TON	13.2	AP-42 Table 1.1-9 EF (used Commercial/Institutional emission factors)
PM25-FIL	4.6	LB	TON	4.6	AP-42 Table 1.1-9 EF (used Commercial/Institutional emission factors)
PM-CON	1.04	LB	TON	1.04	AP-42 Table 1.1-5 (used Commercial/Institutional emission factors)
PM10-PRI		LB	TON	14.24	
PM25-PRI		LB	TON	5.64	
Industrial Boilers and IC Engines: Distillate Oil (SCC 2102004000)					
PM10-FIL	1	LB	E3GAL	1	AP-42 Table 1.3-6
PM25-FIL	0.25	LB	E3GAL	0.25	AP-42 Table 1.3-6
PM-CON	1.3	LB	E3GAL	1.3	AP-42 Table 1.3-2
PM10-PRI		LB	E3GAL	2.30	
PM25-PRI		LB	E3GAL	1.55	
Industrial Boilers: Residual Oil (SCC 2102005000)					
PM10-FIL	7.17 x % Sulfur content of oil	LB	E3GAL	10.683	AP-42 Table 1.3-5. EF calculated from formula of 7.17(A); where A=1.12(S)+0.37; Assumed S=1% for purpose of calculating EF ratios.
PM25-FIL	4.67 x % Sulfur content of oil	LB	E3GAL	6.958	AP-42 Table 1.3-5. EF calculated from formula of 7.17(A); where A=1.12(S)+0.37; Assumed S=1% for purpose of calculating EF ratios.
PM-CON	1.5	LB	E3GAL	1.5	AP-42 Table 1.3-2
PM10-PRI		LB	E3GAL	12.18	
PM25-PRI		LB	E3GAL	8.46	
Industrial Boilers and IC Engines: Natural Gas (SCC 2102006000)					
PM10-FIL	1.9	LB	E6FT3	1.9	AP-42 Table 1.4-2
PM25-FIL	1.9	LB	E6FT3	1.9	AP-42 Table 1.4-2
PM-CON	5.7	LB	E6FT3	5.7	AP-42 Table 1.4-2
PM10-PRI	7.6	LB	E6FT3	7.60	
PM25-PRI	7.6	LB	E6FT3	7.60	

Table III-2 (continued)

Pollutant1	Uncontrolled Emission Factor (EF)	EF Numerator	EF Denominator	Calculated Uncontrolled EF	Reference
Industrial Boilers - Liquified Petroleum Gas (SCC 2102007000)					
PM10-FIL	0.6	LB	E3GAL	0.6	AP-42 Table 1.5-1
PM25-FIL	0.6	LB	E3GAL	0.6	AP-42 Table 1.5-1
PM-CON	0.506	LB	E3GAL	0.506	Used natural gas PM-CON emission factor of 5.7 lb/Million Cubic Feet (for all PM controls and uncontrolled). Used factor of 0.0887 to convert emission factor from lb/Million Cubic Feet of natural gas to lb/1,000 gallons of propane. Reference: AP-42, Table 1.4-2. Conversion factor assumes 1020 Btu/scf for natural gas (AP-42, Table 1.4-2) and 90,500 Btu/gallon for propane (AP-42, Appendix A, page A-5).
PM10-PRI		LB	E3GAL	1.11	
PM25-PRI		LB	E3GAL	1.11	
Industrial Boilers: Kerosene (SCC 2102011000)					
PM10-FIL	1	LB	E3GAL	1	AP-42 Table 1.3-6
PM25-FIL	0.25	LB	E3GAL	0.25	AP-42 Table 1.3-6
PM-CON	1.3	LB	E3GAL	1.3	AP-42 Table 1.3-6
PM10-PRI		LB	E3GAL	2.30	
PM25-PRI		LB	E3GAL	1.55	
Commercial/Institutional Heating: Anthracite Coal (SCC 2103001000)					
PM10-FIL	2.3 x % Ash content of coal	LB	TON	30.77	AP-42 Table 1.2-4 EF calculated from formula of 2.3 * % Ash Content (13.38%). Reference for ash content is EPA, 2002.
PM25-FIL	0.6 x % Ash content of coal	LB	TON	8.03	AP-42 Table 1.2-4 EF calculated from formula of 0.6 * % Ash Content (13.38%). Reference for ash content is EPA, 2002.
PM-CON	0.08 x % Ash content of coal	LB	TON	1.07	AP-42 Table 1.2-3 Used formula for SCC 10300101, EF calculated from formula of 0.08 * % Ash Content (13.38%). Reference for ash content is EPA, 2002.
PM10-PRI		LB	TON	31.84	
PM25-PRI		LB	TON	9.10	
Commercial/Institutional Heating: Bituminous and Lignite (SCC 2103002000)					
PM10-FIL	13.2	LB	TON	13.2	AP-42 Table 1.1-9 EF
PM25-FIL	4.6	LB	TON	4.6	AP-42 Table 1.1-9 EF
PM-CON	1.04	LB	TON	1.04	AP-42 Table 1.1-5 (0.04 lb/MMBtu * 26MMBtu/ton=1.04)
PM10-PRI		LB	TON	14.24	
PM25-PRI		LB	TON	5.64	
Commercial/Institutional Heating: Distillate Oil (SCC 2103004000)					
PM10-FIL	1.08	LB	E3GAL	1.08	AP-42 Table 1.3-7
PM25-FIL	0.83	LB	E3GAL	0.83	AP-42 Table 1.3-7
PM-CON	1.3	LB	E3GAL	1.3	AP-42 Table 1.3-2
PM10-PRI		LB	E3GAL	2.38	
PM25-PRI		LB	E3GAL	2.13	

Table III-2 (continued)

Pollutant[1]	Uncontrolled Emission Factor (EF)	EF Numerator	EF Denominator	Calculated Uncontrolled EF	Reference
Commercial/Institutional Heating: Residual Oil (SCC 2103005000)					
PM10-FIL	5.17 x % Sulfur content of oil	LB	E3GAL	7.703	AP-42 Table 1.3-7. EF calculated from formula of 5.17(A); where A=1.12(S)+0.37; Assumed S=1% for purpose of calculating EF ratios.
PM25-FIL	1.92 x % Sulfur content of oil	LB	E3GAL	2.861	AP-42 Table 1.3-7. EF calculated from formula of 5.17(A); where A=1.12(S)+0.37; Assumed S=1% for purpose of calculating EF ratios.
PM-CON	1.5	LB	E3GAL	1.5	AP-42, Table 1.3-2
PM10-PRI		LB	E3GAL	9.20	
PM25-PRI		LB	E3GAL	4.36	
Commercial/Institutional Heating: Natural Gas (SCC 2103006000)					
PM10-FIL	1.9	LB	E6FT3	1.9	AP-42 Table 1.4-2
PM25-FIL	1.9	LB	E6FT3	1.9	AP-42 Table 1.4-2
PM-CON	5.7	LB	E6FT3	5.7	AP-42 Table 1.4-2
PM10-PRI		LB	E6FT3	7.60	
PM25-PRI		LB	E6FT3	7.60	
Commercial/Institutional Heating: Liquified Petroleum Gas (SCC 2103007000)					
PM10-FIL	0.4	LB	E3GAL	0.4	AP-42 Table 1.5-1 (Propane for Commercial Boilers)
PM25-FIL	0.4	LB	E3GAL	0.4	AP-42 Table 1.5-1 (Propane for Commercial Boilers)
PM-CON	0.506	LB	E3GAL	0.506	Used natural gas PM-CON emission factor of 5.7 lb/Million Cubic Feet (for all PM controls and uncontrolled). Used factor of 0.0887 to convert emission factor from lb/Million Cubic Feet of natural gas to lb/1,000 gallons of propane. Reference: AP-42, Table 1.4-2. Conversion factor assumes 1020 Btu/scf for natural gas (AP-42, Table 1.4-2) and 90,500 Btu/gallon for propane (AP-42, Appendix A, page A-5).
PM10-PRI		LB	E3GAL	0.91	
PM25-PRI		LB	E3GAL	0.91	
Commercial/Institutional Heating: Kerosene (SCC 2103011000)					
PM10-FIL	1.08	LB	E3GAL	1.08	AP-42 Table 1.3-7 Used EF for Distillate Oil (per EIIP)
PM25-FIL	0.83	LB	E3GAL	0.83	AP-42 Table 1.3-7 Used EF for Distillate Oil (per EIIP)
PM-CON	1.3	LB	E3GAL	1.3	AP-42 Table 1.3-2 Used EF for Distillate Oil (per EIIP)
PM10-PRI		LB	E3GAL	2.38	
PM25-PRI		LB	E3GAL	2.13	
Residential Heating: Anthracite Coal (SCC 2104001000)					
PM10-FIL	10	LB	TON	10	EPA, 2002.
PM25-FIL	0.6 x % Ash content of coal	LB	TON	8.03	EF calculated from formula of 0.6 * % Ash Content (13.38%). Reference for EF and ash content is EPA, 2002.
PM-CON	0.08 x % Ash content of coal	LB	TON	1.07	EF calculated from formula of 0.08 * % Ash Content (13.38%). Reference for EF and ash content is EPA, 2002.
PM10-PRI		LB	TON	11.07	
PM25-PRI		LB	TON	9.10	

Table III-2 (continued)

Pollutant[1]	Uncontrolled Emission Factor (EF)	EF Numerator	EF Denominator	Calculated Uncontrolled EF	Reference
Residential Heating: Bituminous and Lignite Coal (SCC 2104002000)					
PM10-FIL	6.2	LB	TON	6.2	AP-42 Table 1.1-11
PM25-FIL	3.8	LB	TON	3.8	AP-42 Table 1.1-11
PM-CON	1.04	LB	TON	1.04	AP-42 Table 1.1-5 (0.04 lb/MMBtu * 26 MMBtu/ton=1.04)
PM10-PRI		LB	TON	7.24	
PM25-PRI		LB	TON	4.84	
Residential Heating: Distillate Oil (SCC 2104004000)					
PM10-FIL	1.08	LB	E3GAL	1.08	AP-42 Table 1.3-7 (Commercial/Institutional EF)
PM25-FIL	0.83	LB	E3GAL	0.83	AP-42 Table 1.3-7 (Commercial/Institutional EF)
PM-CON	1.3	LB	E3GAL	1.3	AP-42 Table 1.3-2
PM10-PRI		LB	E3GAL	2.38	
PM25-PRI		LB	E3GAL	2.13	
Residential Heating: Natural Gas - All types (SCC 2104006000)					
PM10-FIL	1.9	LB	E6FT3	1.9	AP-42 Table 1.4.2
PM25-FIL	1.9	LB	E6FT3	1.9	AP-42 Table 1.4.2
PM-CON	5.7	LB	E6FT3	5.7	AP-42 Table 1.4.2
PM10-PRI		LB	E6FT3	7.60	
PM25-PRI		LB	E6FT3	7.60	
Residential Heating: Liquified Petroleum Gas (SCC 2104007000)					
PM10-FIL	0.4	LB	E3GAL	0.4	AP-42 Table 1.5-1 (Same factor used for Propane for Commercial Boilers; based on EIIP)
PM25-FIL	0.4	LB	E3GAL	0.4	AP-42 Table 1.5-1 (Same factor used for Propane for Commercial Boilers; based on EIIP)
PM-CON	0.506	LB	E3GAL	0.506	Used natural gas PM-CON emission factor of 5.7 lb/Million Cubic Feet (for all PM controls and uncontrolled). Used factor of 0.0887 to convert emission factor from lb/Million Cubic Feet of natural gas to lb/1,000 gallons of propane. Reference: AP-42, Table 1.4-2. Conversion factor assumes 1020 Btu/scf for natural gas (AP-42, Table 1.4-2) and 90,500 Btu/gallon for propane (AP-42, Appendix A, page A-5).
PM10-PRI		LB	E3GAL	0.91	
PM25-PRI		LB	E3GAL	0.91	
Residential Heating: Kerosene (SCC 2104011000)					
PM10-FIL	1.08	LB	E3GAL	1.08	AP-42 Table 1.3-7 Used EF for Distillate Oil (per EIIP)
PM25-FIL	0.83	LB	E3GAL	0.83	AP-42 Table 1.3-7 Used EF for Distillate Oil (per EIIP)
PM-CON	1.3	LB	E3GAL	1.3	AP-42 Table 1.3-2 Used EF for Distillate Oil (per EIIP)
PM10-PRI		LB	E3GAL	2.38	
PM25-PRI		LB	E3GAL	2.13	

[1] PM10-PRI EF = sum of PM10-FIL and PM-CON emission factors; PM25-PRI EF = sum of PM25-FIL and PM-CON emission factors.

Revisions to the NEI for residential LPG and kerosene were completed after the preliminary 2002 NEI was released in February 2004. Connecticut, the District of Columbia, Maine, and Rhode Island approved replacement of the preliminary 2002 NEI estimates with the revised estimates for LPG. Connecticut was the only State that elected to use the NEI for the residential kerosene category, and Connecticut approved replacing the preliminary 2002 NEI for this category with the revised inventory prepared by EPA.

Other Sources of PM Emissions

For States that provided only PM10-FIL and PM25-FIL emissions, PM10-PRI emissions were set equal to PM10-FIL emissions and PM25-PRI emissions were set equal to PM25-FIL emissions. The PM10-PRI and PM25-PRI emissions that were added to the inventory were assigned a data source code of S-02-X-PR where S-02-X represents the code assigned to the PM10-FIL and PM25-FIL emissions provided by the State agency and the "-PR" indicates that the ratio was applied to estimate the primary emissions (in this case, the ratio of primary to filterable emissions is "1").

PM25-PRI emissions missing from State inventories were estimated by applying a ratio of PM25-PRI-to-PM10-PRI emissions to the PM10-PRI emissions provided by the State agency. Table III-3 identifies the agencies with SCCs for which ratios were applied to estimate PM25-PRI emissions. This table also shows the ratios and the reference for the ratios.

Table III-3. SCCs for which PM25-PRI Emissions were Estimated by Applying a Ratio to the PM10-PRI Emissions in the State inventory

SCC	SCC Description	Agency	Ratio of PM25-PRI to PM10-PRI	Reference
2309100010	Industrial Processes: Fabricated Metals: SIC 34: Coating, Engraving, and Allied Services: Electroplating	NY	0.947	AP-42 emission factors for hard chrome plating tank controlled with mist eliminator. AP-42 (Table 12.20-3) shows 94.7% of total PM as less than 2.35 micrometers. Applied factor to State-supplied PM10-PRI emissions to estimate PM25-PRI emissions.
2461023000	Solvent Utilization: Miscellaneous Non-industrial: Commercial: Asphalt Roofing: Total: All Solvent Types	MA	1	No data available; assumed PM25-PRI equals PM10-PRI.
2601000000	Waste Disposal, Treatment, and Recovery: On-site Incineration: All Categories: Total	MD, NH	1	No data available; assumed PM25-PRI equals PM10-PRI.
2610000100	Waste Disposal, Treatment, and Recovery: On-site Incineration: All Categories: Yard Waste - Leaf Species Unspecified	NH	1	No data available; assumed PM25-PRI equals PM10-PRI.
2810001000	Miscellaneous Area Sources: Other Combustion: Forest Wildfires: Total	MD	1	No data available; assumed PM25-PRI equals PM10-PRI.
2810015000	Miscellaneous Area Sources: Other Combustion: Prescribed Burning for Forest Management: Total	MD	1	No data available; assumed PM25-PRI equals PM10-PRI.
2810020000	Miscellaneous Area Sources: Other Combustion: Prescribed Burning of Rangeland: Total	MD	0.86	Based on ratio of PM25-PRI to PM10-PRI for same SCC used by States in 2002 NEI.
2810030000	Miscellaneous Area Sources: Other Combustion: Structure Fires: Total	MD, NH	0.91	NEI Method.
2810050000	Miscellaneous Area Sources: Other Combustion: Motor Vehicle Fires: Total	MD, NH	0.91	NEI Method.

d. 2002 NEI

Merging of NEI Data into State Inventories

The area source inventory provided by each State agency was compared to the 2002 NEI to identify categories in the NEI that were not in each State inventory. The list of categories identified was provided to each State agency and each agency then selected the NEI categories to be added to its inventory. Identification of categories included in the 2002 NEI but not in a State inventory involved a two-step process. First, Pechan identified the categories in the NEI that did not have an electronic match on the data key of the EM table between the State inventory and the NEI. Then, Pechan manually compared the NEI categories without an electronic match to the State inventory to identify and eliminate NEI categories that were in the State inventory but had a different SCC. For example, a State inventory may use a general SCC for a category while the NEI may use different SCCs to breakout emissions at a finer detail. Examples of categories where this typically occurred include the residential wood combustion, open burning of land clearing debris, solvent utilization, and petroleum marketing and transportation categories. In addition, if a State agency requested that a MANE-VU-sponsored inventory be added to its inventory, the NEI categories that overlapped with the MANE-VU -sponsored categories were removed from the list of NEI categories considered for incorporation into a State inventory.

The source categories in the 2002 NEI that were added to a State inventory can be identified where the data source code starts with “E”. These categories can be identified using the data source code field in the NIF 3.0 files or in the summary of area source emissions that contains the data source code.

Revisions to the Preliminary 2002 NEI

During preparation of the MANE-VU inventory, EPA completed revisions to the emissions for six categories in the preliminary 2002 NEI released in February 2004. As agreed to with each State agency, the revised emissions were used in the MANE-VU inventory in lieu of the preliminary 2002 NEI emissions if the agency requested that the category be included.

- Non-Residential Construction (SCC 2311020000): 2002 emissions data replaced data in preliminary 2002 NEI that were carried forward from 1999 NEI.

- Highway Construction (SCC 2311030000): 2002 emissions data replaced data in preliminary 2002 NEI that were carried forward from 1999 NEI.

- Open Burning of Land Clearing Debris (SCC 2610000500): 2002 emissions data replaced data in preliminary 2002 NEI that were carried forward from 1999 NEI. The activity for this category was based on activity prepared for the non-residential and highway construction categories. For 2002, emissions were set to zero for counties with a population that was 80% urban or more based on 2000 Census data. This was not done for the 1999 NEI. For the NEI method, it was assumed that highly urban counties do not allow this activity to take place. Note that 2002 emissions data were already included in the preliminary 2002 NEI for the open burning of residential municipal solid waste, open burning of yard waste, and the residential construction categories.

- Residential LPG Combustion (SCC 2104007000): 2000 emissions data replaced data in the preliminary 2002 NEI that were carried forward from 1999 NEI.

- Residential Kerosene Combustion (SCC 2104011000): 2000 emissions data replaced data in the preliminary 2002 NEI that were carried forward from 1999 NEI.

- Residential Wood Combustion (SCCs starting with 2104008xxx; 4 SCCs for fireplaces and 3 SCCs for woodstoves): The preliminary 2002 NEI emissions were revised to:

- Correct the CO, PM10-PRI, and PM25-PRI emission factors for fireplaces without inserts (this change doubled the emission factors associated with correcting an error in converting the values from g/kg to lb/ton);

- Correct the climate zone map for allocating national activity to States;

- Replace 1997 total residential wood consumption with 2001 estimates (this change reduced wood consumption for fireplaces with inserts and woodstoves);

- Update urban/rural population data to reflect 2002 estimates based on year 2002 total county population and year 2000 county ratios of urban/rural population to total population; and

- Change the data source code from E-02-X (this was incorrect) to E-01-X to reflect 2001 activity data adjusted to 2002.

e. QA Review of Final Inventory

Final QA checks were run on the revised data set to ensure that all corrections provided by the State agencies were incorporated into the State inventories and that there were no remaining QA issues that could be addressed during the duration of the project. After exporting the inventory in Oracle to an Access database in NIF 3.0, the EPA's QA program was run on the Access database and the QA output was reviewed to verify that all QA issues that could be addressed were resolved (EPA, 2004a).

The output file from the EPA's QA program run on the area source inventory is provided in an Access 2000 database along with the Access database containing the area source inventory in NIF 3.0.

Additional Work on Area Source Methods

- Fugitive Dust Emissions from Paved and Unpaved Roads

Review of Methods

This work involved compiling and summarizing information on emission estimation methods and data sources from the MANE-VU State agencies, RPOs, and EPA for the following fugitive dust area source categories: windblown dust, paved and unpaved roads, agricultural tiling and harvesting, and construction activities. A short survey form was prepared and sent to the MANE-VU State agencies to collect information on whether an agency had activity for each category during 2002. For each agency for which activity occurred in its jurisdiction during 2002, information was requested on the methods and data sources it used to prepare its 2002 inventory for each category. This information was used to prioritize the categories (e.g., work on agricultural field burning was eliminated from further consideration if MANE-VU State agencies did not have activity for this category). The methods and data applied by RPOs other than MANE-VU were obtained from RPO websites and discussions with the RPOs.

The results of this review were documented in a technical memorandum (MANE-VU, 2004b). Based on the results of the review, MANE-VU decided to proceed with developing a paved and unpaved road fugitive dust inventory that incorporated improvements to activity data used in the NEI methodology.

Methods for Improving Paved and Unpaved Road Fugitive Dust Inventory

Fugitive dust emissions from paved and unpaved roads are classified under SCCs 2294000000 and 2296000000, respectively. Fugitive dust emissions from paved and unpaved road traffic were estimated for PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL. Since these categories are not sources of PM-CON, PM10-PRI emissions are equal to PM10-FIL emissions and PM25-PRI emissions are equal to PM25-FIL. The following provides a summary of the methods.

Paved Roads

Several changes were made in the paved road fugitive dust emission calculations to improve these estimates over those prepared for EPA’s 2002 NEI. First, the monthly precipitation data representing the number of days in a month with at least 0.01 inches of precipitation were developed at the county level. In comparison, a single monthly precipitation value was used to model an entire State in the 2002 NEI. Thus, the resulting MANE-VU county-specific paved road fugitive dust emission estimates should be more representative of each county than the NEI data since precipitation events can vary significantly from one part of the State to another.

The second improvement made to the paved road fugitive dust emission calculations was the use of county and road-type-specific average vehicle weights. This is an improvement over the NEI where a single average vehicle weight is applied nationwide. Thus, in the MANE-VU inventory, county/road type combinations with significant heavy truck traffic have a higher average vehicle weight and a corresponding emission factor compared to county/road type combinations with primarily lighter vehicle traffic.

The final improvement made to the MANE-VU paved road emission calculations was the use of the winter silt loading adjustments. These adjustments account for the application of sand and salt on the roads during months with frozen precipitation. The 2002 NEI does not include any wintertime silt loading adjustments. The effect of the wintertime silt loading adjustments is an increase in the paved road emission factors during the months in which it is applied. The months during which this adjustment was applied varied by State in the MANE-VU inventory.

Unpaved Roads

The county-specific precipitation data used in the paved road fugitive dust calculations were also used to improve the unpaved road fugitive dust calculations. As with the paved roads, this represents an improvement over the State-specific precipitation data used in the 2002 NEI unpaved road emission inventory. The other improvement made to the unpaved roads was the use of State-supplied unpaved road mileage data by county for Maine.

- Wildfires and Prescribed Burning

Review of Methods

This work involved compiling and summarizing information on emission estimation methods and data sources from the MANE-VU State agencies, RPOs, and EPA for the following area source categories: wildfires, prescribed burning, slash burning, and agricultural field burning. The approach previously described for the fugitive dust categories was used to collect and compile data from the MANE-VU State agencies, RPOs other than MANE-VU, and EPA for the fire categories. All of the information collected from these various information sources was summarized in a technical memorandum (MANE-VU, 2004c).

Results of Methods Review

MANE-VU recognized the need to improve the methods for estimating emissions for the fire categories. The most important revision would be to inventory fire events as point sources rather than as area sources at the county-level. However, due to resource constraints, it was decided not to pursue improvements to the methods for estimating emissions from the fire categories. It should be noted that during this project, some of the MANE-VU States provided revisions to their wildfire and prescribed burning inventories to add PM25-PRI emissions and to improve the spatial allocation of activity data at the county level. These improvements were incorporated into the MANE-VU area source inventory.

3. Version 3 Revisions

The following explains revisions to Version 3 that applied to several or all of the MANE-VU States.

Gap Filling

In Version 2 of MANE-VU's inventory, emissions for PFCs, industrial adhesives, and residential outdoor wood burning existed for some States but were missing for other States. Since these are categories for which SIP rules may be developed, it was determined that emissions for these categories should be added to Version 3. The following provides a summary of the Version 3 revisions to address missing data concerns for these categories:

- PFCs: MANE-VU estimated default 2002 emissions for these States using a per capita emission factor and county population data for each State. The derivation of the emission factor, population data, and calculation of annual and daily VOC emissions for PFCs is provided in an Excel file named "PFC_Adhesive Calcs for 2002_022106.xls" along with this TSD.

Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont elected to use MANE-VU's default inventory which was added to Version 3. Massachusetts elected to use the per capita emission factor but provided revisions to the population data, used 2002 owner occupied units to allocate the emissions to counties, and then allocated emissions between the commercial (16%) and residential (84%) sectors. Massachusetts' calculations are provided in the spreadsheet named "Version 3 Revisions" in the Excel file named MA_AR_QA_Report_030806.xls" provided with this TSD.

- Industrial Adhesives: Emissions for industrial adhesives were missing in Version 2 for Connecticut, the District of Columbia, Delaware, Maryland, Massachusetts, and Rhode Island. MANE-VU estimated default 2002 emissions for these States using a per capita emission factor and county population data for each State. The derivation of the emission factor, population data, and calculation of annual and daily VOC emissions for industrial adhesives is provided in an Excel file named "PFC_Adhesive Calcs for 2002_022106.xls" along with this TWD.

  Massachusetts elected to use MANE-VU's gap-filling inventory which was added to Version 3. The rest of the States elected to use EPA's 2002 inventory which is based on a top-down, mass balance methodology where national industrial adhesive solvent estimates were allocated to counties using industrial employment. The EPA estimates were adjusted to remove uncontrolled VOC emissions included in the final 2002 point source NEI. The point-source adjustments were conducted at the county level. Note that the point-source-adjusted emissions for Rhode Island are zero for all three counties.

  Note New Jersey is the only State that prepared its own 2002 inventory for this category that is included in Version 3. The industrial adhesive inventory data for the rest of the MANE-VU States originates from the 1999 NEI. These States were contacted to determine if they wanted the 1999 data replaced with the default estimates or with the EPA's 2002 inventory for industrial adhesives. Maine commented that the 1999 estimates are more realistic of the solvent emissions for their State than the 2002 NEI or MANE-VU default estimates. The other States did not indicate that they wanted their data replaced. Therefore, the 1999 NEI data for Maine, New Hampshire, New York, Pennsylvania, and Vermont was not changed in Version 3 of MANE-VU's inventory.

- Residential Wood Burning: Residential outdoor wood burning emissions were missing in Version 2 of the MANE-VU inventory for the District of Columbia, Pennsylvania, Rhode Island, and Vermont. In Versions 1 and 2, New Jersey's and New York's emissions for outdoor wood burning were included with their inventory for indoor wood burning. The District of Columbia, Rhode Island, and Vermont elected to use MANE-VU's outdoor wood burning inventory which was added to Version 3. In addition, per direction provided by New Jersey, its wood burning inventory was replaced with the MANE-VU-sponsored indoor wood burning inventory in Version 3, and the MANE-VU outdoor wood burning inventory was added to Version 3.

New York's inventory in Version 2 included emissions for both residential indoor and outdoor wood burning. For Version 3, New York provided revisions that lowered its overall emissions relative to Version 2 and broke out its inventory to show emissions for fireplaces, woodstoves, and outdoor equipment separately. New York also added NH_3 emissions to its inventory for Version 3.

Adjustments to $PM_{2.5}$ Emissions for Fugitive Dust Categories

Information developed by the Western Governors' Association, Western Regional Air Partnership (WRAP) Dust Emissions Joint Forum and EPA indicates that, for paved and unpaved roads and the construction nonpoint source categories, the $PM_{2.5}$-to-PM_{10} ratio is lower than the ratio used in the EPA method to estimate PM25-PRI/-FIL emissions from PM10-PRI/-FIL emissions (WRAP, 2005). Therefore, for the final 2002 NEI, EPA applied an adjustment factor to the PM25-PRI/-FIL emissions to correct for overestimates of PM25-PRI/-FIL emissions for these categories. Because the $PM_{2.5}$-to-PM_{10} ratio used for the MANE-VU States is based on the EPA method, this information was communicated to the MANE-VU States and all of the States agreed that these adjustments should be made to the MANE-VU inventory. Table III-4 identifies the categories to which this adjustment was applied, the old and new $PM_{2.5}$-to-PM_{10} ratios, and the adjustment factors applied to the PM25-PRI/-FIL emissions in Version 3 of MANE-VU's inventory. Note that these adjustments to $PM_{2.5}$ emissions were applied prior to applying the transport adjustment factors for PM_{10} and $PM_{2.5}$ emissions. The modelers applied the transport adjustment factors to the mass emissions in Version 3. Documentation of the file containing the transport adjustment factors is provided under "Speciation Profiles" section of Table VII-1 in Chapter VII.

For the construction categories, the EPA assumed an original $PM_{2.5}$-to-PM_{10} ratio of 0.15 and an adjustment factor of 0.67. However, the original $PM_{2.5}$-to-PM_{10} ratio used for both the NEI method and MANE-VU's inventory for construction is 0.2. Based on discussions with EPA, the goal is to revise the original $PM_{2.5}$ emissions such that the $PM_{2.5}$-to-PM_{10} ratio is 0.1. Therefore, for Version 3 of MANE-VU's 2002 area source inventory, an adjustment factor of 0.5 (ratio of 0.1-to-0.2) was applied to adjust the $PM_{2.5}$ emissions.

Note that based on Pechan's discussions with EPA during the week of March 6, 2006 concerning the application of the paved road $PM_{2.5}$ adjustment factor, it was determined that adjusting the emissions by applying the factor (shown in Table III-4) to the $PM_{2.5}$ emissions is a simplistic approach. The EPA noted that it is evaluating this issue and will be issuing guidance in the near future for revising the equation for estimating $PM_{2.5}$ emissions which, when applied, will likely yield different results. Because EPA was unable to provide guidance on how to address this issue before Version 3 needed to be completed during the week of March 6, the adjustment factor shown in Table III-4 was applied to the $PM_{2.5}$ emissions for paved roads because this adjustment will provide a better estimate of $PM_{2.5}$ emissions than the unadjusted emissions.

Table III-4. Revisions to PM25-PRI and PM25-FIL Emissions for Paved and Unpaved Roads and Construction

SCC	SCC Description	Original $PM_{2.5}$-to-PM_{10} Ratio	Revised $PM_{2.5}$-to-PM_{10} Ratio	Adjustment Factor[1,2]
2294000000	Mobile Sources : Paved Roads : All Paved Roads : Total: Fugitives	0.25	0.15	0.6
2296000000	Mobile Sources : Unpaved Roads : All Unpaved Roads : Total: Fugitives	0.15	0.1	0.67
2296005000	Mobile Sources : Unpaved Roads : Public Unpaved Roads : Total: Fugitives	0.15	0.1	0.67
2296010000	Mobile Sources : Unpaved Roads : Industrial Unpaved Roads : Total: Fugitives	0.15	0.1	0.67
2311000000	Industrial Processes : Construction: SIC 15 - 17 : All Processes : Total	0.2	0.1	0.50
2311010000	Industrial Processes : Construction: SIC 15 - 17 : Residential : Total	0.2	0.1	0.50
2311010040	Industrial Processes : Construction: SIC 15 - 17 : Residential : Ground Excavations	0.2	0.1	0.50
2311020000	Industrial Processes : Construction: SIC 15 - 17 : Industrial/Commercial/Institutional : Total	0.2	0.1	0.50
2311020040	Industrial Processes : Construction: SIC 15 - 17 : Industrial/Commercial/Institutional : Ground Excavations	0.2	0.1	0.50
2311030000	Industrial Processes : Construction: SIC 15 - 17 : Road Construction : Total	0.2	0.1	0.50

[1] For these categories, filterable and primary emissions are equal because they are not sources of condensible emissions. The adjustment factor was applied to both the PM25-PRI and PM25-FIL emissions and emission factors in the MANE-VU inventory.

[2] See text for discussion of issue concerning the adjustment factor for paved road $PM_{2.5}$ emissions. Also, for construction, see text for explanation of $PM_{2.5}$ adjustment factor shown in this table.

Removal of Invalid CE Records

For the following SCCs, Version 2 contained invalid CE records for Connecticut, the District of Columbia, Maine, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont that were removed in Version 3:

SCC	SCC Description
2311020000	Construction: SIC 15 - 17 : Industrial/Commercial/Institutional : Total
2311030000	Construction: SIC 15 - 17 : Road Construction : Total
2610000100	Open Burning : All Categories : Yard Waste - Leaf Species Unspecified
2610000400	Open Burning : All Categories : Yard Waste - Brush Species Unspecified
2610030000	Open Burning : Residential : Household Waste

The CE records all originate from the preliminary 2002 NEI that have been removed from the final 2002 nonpoint NEI. They are invalid because they have a control efficiency value of 100% and corresponding records in the EM table with rule effectiveness and rule penetration values of 100% (implying that the emissions are zero), but with emissions greater than zero. The Excel spreadsheet file named “CE_records_removed from V3.xls” provides the CE records by State and county FIPS, SCC, and pollutant code that were removed in Version 3.

4. Version 3 Emissions Summary

Table III-5 presents a State-level summary of the annual area source emissions in Version 3 of the 2002 MANE-VU inventory. Note that PM10-PRI and PM25-PRI emissions are included in the inventory for all SCCs for which State agencies reported any form of PM, PM_{10}, and/or $PM_{2.5}$ emissions. If an agency did not report PM10-PRI and/or PM25-PRI but reported PM-PRI, PM-FIL, PM-CON, PM10-FIL, and/or PM25-FIL, the PM augmentation procedures discussed in the TSD were applied to the form of PM emissions supplied by the agency to calculate emissions for the other forms of PM emissions. If an agency reported PM10-PRI and/or PM25-PRI emissions but not PM10-FIL, PM25-FIL, or PM-CON emissions, the agency's inventory was not augmented to calculate filterable or condensible emissions. Note that PM-CON is associated with only fuel combustion sources.

For NH_3, the area source inventory includes emissions for natural sources for the following States: SCCs 28060xxxxx for domestic cats and dogs in Delaware, Massachusetts, and New Jersey; 28070xxxxx for wild animals in Delaware, Massachusetts, New Jersey, and New York; and SCC 2810010000 for human perspiration in Delaware, Massachusetts, and New Jersey. The area source inventory also includes NH_3 biogenic emissions (SCC 2701420000) for Massachusetts.

Table III-5. Version 3 2002 MANE-VU Area Source Emissions by State (Tons/Year)

State	CO	NH_3	NO_x	PM10-FIL	PM10-PRI	PM25-FIL	PM25-PRI	PM-CON	SO_2	VOC
Connecticut	70,198	5,318	12,689	37,790	48,281	4,038	14,247	846	12,418	87,302
Delaware	14,052	13,279	2,608	12,910	13,039	3,075	3,204	128	1,588	15,519
District of Columbia	2,300	14	1,644	5,745	6,293	507	1,029	147	1,337	6,432
Maine	109,223	8,747	7,360	155,237	168,953	19,090	32,774	686	13,149	100,621
Maryland	141,178	25,834	15,678	31,116	95,060	3,375	27,318	611	12,393	120,254
Massachusetts	136,552	18,809	31,358	150,046	192,839	23,354	42,067	1,156	54,923	162,016
New Hampshire	79,647	2,158	10,960	32,138	43,328	6,688	17,532	449	7,072	65,370
New Jersey	97,657	17,572	26,692	37,282	61,601	2,811	19,350	476	10,744	167,882
New York	356,254	67,422	98,803	288,991	369,595	30,894	87,154	102	130,409	507,292
Pennsylvania	266,935	79,911	47,591	363,173	391,897	51,792	74,925	266	63,679	240,785
Rhode Island	8,007	883	3,886	7,090	8,295	887	2,064	336	4,557	31,402
Vermont	43,849	9,848	3,208	51,392	56,131	6,729	11,065	180	4,087	23,265
MANE-VU	**1,325,853**	**249,795**	**262,477**	**1,172,909**	**1,455,311**	**153,243**	**332,729**	**5,383**	**316,357**	**1,528,141**

B. State-Specific Methods

For each of the MANE-VU States, this section identifies the temporal basis of the emissions included in Version 3 and discusses revisions incorporated into Version 3. In addition, this section also discusses the origin of each State agency's emissions included in Version 3. For each agency, a table is provided in Appendix B that lists the data source codes by SCC, emission type period, and pollutant. In addition, an electronic folder is provided for each State agency containing the QA Summary Reports prepared for Versions 1, 2, and/or 3 and other files documenting revisions included in Versions 2 and 3. Except for Rhode Island, a QA Summary Report was prepared for Version 1. Subsequently, a QA Summary Report was prepared for States that provided Version 2 or 3 revisions. Rhode Island elected to use EPA's draft 2002 NEI for Versions 1 and 2 but provided revisions for Version 3; therefore, a QA Summary Report is available for Version 3 only for Rhode Island.

1. Connecticut

Table III-6 shows the emission type periods for which Connecticut provided emissions.

Table III-6. Connecticut 2002 Area, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
DAILY	20011201	20020228	27
DAILY	20020601	20020831	27
DAILY	20020601	20020831	29

Table B-1 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Connecticut provided 2002 emissions for many of the area source categories in Version 3. Connecticut elected to use the EPA's 2002 inventory for industrial adhesives. Connecticut elected to use MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for indoor and outdoor residential wood combustion;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads;
- Annual and daily NH_3 emissions for industrial refrigeration processes;
- Annual and daily VOC emissions for PFCs; and
- Annual and daily VOC and NH_3 emissions for composting.

Emissions for the remaining area source categories were taken from the draft 2002 NEI. For Connecticut, these emissions are either based on 2002 data prepared by EPA or carried forward from final Version 3 of the 1999 NEI. Data carried forward from the 1999 NEI originate from either State data included in the 1999 NEI or EPA data developed for the 1999 NEI.

2. Delaware

Table III-7 shows the emission type periods for which Delaware provided emissions.

Table III-7. Delaware 2002 Area, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type	Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20020831	30	DAILY	20011201	20020228	27
ANNUAL	20020101	20021231	30	DAILY	20020101	20020831	27
ANNUAL	20020512	20020512	30	DAILY	20020512	20020512	27
ANNUAL	20020629	20020629	30	DAILY	20020601	20020831	27
ANNUAL	20021029	20021029	30	DAILY	20020629	20020629	27
ANNUAL	20021104	20021104	30	DAILY	20021029	20021029	27
ANNUAL	20021205	20021205	30	DAILY	20021104	20021104	27
				DAILY	20021205	20021205	27

Table B-2 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Delaware provided 2002 emissions for the majority of the area source categories in Version 3, and used 2002 data that EPA prepared for the draft 2002 NEI or MANE-VU-sponsored inventories for the remaining categories. Delaware elected to use the EPA's 2002 inventory for industrial adhesives, and prepared its own inventory for PFCs. Delaware elected to use data from MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for indoor and outdoor wood burning;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved roads (note: there are no unpaved roads in Delaware);
- Annual and daily NH_3 emissions for POTWs; and
- Annual VOC, NO_x, CO, NH_3, PM10-PRI, PM10-FIL, PM25-PRI, PM25-FIL, and SO_2 emissions for open burning categories.

3. District of Columbia

Table III-8 shows the emission type periods for which the District of Columbia provided emissions.

**Table III-8. District of Columbia 2002 Area, Version 3:
Unique List of Start Date, End Date, and Emission Types**

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
DAILY	20011201	20020228	27
DAILY	20020601	20020831	27

Table B-3 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. The District of Columbia provided 2002 emissions for the majority of the area source categories in Version 3. The District of Columbia provided annual VOC emissions for PFCs for Version 2 that were kept in Version 3. The District of Columbia elected to use the EPA's 2002 inventory for industrial adhesives and indoor wood burning. The exception is for the following categories for which the District of Columbia elected to use data from MANE-VU-sponsored inventories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for outdoor wood burning;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved roads (note: there are no unpaved roads in the District of Columbia);
- Annual and daily VOC and NH_3 emissions for composting; and
- Annual VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for open burning categories.

4. Maine

Table III-9 shows the emission type periods for which Maine provided emissions.

**Table III-9. Maine 2002 Area, Version 3:
Unique List of Start Date, End Date, and Emission Types**

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
DAILY	20011201	20020228	27
DAILY	20020601	20020831	27
DAILY	20020601	20020831	29
DAILY	20020601	20020929	29

Table B-4 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Maine provided 2002 emissions for many of the area source categories in Version 3. Maine's inventory for industrial adhesives originates from the 1999 NEI. Maine provided annual and daily VOC and annual NH_3 emissions for industrial wastewater treatment that were added to Version 3. Maine elected to use data from MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for indoor and outdoor wood burning;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads;
- Annual and daily VOC emissions for PFCs; and
- Annual and daily VOC and NH_3 emissions for composting.

5. Maryland

Table III-10 shows the emission type periods for which Maryland provided emissions. Table B-5 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC.

Table III-10. Maryland 2002 Area, Version 3:
Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type	Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30	MONTHLY	20020101	20020131	30
SEASONAL	20020401	20020930	30	MONTHLY	20020201	20020228	30
SEASONAL	20020401	20021031	30	MONTHLY	20020301	20020331	30
SEASONAL	20020601	20020831	30	MONTHLY	20020401	20020430	30
DAILY	20011201	20020228	27	MONTHLY	20020501	20020531	30
DAILY	20020101	20021231	29	MONTHLY	20020601	20020630	30
DAILY	20020401	20020930	29	MONTHLY	20020701	20020731	30
DAILY	20020401	20021031	29	MONTHLY	20020801	20020831	30
DAILY	20020601	20020831	27	MONTHLY	20020901	20020930	30
DAILY	20020601	20020831	29	MONTHLY	20021001	20021031	30
				MONTHLY	20021101	20021130	30
				MONTHLY	20021201	20021231	30

Maryland provided 2002 annual, seasonal, and daily emissions for the majority of the area source categories in Version 3 and used 2002 data that EPA prepared for the draft 2002 NEI for industrial adhesives and commercial cooking. Maryland prepared its own inventory for PFCs.

Maryland elected to use data from MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for indoor and outdoor wood burning;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads;
- Annual VOC, NO_x, CO, NH_3, PM10-PRI, PM10-FIL, PM25-PRI, PM25-FIL, and SO_2 emissions for open burning categories; and
- Annual and monthly NH_3 emissions for agricultural crop fertilizers.

For Version 2, Maryland provided revisions to annual, seasonal, and daily VOC emissions for SCC 2505030120 (Storage and Transport : Petroleum and Petroleum Product Transport : Truck : Gasoline). Maryland also removed PM10-FIL and PM25-FIL annual, seasonal, and daily records for open burning of land clearing debris (SCC 2610000500). Maryland had revised the PM10-PRI and PM25-PRI emissions in an earlier version of the MANE-VU inventory but not the PM10-FIL and PM25-FIL. As a result of revising the primary emissions, the filterable emissions were no longer met the consistency check as compared to the primary emissions.

QA of PM emissions in Version 3 identified one record for Maryland in county 510 for SCC 2801000003 (Agriculture - Crops : Tilling) where PM10-PRI annual emissions are 2317.2 tons and PM25-PRI annual emissions are 0 tons. For the other counties in Maryland with this SCC, PM25-PRI emissions are about 20% of the PM10-PRI emissions. This issue was not addressed due to time and resource constraints for completing revisions to Version 3.

6. Massachusetts

Table III-11 shows the emission type periods for which Massachusetts provided emissions.

Table III-11. Massachusetts 2002 Area, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
DAILY	20011201	20020228	27
DAILY	20020601	20020831	27
DAILY	20020601	20020831	29

Table B-6 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. Massachusetts provided 2002 annual and daily emissions for the majority of the area source categories in Version 3 and used 2002 data that EPA prepared for the draft 2002 NEI for residential coal combustion, asphalt roofing, and agricultural livestock (NH_3).

Massachusetts elected to use data from MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for indoor and outdoor wood burning;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads;
- Annual and daily VOC emissions for industrial adhesives and PFCs;
- Annual and daily NH_3 emissions for industrial refrigeration processes;
- Annual and daily VOC and NH_3 emissions for composting; and
- Annual VOC, NO_x, CO, NH_3, PM10-PRI, PM10-FIL, PM25-PRI, PM25-FIL, and SO_2 emissions for open burning categories.

For Version 2, Massachusetts revised annual and summer day VOC emissions for 14 counties for the following categories: aircraft refueling, surface coating, degreasing, miscellaneous non-industrial: consumer and commercial products and pesticides, and gasoline service stations (stage 1: balanced submerged fill). Massachusetts also revised annual and daily emissions for 14 counties for forest wildfires, revised annual emissions for four counties for residential open burning of brush using the correct rule penetration factors for the counties, and revised control efficiency and control device data for selected categories in the CE table.

For Version 3, Massachusetts revised annual and summer day VOC emissions for 14 counties for auto refinishing. In the CE table, Massachusetts changed control device code 102 (low-solvent coatings) to 000 (uncontrolled) and associated control efficiency values were set to null for all counties. Massachusetts also added annual and summer day VOC emissions for 14 counties for gasoline service stations (stage 2: displacement loss/controlled).

For PFCs, Massachusetts elected to use the per capita emission factor but provided revisions to the population data, used 2002 owner occupied units to allocate the emissions to counties, and then allocated emissions between the commercial (16%) and residential (84%) sectors. Massachusetts' calculations are provided in the spreadsheet named "Version 3 Revisions" in the Excel file named MA_AR_QA_Report_030806.xls".

7. New Hampshire

Table III-12 shows the emission type periods for which New Hampshire provided emissions. Table B-7 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. New Hampshire provided 2002 emissions for many of the area source categories in Version 3. New Hampshire's inventory for industrial adhesives originates from the 1999 NEI.

Table III-12. New Hampshire 2002 Area, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
DAILY	20011201	20020228	27
DAILY	20020601	20020831	27
DAILY	20020601	20020831	29
MONTHLY	20020101	20020131	30
MONTHLY	20020201	20020228	30
MONTHLY	20020301	20020331	30
MONTHLY	20020401	20020430	30
MONTHLY	20020501	20020531	30
MONTHLY	20020601	20020630	30
MONTHLY	20020701	20020731	30
MONTHLY	20020801	20020831	30
MONTHLY	20020901	20020930	30
MONTHLY	20021001	20021031	30
MONTHLY	20021101	20021130	30
MONTHLY	20021201	20021231	30

New Hampshire elected to use data from MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for indoor and outdoor wood burning;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads;
- Annual and daily VOC emissions for PFCs;
- Annual and daily NH_3 emissions for industrial refrigeration processes and POTWs;
- Annual and daily VOC and NH_3 emissions for composting;
- Annual VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for open burning categories; and
- Annual and monthly NH_3 emissions for agricultural crop fertilizers and livestock.

Emissions for the remaining area source categories were taken from the draft 2002 NEI; these emissions are either based on 2002 data prepared by EPA or EPA data carried forward from final Version 3 of the 1999 NEI.

New Hampshire provided revisions to Version 2 that were kept in Version 3. For Version 2, New Hampshire revised annual and daily VOC emissions for the gasoline storage and transport sector to reflect revisions it made to the 2002 inventory that EPA prepared for the 2002 NEI. The categories revised include bulk plant breathing losses, gasoline service stations (stages 1 and 2 total and underground tank breathing and emptying losses), and gasoline tank trucks.

8. New Jersey

Table III-13 shows the emission type periods for which New Jersey provided emissions.

**Table III-13. New Jersey 2002 Area, Version 3:
Unique List of Start Date, End Date, and Emission Types**

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
DAILY	20011201	20020228	27
DAILY	20011201	20020228	29
DAILY	20020601	20020831	27
DAILY	20020601	20020831	29

Table B-8 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. New Jersey provided 2002 emissions for the majority of the area source categories. New Jersey provided its own 2002 inventory for industrial adhesives and PFCs. Emissions for the remaining area source categories were taken from the draft 2002 NEI (that are either based on 2002 data prepared by EPA or EPA data carried forward from final Version 3 of the 1999 NEI) or MANE-VU-sponsored inventories. New Jersey elected to use MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for indoor and outdoor residential wood combustion (replacing New Jersey's indoor residential wood combustion inventory provided in Versions 1 and 2);
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved roads;
- Annual and daily NH_3 emissions for industrial refrigeration processes and POTWs; and
- Annual and daily VOC and NH_3 emissions for composting.

For Version 3, New Jersey added annual and summer day VOC emissions for 21 counties for SCC 2501060100 (gasoline service stations : stage 2: total). The emissions are summarized in the spreadsheet named "Version 3 Revisions" in the Excel file named "NJ_AR_QA_Report_030806.xls". New Jersey provided 2002 emissions data for the industrial adhesives and PFC categories in Version 1. For Version 2, New Jersey corrected PM25-PRI emissions that were greater than PM10-PRI emissions for SCC 2601000000 (on-site incineration : all categories : total).

9. New York

Table III-14 shows the emission type periods for which New York provided emissions. Table B-9 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination or because emissions are not reported for all pollutants for the same SCC and emission type period combination.

Table III-14. New York 2002 Area, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
MONTHLY	20020101	20020131	30
MONTHLY	20020201	20020228	30
MONTHLY	20020301	20020331	30
MONTHLY	20020401	20020430	30
MONTHLY	20020501	20020531	30
MONTHLY	20020601	20020630	30
MONTHLY	20020701	20020731	30
MONTHLY	20020801	20020831	30
MONTHLY	20020901	20020930	30
MONTHLY	20021001	20021031	30
MONTHLY	20021101	20021130	30
MONTHLY	20021201	20021231	30

New York provided revisions to annual emissions for all 62 counties for the categories and pollutants shown in Table III-15. This revision completely replaced the 2002 emissions that New York provided in Version 2. Table III-15 also identifies categories and pollutants for which emissions were added to Version 3 (i.e., not in Version 2). The emissions are summarized in the spreadsheet named "Version 3 Revisions" in the Excel file named NY_AR_QA_Report_030806.xls".

New York's inventory in Version 2 included emissions for both residential indoor and outdoor wood burning. For Version 3, New York provided revisions that lowered its overall emissions relative to Version 2 and broke out its inventory to show emissions for fireplaces, woodstoves, and outdoor equipment separately. New York also added NH_3 emissions to its inventory for Version 3. New York's inventory for industrial adhesives originates from the 1999 NEI. New York provided its own 2002 inventory for PFCs. Emissions for the remaining area source categories were taken from the draft 2002 NEI (that are either based on 2002 data prepared by EPA or EPA data carried forward from final Version 3 of the 1999 NEI) or MANE-VU-sponsored inventories.

New York elected to use MANE-VU-sponsored inventories for the following source categories:

- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads;
- Annual and daily NH_3 emissions for agricultural livestock; and
- Annual VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for open burning categories.

A QA issue that may affect the use of the MANE-VU inventory for air quality modeling and revisions to the projection year inventory is the addition of SCCs 2103004001 and 2103004002 by New York that are not in EPA’s master SCC list used by the EPA QA program. These SCCs are defined in Table III-15. In addition, the QA program shows SCCs for PFCs and outdoor wood burning as invalid because EPA has not updated the master list to include these SCCs for the EPA QA program. These SCCs were included in Version 2 and should have been assigned speaciation profiles and included in the projection year inventory prepared from Version 2.

Table III-15. Summary of New York's Revisions to Version 3 of MANE-VU's Area Source Inventory

SCC	SCC Description	Pollutant	Type of Revision to Emissions
Revisions to Waste Disposal, Treatment, and Recovery : Wastewater Treatment			
2630020000	Public Owned : Total Processed	VOC	Revised emissions for all pollutants
Revisions to Stationary Source Fuel Combustion : Residential : Wood			
2104008001	Fireplaces: General	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Added NH3, revised emissions for rest of pollutants
2104008052	Non-catalytic Woodstoves: Low Emitting	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Added emissions for all pollutants
2104008070	Outdoor Wood Burning Equipment	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Added emissions for all pollutants
Revisions to Stationary Source Fuel Combustion : Electric Utility			
2101001000	Anthracite Coal : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	No change to emissions
2101002000	Bituminous/Subbituminous Coal : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2101004000	Distillate Oil : Total: Boilers and IC Engines	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2101005000	Residual Oil : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2101006000	Natural Gas : Total: Boilers and IC Engines	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
Revisions to Stationary Source Fuel Combustion : Industrial			
2102001000	Anthracite Coal : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	No change to emissions
2102002000	Bituminous/Subbituminous Coal : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2102004000	Distillate Oil : Total: Boilers and IC Engines	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2102005000	Residual Oil : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2102006000	Natural Gas : Total: Boilers and IC Engines	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2102007000	Liquified Petroleum Gas (LPG) : Total: All Boiler Types	VOC, NOX, CO, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2102008000	Wood : Total: All Boiler Types	VOC, NOX, CO, SO2, PM10-PRI, PM25-PRI	No change to emissions
2102011000	Kerosene : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Added emissions for all pollutants
Revisions to Stationary Source Fuel Combustion : Commercial/Institutional			
2103001000	Anthracite Coal : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	No change to emissions
2103002000	Bituminous/Subbituminous Coal : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2103005000	Residual Oil : Total: All Boiler Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2103004000	Residual Oil : Total: Boilers and IC Engines	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Removed and replaced with data for SCCs 2103004001 and 2103004002
2103004001	Distillate Oil : Boilers	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Added emissions for all pollutants
2103004002	Distillate Oil : IC Engines	VOC, NOX, CO, SO2, PM10-PRI, PM25-PRI	Added emissions for all pollutants
2103006000	Natural Gas : Total: Boilers and IC Engines	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2103007000	Liquified Petroleum Gas (LPG) : Total: All Combustor Types	VOC, NOX, CO, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2103008000	Wood : Total: All Boiler Types	VOC, NOX, CO, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2103011000	Kerosene : Total: All Combustor Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Added emissions for all pollutants

Table III-15. Summary of New York's Revisions to Version 3 of MANE-VU's Area Source Inventory (Continued)

SCC	SCC Description	Pollutant	Type of Revision to Emissions
Revisions to Stationary Source Fuel Combustion : Residential			
2104001000	Anthracite Coal : Total: All Combustor Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	No change to emissions
2104002000	Bituminous/Subbituminous Coal : Total: All Combustor Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2104004000	Distillate Oil : Total: All Combustor Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2104006010	Natural Gas : Residential Furnaces	VOC, NOX, CO, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2104007000	Liquified Petroleum Gas (LPG) : Total: All Combustor Types	VOC, NOX, CO, SO2, PM10-PRI, PM25-PRI	Revised emissions for all pollutants
2104011000	Kerosene : Total: All Heater Types	VOC, NOX, CO, NH3, SO2, PM10-PRI, PM25-PRI	Added emissions for all pollutants

10. Pennsylvania

Table III-16 shows the emission type periods for which Pennsylvania provided emissions.

Table III-16. Pennsylvania 2002 Area, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type	Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30	MONTHLY	20020101	20020131	30
DAILY	20011201	20020228	27	MONTHLY	20020201	20020228	30
DAILY	20020601	20020831	27	MONTHLY	20020301	20020331	30
				MONTHLY	20020401	20020430	30
				MONTHLY	20020501	20020531	30
				MONTHLY	20020601	20020630	30
				MONTHLY	20020701	20020731	30
				MONTHLY	20020801	20020831	30
				MONTHLY	20020901	20020930	30
				MONTHLY	20021001	20021031	30
				MONTHLY	20021101	20021130	30
				MONTHLY	20021201	20021231	30

Table B-10 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. Note that some SCC and emission type period combinations are listed more than once because the data source codes are different for more than one SCC and emission type period combination. Pennsylvania provided 2002 emissions for the majority of the area source categories. Pennsylvania provided its own 2002 inventory for PFCs and residential indoor wood burning. Pennsylvania's inventory for industrial adhesives originates from the 1999 NEI. Emissions for the remaining area source categories were taken from the draft 2002 NEI (that are either based on 2002 data prepared by EPA or EPA data carried forward from final Version 3 of the 1999 NEI) or MANE-VU-sponsored inventories.

Pennsylvania elected to use MANE-VU-sponsored inventories for the following source categories:

- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads;
- Annual and daily NH_3 emissions for industrial refrigeration processes and agricultural crop fertilizers and livestock;
- Annual and daily VOC and NH_3 emissions for POTWs and composting; and
- Annual VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for open burning categories.

11. Rhode Island

Table III-17 shows the emission type periods for which Rhode Island provided emissions.

**Table III-17. Rhode Island 2002 Area, Version 3:
Unique List of Start Date, End Date, and Emission Types**

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
DAILY	20011201	20020228	27
DAILY	20020601	20020831	27
DAILY	20020601	20020831	29

Table B-11 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. Rhode Island provided 2002 annual VOC emissions for several solvent utilization categories (surface coating, degreasing, graphic arts, rubber/plastics, and industrial adhesive); annual and daily VOC emissions for petroleum and petroleum product storage (gasoline service stations and all transport types); and annual VOC emissions for POTWs. Rhode Island's indoor wood burning inventory originates from the draft 2002 NEI. Emissions for the remaining area source categories were taken from the draft 2002 NEI (that are either based on 2002 data prepared by EPA or EPA data carried forward from final Version 3 of the 1999 NEI) or MANE-VU-sponsored inventories.

Rhode Island elected to use MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for outdoor wood burning;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads; and
- Annual and daily VOC emissions for PFCs.

12. Vermont

Table III-18 shows the emission type periods for which Vermont provided emissions.

Table III-18. Vermont 2002 Area, Version 3: Unique List of Start Date, End Date, and Emission Types

Emission Type Period	Start Date	End Date	Emission Type
ANNUAL	20020101	20021231	30
DAILY	20011201	20020228	27
DAILY	20020601	20020831	27
DAILY	20020601	20020831	29

Table B-12 in Appendix B identifies the data sources by SCC, emission type period, and pollutant in the Version 3 area source inventory. This table also shows the number of counties by SCC. Vermont provided 2002 annual VOC, NO_x, CO, PM10-PRI or PM10-FIL, PM25-PRI or PM25-FIL, and SO_2 emissions for residential fuel combustion (distillate oil, natural gas, LPG, and indoor wood burning); annual VOC emissions for gasoline service stations and breathing losses at bulk terminals; annual VOC, NO_x, CO, PM10-PRI, PM25-PRI, and SO_2 emissions for residential open burning; annual VOC, NO_x, CO, NH_3, PM10-PRI, and PM25-PRI emissions for forest fires, and annual VOC, NO_x, CO, PM10-PRI, and PM25-PRI emissions for structure fires. Vermont's inventory for industrial adhesives originates from the 1999 NEI.

For Version 2, Vermont provided revisions to EPA's draft 2002 inventory for SCC 2501050120 (bulk stations and terminals : breathing loss : gasoline) to incorporate the effects of vapor balance controls not accounted for in the EPA estimates. The revised inventory for this category was added to Version 2 (and kept in Version 3) that did not include this category. Control records were added to the NIF 3.0 CE table for the counties with vapor balance controls. In addition, Vermont provided emissions for three counties (i.e., county FIPS codes 50015, 50017, and 50019) that were not in EPA's inventory. Emissions for the remaining area source categories were taken from the draft 2002 NEI (that are either based on 2002 data prepared by EPA or EPA data carried forward from final Version 3 of the 1999 NEI) or MANE-VU-sponsored inventories. Vermont elected to use MANE-VU-sponsored inventories for the following source categories:

- Annual and daily VOC, NO_x, CO, NH_3, PM10-PRI, PM25-PRI, and SO_2 emissions for outdoor wood burning;
- Annual PM10-PRI, PM10-FIL, PM25-PRI, and PM25-FIL emissions for paved and unpaved roads;
- Annual and daily NH_3 emissions for industrial refrigeration processes and POTWs;
- Annual and daily VOC emissions for PFCs;
- Annual and daily VOC and NH_3 emissions for composting; and
- Annual VOC, NO_x, CO, NH_3, PM10-PRI, PM10-FIL, PM25-PRI, PM25-FIL, and SO_2 emissions for open burning categories.

C. What Issues Need to be Addressed in Future Versions?

This section provides a summary of potential revisions to incorporate into future versions of the MANE-VU area source inventory.

All States – A coordinated effort between the State agencies should be developed to apply consistent methods to avoid having to apply procedures to augment inventory data to correct for the QA issues and fill in missing data as discussed previously in this chapter. For example, this will ensure that consistent methods are applied across State agencies to ensure consistent and accurate reporting of source categories using the same SCCs across States, PM emissions, and minimize other QA issues that were identified during the development of Versions 1, 2, and 3 of the inventory.

For PM emissions, the State agencies should develop and apply a consistent method for including condensible emissions for fuel combustion sources that can be applied when the agencies develop their inventories. This may include compiling the emission factors for all forms of PM into one database, organized by SCC and control type (for filterable emissions), and sharing the database among the MANE-VU State agencies. Use of a consistent set of emission factors will help to avoid the PM consistency issues identified in Versions 1, 2, and 3 of the MANE-VU inventory as well as ensure that condensible emissions are included in the primary emissions reported in the inventory.

State-specific suggestions are as follows:

Delaware: Revise the residential wood combustion emissions inventory with the latest revisions sponsored by MARAMA.

Rhode Island: This State felt that the area sources (from the nonpoint inventory EPA prepared) which they had changed to zeros in Version 3 would revert back to the Version 2 numbers which were from the EPA report. Rhode Island would like to see this change in the next version of the inventory. (Table with changes can be received upon request).

New Jersey:

- Why is the EPA VOC emission factor for fireplaces completely out of proportion with the other emission factors? The ratio of conventional wood stoves/fireplaces = 0% to 10% for other pollutants and is 77% for VOC. It is discussed in the Pechan Technical Memo #5, 9/3/03, page 19, how a study of the accuracy of the emission factors showed the VOC should be more like 10 to 30 lb/ton, instead of 229 lb/ton and the woodstove emission factors (certified) should be higher than Emission Inventory Improvement Program guidance.

- The summer seasonal adjustment factors for indoor wood burning used in the model appear high. This combined with the very high VOC emission factor results in high ozone season wood burning emissions.

- In general, the accuracy of the very large residential wood burning numbers, all pollutants.

- The large fugitive dust inventory numbers don not correlate to dust found in monitors, even with the latest 30% to 40% reduction in paved and unpaved road emissions.

- We need consistent guidance from the EPA for adhesives and sealants, PFC, and commercial cooking.

CHAPTER IV – NONROAD SOURCES

A. General Methods for all States

This section provides an overview of the data sources and QA steps used in preparing the 2002 nonroad sector inventory for the MANE-VU States. The nonroad sector is comprised of nonroad engines included in EPA's NONROAD model, as well as other engines not modeled in NONROAD, including aircraft, commercial marine vessels and locomotives.

1. What Data Sources Were Used?

Data sources used for the various nonroad categories are described below.

a. Aircraft, Commercial Marine, and Locomotive Categories

As a starting point, aircraft, commercial marine vessel and locomotive inventories were prepared using the inventories that State agencies submitted to the EPA in June 2004 as a requirement of the CERR. In addition, some States provided data directly to MANE-VU for use in this inventory that were not submitted for the CERR.

Missing data were supplemented with estimates from EPA's preliminary 2002 NEI. For the aircraft and commercial marine vessel source categories, the 2002 NEI CAP emissions were estimated by carrying over the 2001 estimates. 2001 emissions were estimated using the methodologies described in EPA's *Documentation for Aircraft, Commercial Marine Vessel, Locomotive, and Other Nonroad Components of the National Emissions Inventory* (EPA, 2003b). The 2002 locomotive emissions were calculated using 2002 activity data and the methodologies described in the EPA, 2003b documentation.

Table IV-1 provides a summary of the aircraft, commercial marine, and locomotive emission SCCs reported in the MANE-VU inventory. Table IV-2 provides a summary of the basis for these nonroad subsector emissions by State.

Table IV-1. List of Unique Aircraft, Commercial Marine, and Locomotive SCCs Reported by States in MANE-VU Inventory

SCC	SCC Description 1	SCC Description 2	SCC Description 3	SCC Description 4
2275000000	Mobile Sources	Aircraft	All Aircraft Types and Operations	Total
2275001000	Mobile Sources	Aircraft	Military Aircraft	Total
2275020000	Mobile Sources	Aircraft	Commercial Aircraft	Total: All Types
2275050000	Mobile Sources	Aircraft	General Aviation	Total
2275060000	Mobile Sources	Aircraft	Air Taxi	Total
2275070000	Mobile Sources	Aircraft	Aircraft Auxiliary Power Units	Total
2280000000	Mobile Sources	Marine Vessels, Commercial	All Fuels	Total, All Vessel Types
2280002000	Mobile Sources	Marine Vessels, Commercial	Diesel	Total, All Vessel Types
2280002010	Mobile Sources	Marine Vessels, Commercial	Diesel	Ocean-going Vessels
2280002020	Mobile Sources	Marine Vessels, Commercial	Diesel	Harbor Vessels
2280002100	Mobile Sources	Marine Vessels, Commercial	Diesel	Port emissions
2280002200	Mobile Sources	Marine Vessels, Commercial	Diesel	Underway emissions
2280003100	Mobile Sources	Marine Vessels, Commercial	Residual	Port emissions
2280003200	Mobile Sources	Marine Vessels, Commercial	Residual	Underway emissions
2285000000	Mobile Sources	Railroad Equipment	All Fuels	Total
2285002000	Mobile Sources	Railroad Equipment	Diesel	Total
2285002005	Mobile Sources	Railroad Equipment	Diesel	Total Line Haul Locomotives
2285002006	Mobile Sources	Railroad Equipment	Diesel	Line Haul Locomotives: Class I Operations
2285002007	Mobile Sources	Railroad Equipment	Diesel	Line Haul Locomotives: Class II / III Operations
2285002008	Mobile Sources	Railroad Equipment	Diesel	Line Haul Locomotives: Passenger Trains (Amtrak)
2285002009	Mobile Sources	Railroad Equipment	Diesel	Line Haul Locomotives: Commuter Lines
2285002010	Mobile Sources	Railroad Equipment	Diesel	Yard Locomotives

Table IV-2. Summary of Basis for 2002 MANE-VU Aircraft, Commercial Marine, and Locomotive Inventory

FIPSST	State	Basis for Subsector of Nonroad Inventory		
		Aircraft	Commercial Marine Vessels	Locomotives
09	Connecticut	2002 Preliminary NEI	2002 Preliminary NEI	State supplied in March 2006
10	Delaware	June 2004 CERR Submittal; State supplied revisions in Sep 2004	June 2004 CERR Submittal	June 2004 CERR Submittal
11	District of Columbia	Not supplied by State and not available from NEI	2002 Preliminary NEI	June 2004 CERR Submittal
23	Maine	State supplied in Oct 2004	State supplied in Oct 2004	State supplied in Oct 2004
24	Maryland	June 2004 CERR Submittal; State supplied revisions in Sep 2004	June 2004 CERR Submittal; State supplied revisions in Oct 2004	June 2004 CERR Submittal
25	Massachusetts	June 2004 CERR Submittal	State-supplied for June 2004 CERR Submittal, with revisions as directed by State	June 2004 CERR Submittal
33	New Hampshire	June 2004 CERR Submittal	2002 Preliminary NEI	June 2004 CERR Submittal
34	New Jersey	June 2004 CERR Submittal	June 2004 CERR Submittal	June 2004 CERR Submittal
36	New York	2002 Preliminary NEI	State supplied in Oct 2004	2002 Preliminary NEI
42	Pennsylvania	State supplied to Pechan in June 2004	State supplied to Pechan in June 2004	State supplied to Pechan in June 2004; State supplied revisions in Aug 2005
44	Rhode Island	State-supplied for June 2004 CERR Submittal, with revisions as directed by State	State-supplied for June 2004 CERR Submittal, with revisions as directed by State	State-supplied in Oct 2004
50	Vermont	2002 Preliminary NEI	Not supplied by State and not available from NEI	Not supplied by State and not available from NEI

b. NONROAD Model Categories

NONROAD model categories include equipment such as recreational marine and land-based vehicles, farm and construction machinery, and lawn and garden equipment. Aircraft ground support equipment (GSE) and rail maintenance equipment are also included in NONROAD. These equipment are powered by diesel, gasoline, compressed natural gas (CNG) and LPG engines.

EPA released a final version of NONROAD during December 2005 called NONROAD2005 (EPA, 2005a). To reflect the updates made to EPA's final NONROAD model, all MANE-VU Version 2 NONROAD model estimates were replaced with updated NONROAD2005 emission estimates.

EPA also released an updated version of its NMIM, which incorporates the final NONROAD2005 model. EPA's NMIM2005 is a consolidated modeling system that incorporates the NONROAD and MOBILE models, along with a county database of inputs (EPA, 2005b). The NMIM county database contains monthly input data to reflect county-specific fuel parameters and temperatures. Because incorporating revised monthly inputs for use in NMIM2005 is more efficient than preparing county-specific monthly option files needed to run NONROAD2005 independently, Pechan used NMIM2005 for most MANE-VU States. The two exceptions were for the District of Columbia and Maine due to the differences in oxygenated fuel inputs used for NMIM versus NONROAD.

As a first step, Pechan compiled fuel input data available from NMIM2005 by county and by month for all MANE-VU states for 2002. Pechan developed a spreadsheet that summarized the gasoline RVP, gasoline weight percent oxygen, and gasoline and diesel sulfur content proposed as inputs to the updated runs. Values consistent with State-supplied MOBILE6 inputs used for the development of 2002 MANE-VU highway vehicle inventories were presented for use where they differed from NMIM. Pechan requested that States confirm the use of these data for the NONROAD model runs, or provide alternative inputs.

The final county, monthly NMIM inputs provided or confirmed by the States for RVP, weight percent oxygen, and gasoline sulfur are presented in Appendix C, Table C-1. Pechan used NMIM's 2002 default value for nonroad diesel sulfur content. This value is 2,457 parts per million (ppm) for land-based equipment, and 2,767 ppm for recreational marine, for all MANE-VU counties.

Pechan also requested that States provide any local activity data in the format of updated NONROAD external data files. These include data files which specify activity parameters such as equipment populations, equipment annual hours of use, county allocation factors, and monthly allocation profiles.

Pechan updated the NMIM county database for 2002 to add in new gasoline profiles to reflect the monthly and county fuel input values provided by States. Pechan also updated the NMIM county database to cross reference the State-supplied NONROAD data files that replaced default

NONROAD2005 inputs. Pechan then ran NMIM/NONROAD2005 at the county and monthly level for 2002 and generated the results in NIF 3.0.

c. NONROAD2005 Model Runs

The majority of the model runs were performed using NMIM2005. NMIM and NONROAD have differences in the required format of the oxygenated fuel inputs. For NONROAD, this variable is required to be expressed as a composite weight percent oxygen that accounts for the market share and the percent oxygen of all contributing oxygenates. Since NMIM models HAP emissions, the volume percent and market share of each of four oxygenates must be entered as fuel inputs. These oxygenates include methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), ethanol (ETOH), and tertiary amyl methyl ether (TAME). In cases where only one known oxygenate is present, this is straightforward to reflect in NMIM, as weight percent can be easily converted to volume percent. However, two States (the District of Columbia and Maine) provided a composite weight percent value for more than one oxygenate, but could not provide the corresponding volume percent and market share for each oxygenate to use in NMIM. As such, Pechan used NONROAD2005 for both the District of Columbia and Maine so that their submitted values for weight percent oxygen could be used directly. The 2002 minimum, maximum, and average hourly temperatures included in NMIM2005 were used to calculate average monthly temperature inputs to NONROAD for both States.

Pechan developed monthly NONROAD option files and ran these files through NONROAD2005 to generate monthly emissions that were then summed to develop an annual 2002 inventory. Pechan performed additional calculations using NMIM emission factors and fuel consumption to calculate NH_3, since NONROAD does not calculate NH_3 emissions.

2. What Quality Assurance Steps Were Performed?

The final MANE-VU nonroad inventory was comprised of emission estimates that were either: 1) submitted by States for the June 2004 CERR submittal or as additional revisions after this date; 2) developed using NONROAD model inputs provided or approved by States; or 3) reported by EPA in the preliminary 2002 NEI. As such, the QA steps were tailored to each of these types of submittals. Note that a Quality Assurance Plan was prepared prior to initiating work on Version 1 (MANE-VU, 2003). This plan was applied during development of all three versions of the MANE-VU inventory.

a. Summary of QA checks for State emission submittals

Nonroad emission submittals were accepted as part of the June 2004 CERR submittals to EPA or as direct submittals to MANE-VU. Upon receipt of an emissions submittal, Pechan prepared spreadsheets providing a unique list of errors identified by running the EPA NIF 3.0 QA software tool on the nonroad source inventory (EPA, 2004a). Notes were provided to identify the NIF 3.0 tables in which the errors appeared, as well as clarification as to where an error occurred (e.g., for what SCC and pollutant). For many of the errors, Pechan provided a potential correction, and States indicated whether they agreed with the correction, or provided their own instructions for correcting the error. These spreadsheets served to document each state's direction on how to correct errors and the state's representative authorizing the correction.

The list of general QA checks include the following:

- Duplicate records (i.e., only one record allowed for each unique county/SCC/ pollutant)
- Invalid record type
- Mandatory field is not populated
- Invalid field length
- Invalid data type (e.g., invalid SCCs or pollutants)
- “Out-of-range” emission values
- Referential integrity (i.e., the presence of widow or orphan records in the NIF 3.0 relational tables)

Note that EPA’s NIF 3.0 QA software tool also checks for other specific QA issues by field not listed above. See EPA’s User Guide, Appendix A for a listing of all potential errors that are checked by the program, and EPA’s guidance for how they should be resolved.

Pechan also performed other general QA procedures outside of EPA’s NIF 3.0 QA software tool, including pollutant augmentation, SCC reconciliation, and completeness and reasonableness checks.

Pechan performed pollutant augmentation in cases where the complete set of CAPs and NH_3 were not provided by a State. For example, several States did not provide PM25-PRI, but did provide PM10-PRI, so that PM25-PRI was estimated using EPA-published particle-size multipliers. Where multipliers were not available from EPA documentation, Pechan used available pollutant emission estimates reported by all other MANE-VU States to develop “emission ratios” for a given SCC. These “emission ratios” were then used to multiply available pollutant estimates to estimate values for the missing pollutants. Specific values used for a given State and SCC are cited in the “State-Specific Methods” section below.

In addition, SCC assignments were reviewed and reassigned after clarification from States as to what the specific SCC estimate represented. For example, a State may have reported all aircraft activity under one of the specific aircraft type SCCs (e.g., commercial or general aviation), when it should more accurately be reported under the general SCC 2275000000 (All Aircraft Types and Operations).

Finally, completeness checks were performed on the inventory to determine that emissions for nonroad categories known to operate in a State or county were being reported. Note that emissions may not be reported for all NONROAD SCCs for all counties in the MANE-VU RPO, and will depend on the geographic allocation methods used by the model, or specific allocation data provided by a State.

NONROAD model category estimates originally provided by States for the June 2004 submittal were replaced by emission estimates developed using NMIM/NONROAD 2005. As such, this

TSD will not document corrections made by Pechan to these original NONROAD model estimates, since they were replaced for Version 3.

b. Data input summary spreadsheets for State review

As mentioned above for NONROAD model categories, Pechan prepared the MANE-VU emission estimates using EPA's final NMIM/NONROAD2005 model. An important QA step in running NONROAD is to ensure that the inputs used for fuel specifications and temperatures for a given county and month in 2002 are representative. As such, Pechan compiled the RVP, percent oxygen, and gasoline sulfur inputs reported by NMIM2005 by county and month for States to review. If a State had previously submitted input data for the MANE-VU onroad inventory, these data were proposed in lieu of NMIM data. States either confirmed use of the default NMIM/onroad MANE-VU inputs, or provided alternate data in the specified format to replace the proposed inputs. Pechan updated the *gasoline* table in the NMIM county database to add in new gasoline profiles to reflect revised fuel input values provided by States. These profiles were then cross-referenced to the appropriate county and month in a separate table called *countyyearmonth*. Pechan performed QA checks of these NMIM county database tables for each State to ensure that the correct fuel data were input by county and by month as requested by the State.

c. QA of final mass emissions

After performing QA of the inputs, Pechan ran NMIM/NONROAD2005 at the county and monthly level for 2002 and generated the results in NIF 3.0. As a QA step, Pechan ran EPA's NIF 3.0 QA software tool on the NIF 3.0 files. Errors identified were resolved and checked to ensure they were corrected in the final files.

As part of final processing of the inventories, and to assist in tracking revisions and preparing emission summaries, Pechan added the following NIF plus fields to each table:

TblCE : State FIPS, County FIPS, Data Source, Revision Date
TblEM : State FIPS, County FIPS, Data Source, Revision Date, CAP/HAP, Year, Emission Ton Value, Emission Type Period
TblEP : State FIPS, County FIPS, Data Source, Revision Date
TblPE : State FIPS, County FIPS, Data Source, Revision Date
TblTR : State FIPS, County FIPS, Revision Date

Data source codes are included to document the origin of the emissions data, which assists in tracking and quality-assuring revisions made to the emission estimates. Table IV-3 provides a listing of the data source codes included in the MANE-VU nonroad inventories, as well as a definition of each code. State FIPS and County FIPS are separated out to assist in developing area-specific emission summaries, and the Emission Ton Value places all emissions on the same basis. The Emission Type Period describes the temporal basis of the estimates (in this case, they are all annual). Finally, the Revision Date tracks when record-specific changes are made.

Table IV-3. Data Source Code Descriptions

Data Source Code	Description
E-02-F	E = EPA-generated data; -02 = year 2002; -F = emissions are carried forward for inclusion in the 2002 base year
E-02-X	E = EPA-generated data; -02 = year 2002; -F = emissions are not grown or carried forward
P-02-X	P = RPO-generated data; -02 = year 2002; -X = emissions are not grown or carried forward
S-02-X	S = State data; -02 = year 2002 data; -X = emissions are not grown or carried forward

3. Version 3 Emission Summaries

Table IV-4 presents a summary of the annual 2002 nonroad sector pollutant emissions for each MANE-VU State, as well as a regional total. These emissions include SCCs for all NONROAD model engines, as well as aircraft, commercial marine vessel, and locomotive categories, where applicable, for each State. Table IV-5 presents the emission results for NONROAD model equipment only, while Table IV-6 provides emission estimates for aircraft, commercial marine vessel, and locomotive categories separately.

Table IV-4. Annual 2002 Nonroad Sector Emissions by MANE-VU State (Tons/Year)

State	CO	NH_3	NO_x	PM10-PRI	PM25-PRI	SO_2	VOC
Connecticut	276,773.0	16.6	25,460.2	1,952.1	1,793.9	2,087.4	33,880.2
Delaware	68,782.0	5.2	16,226.5	1,021.4	925.6	3,983.3	8,010.1
District of Columbia	18,844.7	2.4	3,571.3	310.2	298.7	375.4	2,072.5
Maine	153,423.6	11.4	9,820.4	1,436.8	1,329.4	916.8	31,144.1
Maryland	437,400.3	28.2	37,472.2	4,936.0	4,357.1	7,941.6	56,330.4
Massachusetts	461,514.3	28.2	42,768.5	3,531.2	3,226.4	3,791.2	56,748.5
New Hampshire	130,782.2	9.1	9,912.1	1,057.8	965.4	891.0	22,376.5
New Jersey	704,396.4	43.0	63,479.0	5,495.1	4,997.2	15,686.0	83,918.9
New York	1,233,968.3	79.3	109,878.3	9,605.3	8,820.9	12,919.7	157,611.7
Pennsylvania	931,978.0	55.0	103,824.2	9,737.9	8,440.1	7,915.0	102,331.0
Rhode Island	73,012.7	4.1	5,001.5	500.2	443.1	377.2	7,779.7
Vermont	62,248.1	4.5	4,217.1	529.9	485.8	372.1	10,547.6
Total MANE-VU	**4,553,123.5**	**286.9**	**431,631.3**	**40,113.9**	**36,083.6**	**57,256.6**	**572,751.3**

Table IV-5. Annual 2002 NONROAD2005 Model Emissions by MANE-VU State (Tons/Year)

State	CO	NH_3	NO_x	PM10-PRI	PM25-PRI	SO_2	VOC
Connecticut	274,387.6	16.6	17,897.0	1,712.9	1,577.6	1,376.6	33,519.0
Delaware	65,954.1	4.9	5,798.3	570.4	525.1	513.0	7,530.5
District of Columbia	18,774.9	2.4	3,066.4	298.4	287.8	341.3	2,052.9
Maine	148,555.3	11.4	8,228.9	1,204.2	1,135.1	771.8	30,741.0
Maryland	424,776.8	28.2	27,789.1	3,118.7	2,870.4	2,569.2	53,035.0
Massachusetts	448,398.7	28.2	30,046.7	2,887.2	2,658.8	2,428.1	54,835.8
New Hampshire	128,571.5	9.1	8,149.5	946.8	871.7	672.7	22,237.8
New Jersey	692,547.9	43.0	43,515.2	4,285.4	3,950.5	3,524.9	81,900.4
New York	1,219,308.7	79.3	78,648.3	8,338.9	7,677.1	6,966.3	155,475.1
Pennsylvania	903,167.7	55.0	62,265.2	6,281.5	5,784.3	5,292.4	99,240.9
Rhode Island	71,573.1	4.1	4,563.9	402.8	371.1	335.5	7,698.7
Vermont	61,732.1	4.5	4,169.9	517.6	476.6	367.6	10,520.4
Total MANE-VU	**4,457,748.6**	**286.6**	**294,138.2**	**30,564.8**	**28,186.1**	**25,159.4**	**558,787.4**

Table IV-6. Annual 2002 Aircraft, Commercial Marine, and Locomotive Emissions by MANE-VU State (Tons/Year)

State	CO	NH_3	NO_x	PM10-PRI	PM25-PRI	SO_2	VOC
Connecticut	2,385.4	0.0	7,563.2	239.2	216.4	710.8	361.2
Delaware	2,827.9	0.3	10,428.2	451.1	400.5	3,470.3	479.6
District of Columbia	69.7	0.0	505.0	11.8	10.9	34.1	19.7
Maine	4,868.3	0.0	1,591.5	232.6	194.3	145.0	403.1
Maryland	12,623.5	0.0	9,683.2	1,817.3	1,486.7	5,372.3	3,295.4
Massachusetts	13,115.6	0.0	12,721.7	644.0	567.6	1,363.1	1,912.7
New Hampshire	2,210.7	0.0	1,762.5	111.0	93.7	218.3	138.6
New Jersey	11,848.5	0.0	19,963.9	1,209.7	1,046.7	12,161.1	2,018.6
New York	14,659.6	0.0	31,230.0	1,266.4	1,143.8	5,953.4	2,136.6
Pennsylvania	28,810.2	0.0	41,559.0	3,456.4	2,655.8	2,622.7	3,090.2
Rhode Island	1,439.6	0.0	437.6	97.4	72.1	41.7	81.0
Vermont	516.0	0.0	47.3	12.2	9.2	4.5	27.2
Total MANE-VU	**95,374.9**	**0.3**	**137,493.1**	**9,549.1**	**7,897.4**	**32,097.3**	**13,963.9**

B. State-Specific Methods

The following sections describe the methods used and QA issues addressed for each MANE-VU State in developing Version 3.0 of MANE-VU's nonroad sector inventory.

1. Connecticut

a. What Data Sources Were Used?

Pechan ran EPA's NMIM2005 to generate NONROAD model SCC emission estimates. Pechan incorporated Connecticut-supplied data for gasoline sulfur content and RVP into the NMIM database. Pechan used NMIM defaults for diesel sulfur content and for weight percent oxygenate values. The final input data by county and by month are summarized in Table B-1.

Aircraft and commercial marine vessel emissions are based on the preliminary 2002 nonroad NEI. In March 2006, Connecticut provided county-level emission estimates for VOC, NO_x, and CO for all line-haul and switchyard locomotive SCCs.

b. What QA Issues were Identified and Addressed?

For commercial aircraft (SCC 2275020000), PM10-PRI and PM25-PRI were not reported in the EPA's NEI. For completeness, Pechan estimated PM10-PRI emissions by applying an average PM10-PRI/NO_x emission ratio of 0.058 to available NO_x emissions. Commercial aircraft PM25-PRI emissions were estimated by multiplying PM10-PRI emissions by a particle size multiplier of 0.976 (ERG, 2004).

c. What Issues Need to be Addressed in Future Versions?

Because EPA's NEI does not include locomotive category emission estimates for Connecticut, and since Connecticut only provided emission estimates for VOC, NO_x, and CO, estimates are still missing for PM10-PRI, PM25-PRI, and SO_2.

2. Delaware

a. What Data Sources Were Used?

Pechan used NMIM2005 to generate NONROAD model SCC emission estimates. Delaware approved of the fuel inputs used in NMIM2005. The final fuel input data by county and by month are summarized in Table B-1. Delaware provided updated files listed in Table IV-7 to replace the default files used in NMIM. These included county allocation files for five nonroad categories, and a revised equipment population file with updated populations for specific SCCs.

Table IV-7. Delaware NONROAD External Data Files

County NR File Name	File Type
10000air.alo	County allocation for airport GSE
10000gc.alo	County allocation for golf carts
10000hou.alo	County allocation for lawn & garden
10000log.alo	County allocation for logging
10000rvp.alo	County allocation for land-based recreational
10000.pop	Equipment population

Pechan used Delaware's June 2004 CERR submittal as the basis for aircraft, locomotive and commercial marine vessel category estimates in the 2002 MANE-VU inventory.

i. What Revisions Were Requested by State?

In September 2004, Delaware provided corrections to the general aviation emissions (SCC 227505000) for all pollutants for Kent County to add in general aviation activity at Dover Air Force Base.

b. What QA Issues were Identified and Addressed?

Pechan performed QA of the file, and revised the file to address QA issues as approved by Delaware. Commercial aircraft (SCC 2275020000) included emission estimates for all pollutants except PM25-PRI. Pechan calculated commercial aircraft PM25-PRI emissions using the assumption that 97.6% of PM10-PRI is PM25-PRI (ERG, 2004).

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

3. District of Columbia

a. What Data Sources Were Used?

Pechan developed NONROAD Model SCC emissions for District of Columbia using NONROAD2005. NONROAD2005 was used directly instead of NMIM2005 to incorporate State-supplied weight percent oxygen data. The District of Columbia also requested changes to the default NMIM RVP and gasoline values for some months. The final fuel input data by county and by month are summarized in Table B-1.

The 2002 minimum, maximum, and average hourly temperatures included in NMIM were used to calculate average monthly temperature inputs to NONROAD. Pechan developed monthly NONROAD2005 option files for the District of Columbia. Pechan ran the option files through NONROAD2005 to generate monthly emissions that were then summed to develop an annual 2002 inventory. Pechan performed additional calculations using NMIM emission factors and NONROAD2005 fuel consumption to calculate NH_3, since NONROAD does not calculate NH_3 emissions. NMIM reports NH_3 emission factors of 116 grams NH_3 per gallon gasoline for gasoline engines, and 83 grams NH_3 per gallon fuel for diesel engines.

The District of Columbia provided locomotive emissions for their nonroad sector June 2004 CERR submittal.

b. What QA Issues were Identified and Addressed?

Pechan performed QA of the file, and revised the file to address QA issues as approved by the District of Columbia. PM emissions in the inventory were not identified as either PM_{10} or $PM_{2.5}$, nor were the emissions identified as primary or filterable. The District of Columbia authorized Pechan to change PM to PM10-PRI. Locomotive PM25-PRI emissions were estimated using the assumption that 90 percent of PM_{10} is $PM_{2.5}$ (EPA, 2003b). Hydrocarbon (HC) pollutant emissions were also removed from the inventory, as this is not a valid pollutant code in NIF3.0.

Pechan added commercial marine vessel emissions from the preliminary 2002 Nonroad NEI. There are no aircraft emission estimates in the NEI for the District of Columbia, since there are not airports located in the District of Columbia.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

4. Maine

a. What Data Sources Were Used?

Pechan developed NONROAD model SCC emissions using NONROAD2005. For Maine, weight percent oxygen values were submitted based on actual fuel survey results by county and by month, but Maine had not tracked the corresponding oxygenate volume percent and market share. As such, Pechan used NONROAD2005 so that Maine's values for weight percent oxygen could be reflected. Maine also provided revisions to the RVP and gasoline sulfur values reported in NMIM2005. Pechan developed NONROAD2005 monthly option files for two county groups in Maine that shared values for all three fuel inputs (see Appendix C, Table C-1). The 2002 minimum, maximum, and average hourly temperatures included in NMIM were used to calculate average monthly temperature inputs to NONROAD. Pechan ran the option files through NONROAD2005 to generate monthly emissions that were then summed to develop an annual 2002 inventory. Pechan performed additional calculations using NMIM emission factors and fuel consumption to calculate NH_3, since NONROAD does not calculate NH_3 emissions. NMIM reports NH_3 emission factors of 116 grams NH_3 per gallon gasoline for gasoline engines, and 83 grams NH_3 per gallon fuel for diesel engines.

i. What Revisions Were Requested by State?

In October 2004, Maine provided aircraft, commercial marine vessel, and locomotive SCC emissions to be added to their inventory. Commercial marine emissions submitted by Maine only represented in-port emissions. Diesel and residual commercial marine underway emissions (SCCs 2280002200 and 2280003200) were based on EPA's 2002 preliminary NEI.

b. What QA Issues were Identified and Addressed?

PM25-PRI estimates were missing from all aircraft SCC records provided by Maine. Pechan estimated general aviation, military aircraft, and air taxi PM25-PRI emissions by multiplying PM10-PRI emissions by a particle size multiplier of 0.69 (EPA, 2003b). Commercial aircraft PM25-PRI emissions were estimated by multiplying PM10-PRI emissions by a particle size multiplier of 0.976 (ERG, 2004). In-port commercial marine emissions (SCC 2280002100) were missing estimates for PM10-PRI and PM25-PRI. Pechan estimated PM10-PRI emissions by applying a PM10-PRI/NO_x emission ratio of 0.042 to available NO_x emissions. PM25-PRI emissions were estimated by multiplying PM10-PRI emissions by a particle size multiplier of 0.92 (EPA, 2003b).

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

5. Maryland

a. What Data Sources Were Used?

Pechan used NMIM2005 to prepare NONROAD model SCC emission estimates. Maryland reviewed the default NMIM inputs and provided revisions to the input values for RVP and weight percent oxygen for all months. Maryland requested that a value of 2.1 percent oxygen be used for all counties and months. This weight percent value was then converted to a volume percent of 11.8 percent for use in NMIM, assuming MTBE was the only oxygenate. In addition, gasoline sulfur content revisions were incorporated into NMIM for select counties for the months of April through September. The final fuel input data by county and by month are summarized in Table B-1.

Maryland also provided updated files listed in Table IV-8 to replace the default files used in NMIM. These included county allocation files for several nonroad categories.

Table IV-8. Maryland NONROAD External Data Files

County NR File Name	File Type
24000pop.alo	County allocation for several nonroad categories (population)
24000con.alo	County allocation for construction
24000hou.alo	County allocation for lawn & garden

Pechan used Maryland's nonroad sector CERR submittal as the basis for the MANE-VU inventory for the aircraft, locomotive and commercial marine vessel categories.

i. What Revisions Were Requested by State?

In September 2004, Maryland provided revised aircraft and commercial marine vessel emission estimates. Pechan replaced the aircraft and commercial marine vessel emissions from their CERR submittal with the revised emissions.

b. What QA Issues were Identified and Addressed?

Pechan performed QA of the file, and revised the file to address QA issues as approved by Maryland. Maryland did not provide PM25-PRI aircraft emissions in their inventory. Pechan estimated general aviation, military aircraft, and air taxi PM25-PRI emissions by multiplying PM10-PRI emissions by a particle size multiplier of 0.69 (EPA, 2003b). Commercial aircraft PM25-PRI emissions were estimated by multiplying PM10-PRI emissions by a particle size multiplier of 0.976 (ERG, 2004).

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

6. Massachusetts

a. What Data Sources Were Used?

Pechan used NMIM2005 to generate NONROAD model SCC emission estimates. Massachusetts reviewed the NMIM inputs and approved of the fuel input values for RVP and gasoline sulfur content. NMIM2005 reported a weight percent oxygen of 2.1 percent for all months for all counties in Massachusetts, and the State requested a value of 1.5 percent be used for all counties from October through April. This weight percent value was then converted to a volume percent of 8.4 percent for use in NMIM, given that MTBE was the only oxygenate. Final fuel input data by county and by month are presented in Table B-1.

Massachusetts provided annual emissions for aircraft, locomotive and commercial marine vessel categories for their nonroad sector CERR submittal. These inventories included all CAP.

i. What Revisions Were Requested by State?

Massachusetts requested that Pechan incorporate revisions supplied for annual emissions for in-port diesel commercial marine (SCC 2280002010) for Dukes County (25007).

b. What QA Issues were Identified and Addressed?

Pechan changed the aircraft SCC "2275050000" to "2275000000," since Massachusetts verified that this emission record represents all aircraft types, not just general aviation.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

7. New Hampshire

a. What Data Sources Were Used?

Pechan used NMIM2005 to generate NONROAD model SCC emission estimates. New Hampshire reviewed and approved of the fuel inputs used in NMIM2005. See Table B-1 for a summary of the final fuel input data by county and month.

Pechan used New Hampshire's nonroad sector CERR submittal as the basis for the MANE-VU aircraft and locomotive inventory. Pechan added commercial marine vessel emissions from the preliminary 2002 Nonroad NEI.

b. What QA Issues were Identified and Addressed?

Pechan performed QA of the file, and revised the file to address QA issues as approved by New Hampshire. New Hampshire did not provide PM_{10} and $PM_{2.5}$ aircraft emissions in their inventory. New Hampshire authorized Pechan to develop aircraft PM_{10} emissions for all aircraft types by applying an average PM10/NO_x emission ratio to the aircraft NO_x emissions in their inventory. The PM_{10}/NO_x ratios used were 3.819 for military and air taxi, 3.642 for general aviation, and 0.058 for commercial aircraft. Pechan estimated general aviation, military aircraft, and air taxi PM25-PRI emissions by multiplying PM10-PRI emissions by a particle size multiplier of 0.69 (EPA, 2003b). For commercial aircraft, Pechan estimated PM25-PRI emissions using the assumption that 97.6% of PM_{10} is $PM_{2.5}$ (ERG, 2004).

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

8. New Jersey

a. What Data Sources Were Used?

Pechan used NMIM2005 to generate NONROAD model SCC emission estimates. New Jersey approved of the default fuel inputs used in NMIM2005. See Table B-1 for a summary of the final fuel input data by county and month. New Jersey provided an updated data input file containing revised equipment populations (34000.pop) for specific SCCs for the NMIM model runs.

Pechan used New Jersey's nonroad sector CERR submittal as the basis for the aircraft, locomotive and commercial marine vessel categories. These inventories included all CAPs.

b. What QA Issues were Identified and Addressed?

Pechan performed QA of the file, and revised the file to address QA issues as approved by New Jersey. The only QA issue identified was the inclusion of carbon dioxide (CO_2) in the inventory, which is not a valid pollutant code in NIF3.0, so these records were removed.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

9. New York

a. What Data Sources Were Used?

Pechan used NMIM2005 to generate NONROAD model SCC emission estimates. New York reviewed the default NMIM inputs and provided revisions to the input values for RVP and gasoline sulfur for all months. New York also requested revisions to weight percent oxygen values for all counties and months. These weight percent values were then converted to a volume percent for use in NMIM, based on MTBE as the only oxygenate for all counties, with the exception of four counties. These included Cattaraugus, Chautauqua, Erie, and Niagara counties, which use ETOH as the oxygenate. The final fuel input data by county and by month are summarized in Table B-1.

For the aircraft and locomotive categories, Pechan used emissions reported in the preliminary 2002 Nonroad NEI.

i. What Revisions Were Requested by State?

In October 2004, New York provided commercial marine vessel emissions to be added to their inventory. New York did not provide PM-2.5 commercial marine vessel emissions for some counties in their inventory. Pechan estimated the commercial marine vessel PM25-PRI emissions from PM10-PRI using the assumption that 92% of PM_{10} is $PM_{2.5}$ (EPA, 2003b).

b. What QA Issues were Identified and Addressed?

Commercial aircraft (SCC 2275020000) emissions for PM10-PRI and PM25-PRI were not reported in the EPA's preliminary 2002 NEI. Pechan estimated PM10-PRI emissions by applying a PM10-PRI/NO_x emission ratio of 0.058 to available NO_x emissions for this SCC. Commercial aircraft PM25-PRI emissions were estimated by multiplying PM10-PRI emissions by a particle size multiplier of 0.976 (ERG, 2004).

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

10. Pennsylvania

a. What Data Sources Were Used?

Pechan used NMIM2005 to generate NONROAD model SCC emission estimates. Pennsylvania approved of the fuel inputs provided, which were based on the onroad MOBILE6 inputs. Since these differed from the values in NMIM2005, Pechan updated the NMIM profiles accordingly. See Table B-1 for a summary of the final fuel input data by county and month. Pennsylvania provided one county allocation file for the lawn and garden category (42000hou.alo) to replace the default file used in NMIM.

Pennsylvania submitted an aircraft, locomotive, and commercial marine vessel emissions inventory to MANE-VU after the CERR submittal date.

i. What Revisions Were Requested by State?

In August 2005, Pennsylvania provided Pechan with county-level updates to SCC 2285002006 (Line Haul Locomotives: Class I Operations) emissions for all pollutants. Pechan updated all emission records for this SCC in Pennsylvania's inventory.

b. What QA Issues were Identified and Addressed?

Pennsylvania authorized Pechan to remove the CO_2 emission records from their inventory. In addition, the following data augmentation was performed to add missing SCCs and pollutants. Pennsylvania did not provide commercial aircraft emissions in their inventory. Pechan added commercial aircraft emissions from the 2002 preliminary NEI to Pennsylvania's inventory. Pennsylvania did not provide PM10-PRI and PM25-PRI aircraft emissions in their inventory. Pechan developed aircraft PM_{10} emissions for all aircraft types by applying an average PM_{10}/NO_x emission ratio to Pennsylvania's available aircraft NO_x emissions. The PM_{10}/NO_x ratios used were 3.819 for military and air taxi, 3.642 for general aviation, and 0.058 for commercial aircraft. Pechan estimated general aviation, military aircraft, and air taxi PM25-PRI emissions by multiplying PM10-PRI emissions by a particle size multiplier of 0.69 (EPA, 2003b). For commercial aircraft, Pechan estimated PM25-PRI emissions using the assumption that 97.6% of PM_{10} is $PM_{2.5}$ (ERG, 2004).

Pennsylvania also did not provide SO_2 general aviation and air taxi emissions in the inventory. Pechan estimated the SO_2 emissions by applying a SO_2/NO_x emission ratio to the general aviation and air taxi NO_x emissions, using ratios of 0.154 and 0.095, respectively.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

11. Rhode Island

a. What Data Sources Were Used?

Pechan used NMIM2005 to generate NONROAD model SCC emission estimates. Rhode Island approved of the fuel inputs used in NMIM2005. See Table B-1 for a summary of the final fuel input data by county and month. Rhode Island provided a revised equipment population file (44000.pop) with updated populations for specific SCCs to replace the default file used in NMIM.

Rhode Island provided emissions for aircraft, locomotive and commercial marine vessel categories for their nonroad sector CERR submittal.

i. What Revisions Were Requested by State?

Rhode Island provided updates in September 2004 to their county-level railroad equipment emissions. The new emissions fall under SCC 2285002005 and replace all line haul locomotive emissions provided in their CERR submittal. Emission estimates for yard locomotives were also provided (SCC 2285002010).

b. What QA Issues were Identified and Addressed?

Pechan performed QA of the file, and revised the file to address QA issues as approved by Rhode Island.

PM_{10} was not identified as either primary or filterable. Rhode Island authorized Pechan to change it to PM10-PRI. To avoid double counting, Pechan removed the following SCCs from Rhode Island's inventory: 2275000000, 2280002000, 2280002020, 2280003000, and 2280003020. These emissions are accounted for under more specific SCCs for aircraft, and more aggregate SCCs for commercial marine.

Rhode Island did not provide PM10-PRI and PM25-PRI aircraft emissions in their inventory. Pechan developed aircraft PM_{10} emissions for all aircraft types by applying an average PM_{10}/NO_x emission ratio to the aircraft NO_x emissions in their inventory. The PM_{10}/NO_x ratios used were 3.819 for military and air taxi, 3.642 for general aviation, and 0.058 for commercial aircraft. Pechan estimated general aviation, military aircraft, and air taxi PM25-PRI emissions by multiplying PM10-PRI emissions by a particle size multiplier of 0.69 (EPA, 2003b). For commercial aircraft, Pechan estimated PM25-PRI emissions using the assumption that 97.6% of PM_{10} is $PM_{2.5}$ (ERG, 2004).

Rhode Island did not provide yard locomotive, and commercial marine vessel PM25-PRI emissions in their inventory. Pechan estimated the yard locomotive PM25-PRI emissions from PM10-PRI using the assumption that 90% of PM_{10} is PM25 (EPA, 2003b). Pechan estimated the commercial marine vessel PM25-PRI emissions from PM10-PRI using the assumption that 92% of PM_{10} is $PM_{2.5}$ (EPA, 2003b).

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

12. Vermont

a. What Data Sources Were Used?

Pechan developed NONROAD model SCC emissions for Vermont using NMIM2005. Vermont approved of the default fuel input values used in NMIM2005 for weight percent oxygen, but requested that the RVP and gasoline sulfur values reflect values used for onroad mobile source emissions.

Pechan added aircraft emissions for Vermont from the preliminary 2002 Nonroad NEI.

b. What QA Issues were Identified and Addressed?

Commercial aircraft (SCC 2275020000) emissions for PM10-PRI and PM25-PRI were not reported in the EPA's preliminary 2002 NEI. Pechan estimated PM10-PRI emissions by applying an average PM10-PRI/NO_x emission ratio of 0.058 to available NO_x emissions. Commercial aircraft PM25-PRI emissions were estimated by multiplying PM10-PRI emissions by a particle size multiplier of 0.976 (ERG, 2004).

c. What Issues Need to be Addressed in Future Versions?

Note that there are no locomotive or commercial marine vessel emissions in the NEI for Vermont. Where activity for any of these SCCs occurs in Vermont, these categories are not represented in the State's inventory.

CHAPTER V – ONROAD SOURCES

A. General Methods for All States

This section provides an overview of the data sources and QA steps used in preparing the 2002 onroad sector inventory for the MANE-VU States and in preparing the corresponding modeling inputs for the MANE-VU Version 3 modeling inventory. The onroad sector is comprised of all motorized vehicles that travel on the public highways including passenger cars, light-duty trucks, minivans, sport utility vehicles, heavy-duty trucks, and buses. It should be noted that, unlike the other emission sectors, the modeling inventory inputs for the onroad sector do not include any emissions data. The primary modeling inputs for the onroad sector instead are the activity inputs (vehicle miles traveled (VMT)) and SMOKE-formatted MOBILE6 input files. The SMOKE model then generates full MOBILE6 input files using the MOBILE6 inputs, speed inputs, and meteorological inputs for the episode(s) to be modeled, runs the MOBILE6 emission factor model to calculate the appropriate emission factors, and calculates emissions using the supplied VMT and additional temporal allocation factors for the VMT.

1. Data Sources

a. Source of default model data

The MANE-VU 2002 onroad emissions inventory was compiled from data supplied by the MANE-VU State agencies in the form of onroad emissions input data or emissions inventories either directly to MANE-VU or to EPA through their CERR submittal. States provided information in one or more of the following ways: (1) an onroad emission inventory submittal to EPA, (2) MOBILE6 inputs and VMT data in NMIM format to EPA, (3) portions of MOBILE6 inputs or full MOBILE6 input files and supporting files plus VMT to EPA, or (4) portions of MOBILE6 inputs or full MOBILE6 input files and supporting files plus VMT to MANE-VU. Different procedures were followed in developing the MANE-VU 2002 onroad emission inventory depending upon how the data were submitted.

As discussed above, the primary data needed in preparing the inputs for the onroad modeling files were the VMT data and MOBILE6 input files. All of the MANE-VU States provided VMT data, which were incorporated in the SMOKE modeling. The level of detail of the supplied VMT data and any additional processing of the VMT data are discussed individually by State, below, in Section B: State-Specific Methods. Therefore, no default data were needed for the VMT inputs. Default model inputs for the SMOKE MOBILE6 input files were needed in some cases. The source of default information to be included in these input files was the NMIM national county database, as this was also the default source of data for EPA in preparing the 2002 NEI. This database includes information on monthly fuel data by county, control program information by county, such as inspection and maintenance (I/M) program inputs, and other fleet information, such as vehicle registration distributions, that may have been supplied by the States. Additionally, vehicle speed information is needed in the SMOKE modeling files. Some States supplied this information. In cases where no speed data were supplied, the default speeds used by EPA in calculating the NEI were used. These speeds differ by road class group and by vehicle class group.

For the SMOKE modeling, Pechan did not provide any ambient data such as temperature or humidity. Instead, the SMOKE model needs meteorological input data specific to the episode(s) being modeled. Thus, although the SMOKE MOBILE6 input files do include temperature data and in some cases humidity data, these inputs will be replaced by the SMOKE model with the appropriate episode-specific data.

b. Model inputs and revisions provided by States

The model inputs and revisions provided by the States are discussed in detail in Section B, below. These inputs include VMT data, VMT temporal data, vehicle speeds, I/M program inputs, registrations distributions, and other MOBILE6 input data.

c. Model inputs provided vs. model inputs used

Pechan prepared the following model input files for Version 3 of the MANE-VU modeling inventory:

- MANEVU_2002_mbinv_02022006.txt—contains VMT and speeds by county and SCC;
- MANEVU_2002_mtpro_02022006.txt—contains VMT temporal profiles;
- MANEVU_2002_mtref_02022006.txt—contains cross references between temporal profiles and county/SCC;
- MANEVU_2002_vmtmix_02022006.txt—contains VMT vehicle mix fractions;
- MANEVU_2002_mcref_02022006.txt—contains cross reference between MANE-VU counties and the SMOKE MOBILE6 input files;
- MANEVU_2002_mvref_02022006.txt—contains general county-level information for SMOKE;
- MANEVU_2002_spdpro.txt—contains hourly speed profiles (SPDPRO);
- MANEVU_2002_spdref.txt—contains cross references between speed profiles and MANE-VU county/SCC;
- MANEVU_2002_mcodes.txt—contains information on SCCs used in MBINV file;
- MANEVU_SMOKE_M6Inputs_MA_NJ_02022006.zip—contains monthly SMOKE-formatted MOBILE6 input files for Massachusetts and New Jersey, updated for Version 3;
- MANEVU_2002_SMOKE_M6_InputFiles032004.zip—contains monthly SMOKE-formatted MOBILE6 input files for all MANE-VU States. Files for Massachusetts and New Jersey from this zip file should be replaced by the Version 3 files dated 02/02/2006.
- MANEVU_2002_SMOKE_M6_ExternalFiles.zip—contains external data files called by the SMOKE MOBILE6 input files.

2. What Quality Assurance Steps were Performed?

This section provides a brief summary of the QA steps and processes that were performed in the development of the onroad sector modeling inputs for MANE-VU. The initial QA procedures were performed on the emissions and input data used to calculate the MANE-VU 2002 onroad emission inventory. Some of these QA procedures are also relevant here to the modeling inventory as many of the inputs are either the same or start with common information.

For States submitting onroad emission inventories to EPA, Pechan performed QA checks on the State-provided emission inventory data to ensure completeness, referential integrity, and correct formatting of the data. Where necessary as a result of these QA checks, and with the approval of the affected State, Pechan revised the inventories to meet the necessary inventory standards. For the modeling inventory, the VMT checks included in these QA checks are relevant. Note that a Quality Assurance Plan was prepared prior to initiating work on Version 1 (MANE-VU, 2003). This plan was applied during development of all three versions of the MANE-VU inventory.

a. Data input summary spreadsheets for State review

In reviewing the data submitted for both the annual onroad inventory and the onroad modeling files, Pechan prepared a State QA report for each State. These reports were in the form of Excel spreadsheets. In each of the State QA reports, a page was included that summarized the modeling inputs. This included MOBILE6 input parameters, such as I/M data, registration data, and fuel data. Columns were included indicating the data file name, data coverage (e.g., statewide or for specific counties), data source, any comments regarding the data, an indication of whether any guidance was requested from the State agency before proceeding, and columns for State agency approval of the listed inputs. These reports were provided to each State agency and the State could either approve the inputs summarized or provide an alternate data source or calculation method. For States that had submitted emission inventories in NIF format, results of the NIF QA checks were also included in these State QA reports for the states to review and approve and provide alternate data or methods. This table also include information on the VMT data source and any proposed methodologies needed for processing the VMT.

b. Responses from State Agencies

The appropriate State agency staff reviewed the State QA reports and provided direction for correcting QA issues either in the QA Summary Report Excel file or via e-mail. The modeling inputs were then revised to incorporate responses from the agencies.

3. Version 3 Emission Summaries

Table V-1 presents a summary of the annual 2002 Version 3 MANE-VU onroad sector pollutant emissions for each MANE-VU State, as well as a regional total. Differences between these Version 3 annual emission totals and the Version 2 totals documented in the January 2005 MANE-VU mobile sources inventory report are the result of updated data provided by New Jersey and Massachusetts. Emissions for the remaining states have not changed. It should be noted that these emission results are from the annual inventory modeling. These will differ from the results obtained by the SMOKE onroad modeling. Additionally, the emissions in this table do not reflect VMT updates from Vermont that were provided after the Version 2 MANE-VU annual inventory had been calculated, but were included in the SMOKE Version 2 and Version 3 modeling inputs.

Table V-1. Annual 2002 Onroad Sector Emissions by MANE-VU State (Tons/Year)

State	VOC	NO_x	CO	SO_2	PM10-PRI	PM25-PRI	NH_3
Connecticut	31,755.3	68,816.2	562,124.0	1,666.9	1,580.0	1,041.6	3,293.9
Delaware	10,563.8	21,340.5	160,760.4	583.9	581.1	414.9	902.8
District of Columbia	4,895.3	8,902.0	66,017.6	271.1	222.0	153.0	397.8
Maine	23,037.4	54,686.8	410,957.8	1,803.9	1,239.1	934.4	1,467.5
Maryland	61,846.7	122,210.0	1,000,762.8	4,057.6	3,168.3	2,200.4	5,594.3
Massachusetts	57,185.5	143,367.6	1,039,100.1	4,398.8	3,407.5	2,409.9	5,499.1
New Hampshire	16,762.3	33,283.0	306,792.5	776.9	814.3	561.8	1,447.0
New Jersey	89,752.9	152,076.1	1,273,513.1	3,648.6	3,725.3	2,469.0	7,382.0
New York	287,845.2	319,732.5	3,711,149.6	10,639.5	8,457.5	5,897.7	14,680.9
Pennsylvania	176,090.3	346,471.5	2,784,196.5	10,924.1	7,351.5	5,331.2	10,532.3
Rhode Island	12,537.8	16,677.2	186,196.8	425.3	345.1	210.5	852.6
Vermont	17,287.8	20,669.9	248,247.6	893.8	669.6	482.8	934.1
Total MANE-VU	**789,560.3**	**1,308,233.3**	**11,749,818.8**	**40,090.5**	**31,561.3**	**22,107.2**	**52,984.3**

B. State-Specific Methods

The following sections describe what modeling inputs were used for each State and how these inputs were developed.

1. Connecticut

a. What Data Sources Were Used?

Table V-2 summarizes the onroad SMOKE input files that were prepared containing information for the State of Connecticut. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

The VMT inputs provided by Connecticut were in the form of three sets of data. This included a file with VMT by county and four road types (Expressway, Arterial/Collector, Local, and Ramp), a set of Statewide VMT mixes at the 16 vehicle type-level for each of the four Connecticut road types, and a Statewide hourly VMT distribution file. Additional data provided by Connecticut showing the correspondence between the four Connecticut road types and the 12 Highway Performance Monitoring System (HPMS) road types were used to first distribute the county VMT to the 12 road types. Average daily miles were converted to annual miles by multiplying the average daily miles by 365. Pechan then developed a simple MOBILE6 input file that used the Connecticut registration distribution and with a separate scenario for each of the VMT mixes provided at the 16 vehicle type level. Pechan used the resulting MOBILE6 output file to extract the 28 vehicle type VMT mix corresponding to each of the four Connecticut road types. The VMT data by county and 12 road types were then multiplied by the 28 vehicle type VMT fractions to obtain a VMT file at the 28 vehicle type level and 12 road type level by county (for use in calculating the annual emission inventory). VMT from these 28 vehicle types were then aggregated to the 12 vehicle types needed for the SMOKE MBINV input file. The VMT mix fractions by vehicle type for each county and road type were also calculated for inclusion in the SMOKE VMTMIX file.

Table V-2. Connecticut Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	Level of Detail	Data Source
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	CT
Speeds	MANEVU_2002_mbinv_02022006.txt	Road type/3 vehicle groups	Default NEI
Speed profiles	MANEVU_2002_spdpro.txt and MANEVU_2002_spdref.txt	County/hour/road type	CT
VMT mix	MANEVU_2002_vmtmix_02022006.txt	Statewide/road type	CT
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

For Connecticut, speed information is contained in both the MBINV SMOKE file as well as in the SMOKE speed profile (SPDPRO) and speed cross reference file (SPDREF) files. The speed information contained in the MBINV file is simply the default NEI speed data. The actual speed data to be used in the modeling inventory for Connecticut are contained in the SMOKE SPDPRO and SPDREF. The speed data from these two files should overwrite the default speed information contained in the MBINV file during the SMOKE modeling. The data used to develop the speed profiles were provided by Connecticut in the form of NMIM speed input files with the fraction of VMT occurring within each of 14 speed bins. These speed distributions differ by hour of day and by freeways versus arterials and collectors. Separate speed distribution files were provided by Connecticut for each county. Pechan then converted these speed data into the speed profile format needed for SMOKE—hourly average speeds by county and the two specified road types.

Connecticut provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- Statewide registration distribution;
- Hourly VMT distributions;
- Statewide I/M program inputs and Anaerobic Thermal Processor (ATP); and
- RVP and fuel program data.

The data submitted by Connecticut indicated that Federal Northern reformulated gasoline is in place in the State, with an ozone season RVP of 6.8 pounds per square inch (psi). Based on the NMIM modeling that was performed for the annual emission inventory, the reformulated gasoline program was modeled in the SMOKE MOBILE6 input files using the combination of the FUEL PROGRAM: 4 command (indicating user-supplied gasoline sulfur inputs), RVP command, and the OXYGENATED FUELS command. The monthly oxygenated fuel and gasoline sulfur inputs, and the non-ozone season monthly RVP values were obtained from the

NMIM national county database for Connecticut. During the ozone season months, the RVP value submitted by Connecticut of 6.8 psi was modeled. The fuel data obtained from NMIM are the same for all counties in Connecticut, except Fairfield, which shows different fuel properties, but all represent reformulated gasoline. These values for both Fairfield and the remaining counties differed by season (i.e., the ozone season from May through September, transition months of March, April, October, and November, and the winter months of December, January, and February). Statewide diesel sulfur values modeled from NMIM were 367 ppm sulfur in the summer months (June, July, and August), 340 ppm sulfur in the winter months (December, January, and February), and 353 ppm sulfur in the spring and fall months.

Data provided by Connecticut indicated that the State follows the OTC low emission vehicle (LEV) program vehicle implementation schedule. Therefore, the OTC-LEV program LEV implementation schedule was included in the MOBILE6 SMOKE input files, starting implementation in the 1999 model year followed by a full implementation of the National LEV program in the 2001 model year.

b. What QA Issues were Identified and Addressed?

No QA issues were identified for Connecticut.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

2. Delaware

a. What Data Sources Were Used?

Table V-3 summarizes the onroad SMOKE input files that were prepared containing information for the State of Delaware. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Delaware provided VMT data in the form of the NEI NIF PE table as well as in the NMIM BaseYearVMT table format. Additionally, Delaware provided monthly VMT fractions developed from VMT counts on a variety of road types. These monthly VMT fractions were provided for each of the Delaware counties. Since the data in the NEI NIF PE table were at the level of detail needed for the SMOKE MBINV file, the format of the VMT data was simply converted from the NIF format to the SMOKE MBINV format. Similarly, the monthly VMT fractions were converted to the profile format needed in the SMOKE MTPRO file, with the appropriate cross references in the MTREF file. The average speeds provided by Delaware at the county/road type level were included in the SMOKE MBINV file.

Table V-3. Delaware Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	Level of Detail	Data Source
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	DE
Speeds	MANEVU_2002_mbinv_02022006.txt	County/road type	DE
VMT mix	MANEVU_2002_vmtmix_02022006.txt	County/road type	
Temporal profiles	MANEVU_2002_mtpro_02022006.txt and MANEVU_2002_mtref_02022006.txt	Monthly by county/road type	DE
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

The fuel data submitted by Delaware was based on the NMIM defaults with the NMIM October data replaced by the NMIM November data. The reformulated gas fuel parameters were modeled in the SMOKE MOBILE6 input files by using the combination of the OXYGENATED FUELS, FUEL RVP, and FUEL PROGRAM (for gasoline sulfur contents) commands for each month. Statewide diesel sulfur values modeled from NMIM were 300 ppm sulfur in the summer months (June, July, and August), 280 ppm sulfur in the winter months (December, January, and February), and 290 ppm sulfur in the spring and fall months.

Data provided by Delaware indicated that the State follows the OTC-LEV program vehicle implementation schedule. Therefore, the OTC-LEV program LEV implementation schedule was included in the MOBILE6 SMOKE input files, starting implementation in the 1999 model year followed by a full implementation of the National LEV program in the 2001 model year.

b. What QA Issues were Identified and Addressed?

No QA issues were identified for Delaware.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

3. District of Columbia

a. What Data Sources Were Used?

Table V-4 summarizes the onroad SMOKE input files that were prepared containing information for the District of Columbia. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-4. District of Columbia Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	Level of Detail	Data Source
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	DC
Speeds	MANEVU_2002_mbinv_02022006.txt	Road type	DC
VMT mix	MANEVU_2002_vmtmix_02022006.txt	Road type	DC
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

The District of Columbia provided 2002 VMT data in the form of the NMIM BaseYearVMT table. This table included VMT at the 28 vehicle type level for each of the six urban road types in the District of Columbia. VMT from these 28 vehicle types were then aggregated to the 12 vehicle types needed for the SMOKE MBINV input file. The VMT mix fractions by vehicle type for each county and road type were also calculated for inclusion in the SMOKE VMTMIX file. The District also provided a spreadsheet including the daily average weighted speed by roadway class. These speeds were incorporated in the SMOKE MBINV file. The District of Columbia provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- District-wide registration distribution;
- I/M program and ATP inputs; and
- Weekday trip length distribution file.

The District of Columbia specified that the NMIM fuel program default data for the District should be used for the MANE-VU modeling. This included reformulated gasoline district wide, modeled using the FUEL RVP, and FUEL PROGRAM (for gasoline sulfur contents) commands for each month. Statewide diesel sulfur values modeled from NMIM were 329 ppm sulfur in the summer months (June, July, and August), 324 ppm sulfur in the winter months (December, January, and February), and 326 ppm sulfur in the spring and fall months.

Data provided by the District of Columbia indicated that the District follows the OTC-LEV program vehicle implementation schedule. Therefore, the OTC-LEV program LEV implementation schedule was included in the MOBILE6 SMOKE input files, starting implementation in the 1999 model year followed by a full implementation of the National LEV program in the 2001 model year.

b. What QA Issues were Identified and Addressed?

No QA issues were identified for the District of Columbia.

c. *What Issues Need to be Addressed in Future Versions?*

The SMOKE MOBILE6 files for the District of Columbia should include the OXYGENATED FUELS command to fully model reformulated gasoline in the District of Columbia. This command was inadvertently left out of the SMOKE MOBILE6 files.

4. Maine

a. *What Data Sources Were Used?*

Table V-5 summarizes the onroad SMOKE input files that were prepared containing information for the State of Maine. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-5. Maine Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	**Level of Detail**	**Data Source**
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	ME
Speeds	MANEVU_2002_mbinv_02022006.txt	County/road type	ME
VMT mix	MANEVU_2002_vmtmix_02022006.txt	Statewide/road type	Default
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

Maine provided 2002 average daily VMT by county and 12 roadway types. Maine had no information available on the distribution of VMT among vehicle types. Therefore, Pechan developed the VMT by county, roadway type, and vehicle type by using the default MOBILE6 2002 VMT mix by vehicle type. These VMT data were converted to annual VMT by multiplying the average daily VMT by 365. The MOBILE6 VMT default mix fractions by vehicle type for 2002 were included for Maine in the SMOKE VMTMIX file. Maine also provided average speed data by county and roadway type. These data were included in the SMOKE MBINV file.

Maine provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- I/M program inputs and ATP inputs for Cumberland County only; and
- Monthly average RVP data.

Statewide diesel sulfur values were obtained from the NMIM defaults for Maine. A diesel sulfur value of 390 ppm sulfur was modeled in the summer months (June, July, and August), 338 ppm sulfur in the winter months (December, January, and February), and 364 ppm sulfur in the spring and fall months.

Data provided by Maine indicated that the State follows the OTC-LEV program vehicle implementation schedule. Therefore, the OTC-LEV program LEV implementation schedule was included in the MOBILE6 SMOKE input files, starting implementation in the 1999 model year followed by a full implementation of the National LEV program in the 2001 model year.

b. What QA Issues were Identified and Addressed?

No QA issues were identified for Maine.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

5. Maryland

a. What Data Sources Were Used?

Table V-6 summarizes the onroad SMOKE input files that were prepared containing information for the State of Maryland. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Maryland submitted annual VMT data in the form of a NIF tblMobilePE table. This included VMT by county, 12 vehicle types, and 12 road types. These VMT data were then converted to the format needed for the SMOKE MBINV file. Pechan calculated VMT mix fractions from the VMT data supplied by Maryland to obtain the VMT mixes by county and road type contained in the SMOKE VMTMIX file. In addition, Maryland provided monthly VMT distribution data by road type. Pechan converted these data to the format needed for the SMOKE MTPRO and MTREF files. The same set of monthly temporal profiles were applied to all counties in Maryland. Maryland also provided a spreadsheet showing the average speed Statewide for each of the 12 roadway types. These speed data were included in the SMOKE MBINV file.

Maryland provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- County-specific registration distribution;
- County-specific diesel sales fractions;
- I/M program inputs and ATP inputs to be applied in the 14 I/M counties; and
- Statewide monthly diesel sulfur content data.

Maryland indicated that the NMIM default fuel parameters for Maryland should be used in the MANE-VU modeling. This fuel data includes reformulated gasoline in 14 of the Maryland counties. The reformulated gasoline program was modeled using the FUEL RVP, and FUEL PROGRAM (for gasoline sulfur contents) commands for each month. Maryland provided monthly Statewide diesel sulfur values. These values ranged from 455 ppm sulfur to 500 ppm sulfur. These values were included in the corresponding monthly SMOKE MOBILE6 input files.

Table V-6. Maryland Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	**Level of Detail**	**Data Source**
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	MD
Speeds	MANEVU_2002_mbinv_02022006.txt	County/road type	MD
VMT mix	MANEVU_2002_vmtmix_02022006.txt	County/road type	MD
Temporal profiles	MANEVU_2002_mtpro_02022006.txt and MANEVU_2002_mtref_02022006.txt	Statewide monthly by road type	MD
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

Data provided by Maryland indicated that the State follows the OTC-LEV program vehicle implementation schedule. Therefore, the OTC-LEV program LEV implementation schedule was included in the MOBILE6 SMOKE input files, starting implementation in the 1999 model year followed by a full implementation of the National LEV program in the 2001 model year.

b. What QA Issues were Identified and Addressed?

No QA issues were identified for Maryland affecting the modeling inventory files.

c. What Issues Need to be Addressed in Future Versions?

The SMOKE MOBILE6 files for Maryland should include the OXYGENATED FUELS command to fully model reformulated gasoline in the Maryland counties that implement the reformulated gasoline program. This command was inadvertently left out of the Maryland SMOKE MOBILE6 files.

6. Massachusetts

a. What Data Sources Were Used?

Table V-7 summarizes the onroad SMOKE input files that were prepared containing information for the State of Massachusetts. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-7. Massachusetts Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	Level of Detail	Data Source
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	MA
Speeds	MANEVU_2002_mbinv_02022006.txt	County/road type	MA
VMT mix	MANEVU_2002_vmtmix_02022006.txt	County/road type	Default
Temporal profiles	MANEVU_2002_mtpro_02022006.txt and MANEVU_2002_mtref_02022006.txt	Monthly by county	MA
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

The Version 3 MANE-VU onroad modeling for Massachusetts differed from the Version 2 modeling, based on updates provided by Massachusetts in December 2005. The primary changes for Massachusetts from Version 3 is the use of updated 2002 VMT data and vehicle speed date. Massachusetts provided a spreadsheet containing revised VMT values and vehicle speeds for 2002 by county and SCC. Pechan prepared the revised Massachusetts VMT data and the speed data in the format of the SMOKE MBINV file. Using the revised VMT data by SCC, Pechan calculated the updated VMT mixes by vehicle type for each county and road type in Massachusetts and formatted the resulting data to be included in the SMOKE VMTMIX file.

The original VMT data submitted by Massachusetts included VMT for each of the four seasons. Pechan used these data to develop monthly VMT temporal profiles. Seasonal VMT was assigned to the months in that season based on the ratio of the number of days in a specific month to the number of days in the season. Pechan then formatted the monthly temporal VMT allocation factors for inclusion in the SMOKE MTPRO and MTREF files.

Massachusetts provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- Statewide registration distribution;
- Statewide I/M program inputs and ATP inputs;
- RVP and fuel program data;
- Diesel sulfur content of 350 ppm sulfur year-round and statewide; and
- Massachusetts-specific LEV and Tier 2 implementation files.

Northern reformulated gasoline was modeled statewide throughout the State, with a RVP value of 6.7 psi during the ozone season and 13.5 psi during the remaining months, based on inputs provided by Massachusetts. The section below on QA issues for Massachusetts discusses the fuel inputs modeled in the Version 3 SMOKE MOBILE6 input files in more detail. Massachusetts provided the necessary inputs to model the State's LEV implementation schedule and Tier 2 data, which differ from the OTC-LEV program and from the default MOBILE6 Tier 2 data.

b. What QA Issues were Identified and Addressed?

In addition to the VMT updates, Pechan revised the SMOKE MOBILE6 input files for Massachusetts for Version 3. This was done because Version 2 of the MANE-VU modeling inventory was prepared using the default setting of MOBILE6 to model reformulated gasoline (i.e., using the command line "FUEL PROGRAM : 2 N"). Since the time that the Version 2 inventory was created, EPA found a bug with the sulfur content values used when the default reformulated gasoline command is used. To eliminate this problem, Pechan created revised SMOKE MOBILE6 input files for Massachusetts that model reformulated gasoline by explicitly setting the RVP, gasoline sulfur contents, and gasoline oxygen contents. The gasoline sulfur contents and gasoline oxygen contents were set according to the default parameters laid out in the MOBILE6 user's guide. The summer (May through September) sulfur content is 129 ppm in 2002 and the winter sulfur content is 279 ppm in 2002. The summer gasoline contains 2.1 percent oxygen, with MTBE as the oxygenate. The winter gasoline contains 1.5 percent oxygen in 70 percent of the fuel having MTBE as the oxygenate, and 3.5 percent oxygen in 30 percent of the fuel having ETOH as the oxygenate. The RVP values were not changed from those modeled in Version 2 (6.7 psi in the summer and 13.5 psi in the winter).

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

7. New Hampshire

a. What Data Sources Were Used?

Table V-8 summarizes the onroad SMOKE input files that were prepared containing information for the State of New Hampshire. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-8. New Hampshire Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	Level of Detail	Data Source
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	NH
Speeds	MANEVU_2002_mbinv_02022006.txt	County/road type	NH
VMT mix	MANEVU_2002_vmtmix_02022006.txt	Statewide	NH
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

The VMT inputs provided by New Hampshire were in the form of summer day VMT by county or nonattainment area and roadway type. In addition, New Hampshire provided a Statewide VMT mix distribution by 16 vehicle types in the MOBILE6 files provided by the State. Pechan then developed a simple MOBILE6 input file that used the New Hampshire Statewide registration distribution and the Statewide VMT mix by vehicle type. Pechan used the resulting MOBILE6 output file to extract the 28 vehicle type VMT mix to be applied Statewide to the county/roadway type VMT data. Summer day miles were converted to annual miles by using national data from the Federal Highway Administration’s Travel Volume Trends which provides 2002 monthly VMT for groups of road categories. Additionally, the VMT data from the three New Hampshire nonattainment areas represented four counties. To allocate these VMT by county, Pechan first totaled the VMT data from these three nonattainment areas by roadway type. Then, using ratios developed from the preliminary 2002 NEI VMT, Pechan allocated the grouped VMT by county and roadway type. With VMT for the entire State at the county/roadway type level of detail, Pechan then multiplied the VMT data by the 28 vehicle type VMT fractions to obtain a VMT file at the 28 vehicle type level and 12 roadway type level by county for use in preparing the annual onroad emission inventory. VMT from these 28 vehicle types were then aggregated to the 12 vehicle types needed for the SMOKE MBINV input file. The VMT mix fractions by vehicle type for each county and road type were also calculated for inclusion in the SMOKE VMTMIX file. New Hampshire also provided a spreadsheet including the average speed by roadway class for each county or county group. These speeds were incorporated in the SMOKE MBINV file.

New Hampshire provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- Statewide registration distribution; and
- Statewide ATP inputs.

New Hampshire specified that the NMIM fuel program default data for New Hampshire should be used for the MANE-VU modeling. This included reformulated gasoline in four counties, modeled using the FUEL RVP, and FUEL PROGRAM (for gasoline sulfur contents) commands for each month. Statewide diesel sulfur values modeled from NMIM were 400 ppm sulfur in the summer months (June, July, and August), 340 ppm sulfur in the winter months (December, January, and February), and 370 ppm sulfur in the spring and fall months.

Data provided by New Hampshire indicated that the State follows the OTC-LEV program vehicle implementation schedule. Therefore, the OTC-LEV program LEV implementation schedule was included in the MOBILE6 SMOKE input files, starting implementation in the 1999 model year followed by a full implementation of the National LEV program in the 2001 model year.

b. What QA Issues were Identified and Addressed?

Through the State QA report process, New Hampshire provided updated inputs for VMT and speeds that were incorporated in the modeling inventory inputs.

c. What Issues Need to be Addressed in Future Versions?

The SMOKE MOBILE6 files for the four New Hampshire that implement reformulated gasoline should include the OXYGENATED FUELS command to fully model the benefits reformulated gasoline. This command was inadvertently left out of the SMOKE MOBILE6 files.

8. New Jersey

a. What Data Sources Were Used?

Table V-9 summarizes the onroad SMOKE input files that were prepared containing information for the State of New Jersey. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-9. New Jersey Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	**Level of Detail**	**Data Source**
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	NJ
Speeds	MANEVU_2002_mbinv_02022006.txt	Road type/3 vehicle groups	Default NEI
VMT mix	MANEVU_2002_vmtmix_02022006.txt	County/road type	NJ
Temporal profiles	MANEVU_2002_mtpro_02022006.txt and MANEVU_2002_mtref_02022006.txt	Monthly by 3 county groups and weekday/weekend	NJ
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

Updates were made to the Version 2 MOBILE6 SMOKE inputs for New Jersey in December 2005 to create Version 3, based on revised data provided by the State. New Jersey provided the following files:

- a set of SMOKE MOBILE6 input files by county and month;
- NJ_2002_mbinv.txt file that contained revised VMT and speeds by county and SCC, generated by NJDEP in August 2005, in SMOKE format;
- amptref.m3.manevu.vistascem.032805_NJVMT.txt—a SMOKE-formatted file containing county/SCC-level temporal profile cross-references;
- amptro.m3.manevu.vistascem.032805_NJVMT.txt—a SMOKE-formatted file containing county-specific VMT temporal profiles prepared by NJDEP in August 2005; and
- zip files containing external files needed to run the SMOKE MOBILE6 files.

After an initial review of these files, Pechan did not note any differences in the SMOKE MOBILE6 files from the Version 2 files. Pechan then confirmed with New Jersey that the only changes from the Version 2 date were in the VMT data. The VMT and speed data by county and SCC in the MBINV file provided by New Jersey were copied to the MANE-VU SMOKE MBINV file, replacing the VMT and speed data from the Version 2 SMOKE MBINV file for New Jersey. The speed data included by New Jersey are the default NEI speeds by road type and vehicle type. Using the new VMT data provided by New Jersey, Pechan calculated a revised set of VMT mix fractions by vehicle type and included these in the Version 3 SMOKE VMTMIX file. Pechan pasted the temporal profiles provided for New Jersey into the SMOKE MTPRO file. This included monthly temporal profiles and diurnal temporal profiles. The diurnal temporal profiles were applied to both weekdays and weekends. Similarly the temporal cross reference data included in the file provided by New Jersey was pasted into the SMOKE MTREF file for MANE-VU Version 3.

The following New Jersey-provided were included in the monthly MOBILE6 input files for the SMOKE modeling:

- Statewide registration distribution;
- Statewide diesel sales fractions;
- Statewide I/M program and ATP inputs; and
- Diesel sulfur content data (340 ppm statewide).

Northern reformulated gasoline was modeled statewide throughout the State, using NMIM fuel program input defaults for New Jersey. The section below on QA issues for New Jersey discusses the fuel inputs modeled in the Version 3 SMOKE MOBILE6 input files in more detail.

Data provided by New Jersey indicated that the State follows the OTC-LEV program vehicle implementation schedule. Therefore, the OTC-LEV program LEV implementation schedule was included in the MOBILE6 SMOKE input files, starting implementation in the 1999 model year followed by a full implementation of the National LEV program in the 2001 model year.

b. What QA Issues were Identified and Addressed?

As discussed above for New Jersey, the Version 2 New Jersey SMOKE MOBILE6 input files modeled reformulated gasoline using the command line “FUEL PROGRAM : 2 N”, which is the default method for modeling reformulated gasoline with MOBILE6. To eliminate the effects of the MOBILE6 reformulated gasoline bug from the SMOKE MOBILE6 inputs, Pechan explicitly modeled the reformulated gasoline program in the New Jersey MOBILE6 input files by explicitly modeling the appropriate settings of the RVP, oxygenated fuel content commands, and gasoline sulfur commands. The values for oxygenated fuel settings and gasoline sulfur contents by month were extracted from the NMIM county-level database used in developing the annual emissions inventory for the MANE-VU Version 2 onroad emissions inventory.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

9. New York

a. What Data Sources Were Used?

Table V-10 summarizes the onroad SMOKE input files that were prepared containing information for the State of New York. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-10. New York Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	**Level of Detail**	**Data Source**
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	NY
Speeds	MANEVU_2002_mbinv_02022006.txt	Road type/3 vehicle groups	Default NEI
Speed profiles	MANEVU_2002_spdpro.txt and MANEVU_2002_spdref.txt	County/hour/road type	NY
VMT mix	MANEVU_2002_vmtmix_02022006.txt	County/road type	NY
Temporal profiles	MANEVU_2002_mtpro_02022006.txt and MANEVU_2002_mtref_02022006.txt	Monthly by 3 county groups	NY
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

VMT for New York was provided in the form of a NIF PE table. These VMT data were extracted and included in the SMOKE MBINV file. VMT mix fractions by vehicle type were calculated from these VMT data and included in the SMOKE VMTMIX file.

New York provided a spreadsheet with average speeds in each of four daily time periods by county and road type. Pechan converted these speed data to the SMOKE SPDPRO format, assigning the speed for a given time period to all hours included in that time period. Pechan also prepared the SMOKE SPDREF file to appropriately cross reference each county and road type to the corresponding hourly speed profile. Because these more detailed speed files were provided for New York, the average speed by road type and county in the MBINV file was populated with default NEI speeds.

New York also provided spreadsheets showing monthly VMT by county and roadtype. After processing these VMT values to develop monthly temporal factors, Pechan observed that there were only three unique monthly profiles in this data set. These three profiles were then added to the SMOKE MTPRO file. Pechan then matched each county and road type in the State to the corresponding monthly VMT profile in the SMOKE MTREF file.

New York provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- Registration distributions—one for the New York metropolitan area and one for the rest of the State;
- Diesel sales fractions—one for the New York metropolitan area and one for the rest of the State;
- Statewide mileage accumulation rate input;
- Monthly RVP data—one set for the New York metropolitan area and one for the rest of the State;
- Reformulated gasoline program inputs for affected counties modeled with MOBILE6 defaults (i.e., “FUEL PROGRAM : 2 N”);
- I/M program inputs for affected counties;
- Statewide ATP inputs;
- Hourly VMT distributions by county group;
- Start distributions by county;
- Diesel sulfur content data (400 ppm statewide).

New York also provided the necessary input files to model the State’s LEV program implementation schedule, which differs from the OTC LEV program. New York also provided MOBILE6 Tier 2 modeling files to be used along with the New York LEV program inputs. These inputs were included in the SMOKE MOBILE6 modeling.

b. What QA Issues were Identified and Addressed?

No QA issues were identified for New York affecting the modeling inventory files.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

10. Pennsylvania

a. What Data Sources Were Used?

Table V-11 summarizes the onroad SMOKE input files that were prepared containing information for the State of Pennsylvania. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-11. Pennsylvania Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	Level of Detail	Data Source
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	PA
Speeds	MANEVU_2002_mbinv_02022006.txt	County/road type	PA
VMT mix	MANEVU_2002_vmtmix_02022006.txt	County/road type	PA
Temporal profiles	MANEVU_2002_mtpro_02022006.txt and MANEVU_2002_mtref_02022006.txt	Monthly by county	PA
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

Pennsylvania provided a database file (NEIANN02.dbf) that contained the VMT and speed data by county, roadway type, and vehicle type. This included the same VMT used in the calculation of the annual onroad inventory submitted by Pennsylvania for MANE-VU. Pechan converted the data from this database file into VMT and speed data in the format of the SMOKE MBINV file. From the VMT data, Pechan calculated VMT fractions by vehicle type by county and road type for inclusion in the SMOKE VMTMIX file. Pennsylvania also provided estimates of VMT by month for each county. Pechan converted these data to monthly allocation factors in the format needed by the SMOKE MTPRO and MTREF files. A separate monthly profile was developed for each county, but applied to all road types within that county.

Pennsylvania provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- Registration distributions for each individual county;
- I/M program and ATP inputs for affected Philadelphia and Pittsburgh area counties (inputs differ for the two areas);
- Monthly RVP data for all counties including 7.8 psi RVP program from May through September for Pittsburgh counties;
- Reformulated gasoline for the 5-county Philadelphia area modeled with MOBILE6 defaults (i.e., “FUEL PROGRAM : 2 N”); and
- Diesel sulfur content data (500 ppm statewide).

Data provided by Pennsylvania indicated that the State follows the OTC-LEV program vehicle implementation schedule. Therefore, the OTC-LEV program LEV implementation schedule was included in the MOBILE6 SMOKE input files, starting implementation in the 1999 model year followed by a full implementation of the National LEV program in the 2001 model year.

b. What QA Issues were Identified and Addressed?

No QA issues were identified for Pennsylvania affecting the modeling inventory files.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

11. Rhode Island

a. What Data Sources Were Used?

Table V-12 summarizes the onroad SMOKE input files that were prepared containing information for the State of Rhode Island. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-12. Rhode Island Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	Level of Detail	Data Source
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	RI
Speeds	MANEVU_2002_mbinv_02022006.txt	County group/road type	RI
VMT mix	MANEVU_2002_vmtmix_02022006.txt	Statewide	RI
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

Rhode Island provided a spreadsheet with the 2002 VMT as well as Statewide 2002 VMT fractions by 16 vehicle types. Pechan prepared a simple MOBILE6 input file including this Rhode Island 2002 VMT mix by vehicle type and the 2002 Rhode Island registration distribution. The VMT mix in the MOBILE6 output file at the 28 vehicle type level was then used to distribute the VMT by vehicle category. The 2002 daily VMT was at the State level, broken down by the 12 roadway types. To allocate these VMT data to the county/road type level of detail, Pechan summed the VMT from the preliminary version of EPA's 2002 NEI for Rhode Island first by State and roadway type and then by county and roadway type. Pechan calculated county/roadway type VMT fractions by dividing the VMT at the county/roadway type level by the State/roadway type VMT for the same roadway type. These fractions were then multiplied by the VMT supplied by Rhode Island at the State/roadway type level of detail to obtain county/roadway type VMT data. These county/roadway type VMT data were then multiplied by the 28 vehicle type VMT fractions to obtain VMT at the level of detail needed to populate the NMIM BaseYearVMT table for calculating the annual inventory and were then summed to the 16-vehicle type level of detail for use in the SMOKE MBINV file. The data were also converted from daily VMT to annual by multiplying the average daily VMT by 365. VMT mix fractions from this final data set were then formatted in the SMOKE VMTMIX format at the State level of detail. Statewide speeds by road type, as provided by Rhode Island, were included in the SMOKE MBINV file.

Rhode Island provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- Statewide registration distribution; and
- Statewide I/M program inputs.

Data for fuel parameters were obtained from the NMIM national county database for Rhode Island. This included reformulated gasoline Statewide, modeled using the FUEL RVP, and FUEL PROGRAM (for gasoline sulfur contents) commands for each month. These values differed by season, but were consistent Statewide. Statewide diesel sulfur values modeled from NMIM were 400 ppm sulfur in the summer months (June, July, and August), 340 ppm sulfur in the winter months (December, January, and February), and 370 ppm sulfur in the spring and fall months.

The NMIM default LEV program for Rhode Island was modeled, which includes the OTC-LEV program LEV implementation schedule.

b. What QA Issues were Identified and Addressed?

No QA issues were identified for Rhode Island.

c. What Issues Need to be Addressed in Future Versions?

The Rhode Island SMOKE MOBILE6 input files did not include the OXYGENATED FUELS command. This should have been used to fully characterize the parameters of reformulated gasoline that is used Statewide in Rhode Island.

12. Vermont

a. What Data Sources Were Used?

Table V-13 summarizes the onroad SMOKE input files that were prepared containing information for the State of Vermont. This table notes the level of detail of the data included as well as the source of the original information used to create these data files.

Table V-13. Vermont Onroad Data in SMOKE Input Files

	Final MANE-VU Version 3 SMOKE Input File	Level of Detail	Data Source
VMT	MANEVU_2002_mbinv_02022006.txt	County/SCC	VT
Speeds	MANEVU_2002_mbinv_02022006.txt	Road type/vehicle group (light-duty vs. heavy-duty)	VT
VMT mix	MANEVU_2002_vmtmix_02022006.txt	County/road type	VT
Temporal profiles	MANEVU_2002_mtpro_02022006.txt and MANEVU_2002_mtref_02022006.txt	Monthly statewide	
SMOKE MOBILE6 file listing	MANEVU_2002_mcref_02022006.txt	County	
SMOKE MOBILE6 file listing	MANEVU_2002_mvref_02022006.txt	County	

Vermont submitted VMT data in the format of the NIF PE table. Vermont then provided updated VMT data for three road classifications (rural minor collectors, rural local roads, and urban local roads) in December 2004, after the time that these changes could be included in the MANE-VU annual onroad emission inventory. However, the updated VMT were included in the MANE-VU Version 3 onroad SMOKE modeling files. This VMT change resulted in a Statewide decrease in VMT from about 9.5 billion miles to about 7.8 billion miles. As a result, the SMOKE modeling performed by MANE-VU will not match the MANE-VU emission inventory for Vermont. The VMT data were converted to the SMOKE MBINV file format. VMT mix fractions were calculated from the VMT data and included in the SMOKE VMTMIX file. Vermont also provided information on the temporal allocation of VMT. From these data, Pechan prepared a monthly VMT profile for Vermont and included the data in the SMOKE MTPRO and MTREF files.

Vermont provided information on Statewide speeds by roadway type. These speeds differed for light-duty vehicles and heavy-duty vehicles. Pechan incorporated this speed information into the SMOKE MBINV file.

Vermont provided the following data that were incorporated into the monthly MOBILE6 input files for the SMOKE modeling:

- Statewide registration distribution;
- Statewide I/M program inputs; and
- RVP data.

The RVP data provided by Vermont were based on data from a local gasoline tank farm and resulted in an RVP value of 8.5 psi during the ozone season months (May through September) and 9.47 psi for the remaining months. Data for fuel parameters other than RVP (e.g., diesel and gasoline fuel sulfur content) were obtained from the NMIM national county database for Vermont. These values differed by season, but were consistent Statewide. Statewide diesel sulfur values modeled from NMIM were 300 ppm sulfur in the summer months (June, July, and August), 290 ppm sulfur in the winter months (December, January, and February), and 295 ppm sulfur in the spring and fall months.

The NMIM default LEV program for Vermont was modeled, which includes Vermont's State-specific LEV implementation schedule.

b. What QA Issues were Identified and Addressed?

Through the State QA report process, Vermont provided a missing registration data file, RVP data and revised VMT.

c. What Issues Need to be Addressed in Future Versions?

None identified by the State.

CHAPTER VI – BIOGENIC SOURCES

A. General Methods for all States

1. What Data Sources Were Used?

Biogenic emissions for the time period from January 1, 2002 – December 31, 2002 were calculated by the New York State Department of Environmental Conservation (NYSDEC) for all of the MANE-VU states using the Biogenic Emissions Inventory System (BEIS) version 3.12 integrated within SMOKE2.1. The inventory was prepared at the state-level for CO, nitrous oxide (NO), and VOC.

General information about BEIS is available at http://www.epa.gov/AMD/biogen.html while documentation about biogenic emissions processing within SMOKE2.1 is available at http://cf.unc.edu/cep/empd/products/smoke/version2.1/html/ch06s10.html and http://cf.unc.edu/cep/empd/products/smoke/version2.1/html/ch06s17.html. Note that the SMOKE documentation refers to BEIS3.09 and has not yet been updated for BEIS3.12. This affects the number of species modeled as well as the use of different speciation profiles. However, the general processing approach has not changed from BEIS3.09 to BEIS3.12. In short, this processing approach is as follows and was utilized by NYSDEC for its biogenic emission processing for MANE-VU and the OTC modeling:

- **Normbeis3** reads gridded land use data and emissions factors and produces gridded normalized biogenic emissions for 34 species/compounds. The gridded land use file utilized by NYSDEC includes the fractional coverage of 230 different land use types for each of the 172 * 172 12-km grid cells in the MANE-VU/OTC modeling domain. In a separate BEIS3.12 input file, both summer and winter emissions factors for each species/compound are provided for each of the 230 land use types. On output, **Normbeis3** generates a file `B3GRD` which contains gridded summer and winter emission fluxes for the modeling domain that are normalized to 30 °C and a photosynthetic active radiation (PAR) of 1000 $\mu mol/m^2 s$. In addition, gridded summer and winter leaf area indices (LAI) are also written to `B3GRD`.

- **Tmpbeis3** reads the gridded, normalized emissions file B3GRD and meteorological data from the MCIP-processed MM5 meteorological fields generated by the University of Maryland for MANE-VU/OTC modeling. Specifically, the following MM5/MCIP meteorological variables are used by **Tmpbeis3** to compute hour-specific, gridded biogenic emissions from the normalized emission fluxed contained in B3GRD: layer-1 air temperature (“TA”), layer-1 pressure (“PRES”), total incoming solar radiation at the surface (“RGRND”), and convective (“RC”) and non-convective (“RN”) rainfall. Additionally, the emissions for the 34 species/compounds modeled by BEIS3.12 are converted to CO, NO, and the CB-IV VOC species utilized in CMAQ via the use of the BEIS3.12-CB-IV speciation profile. Furthermore, an external file, BIOSEASON, was utilized to decide whether to use summer or winter emissions factors for any given grid cell on any given day. This file was generated by the SMOKE2.1 utility **Metscan** based on MM5 layer-1 air temperatures to determine the date of the last spring frost and first fall frost at each grid cell. Summer emission factors are used by **Tmpbeis3** for the time period between the day of the last spring frost and the day of the first fall frost at any given grid cell, and winter emission factors are used for the remaining time period. Documentation for the **Metscan** utility is available at http://cf.unc.edu/cep/empd/products/smoke/version2.1/html/ch05s07.html. An animated GIF file showing the BIOSEASON file used by NYSDEC can be found at ftp://ftp.dec.state.ny.us/dar/air_research/chogrefe/biog_reports/b3season_movie.gif.

- For reporting purposes, the hourly, speciated, gridded emissions were aggregated to the county level for each day. For any given grid cell, emissions were distributed among the counties intersecting this grid cell in proportion to the area of each of these counties within the grid cell. The area gridding surrogates needed for this aggregation are based on a file obtained from EPA via http://www.epa.gov/ttn/chief/emch/spatial/new/bgpro.2km_041604.us.gz, followed by windowing for the MANE-VU/OTC modeling domain.

2. Version 3 Emissions Summary

Table VI-1 presents a State-level summary of the annual biogenic source emissions in Version 3 of the 2002 MANE-VU inventory. The annual emissions are based on the sum of the daily emissions prepared using the modeling approach previously discussed.

Table VI-1. Version 3 2002 MANE-VU Biogenic Source Emissions by State (Tons/Year)

State	CO	NO	VOC*
Connecticut	6,889	560	64,017
Delaware	4,274	990	46,343
District of Columbia	150	30	1,726
Maine	64,936	2,018	600,205
Maryland	18,351	2,934	210,104
Massachusetts	11,594	1,257	113,958
New Hampshire	14,306	482	141,894
New Jersey	14,058	1,813	181,617
New York	63,436	8,313	492,487
Pennsylvania	59,946	8,646	585,272
Rhode Island	1,764	211	19,233
Vermont	14,745	1,142	118,377
MANE-VU	274,451	28,396	2,575,232

* VOC emissions were calculated by adding the emissions for the following pollutants: ALD2, ETH, FORM, ISOP, NR, OLE, PAR, TERB, TOL, XYL.

B. State-Specific Methods

No state-specific methods were used in Version 3 of the MANE-VU inventory for biogenic emissions.

CHAPTER VII. TEMPORAL, SPECIATION, AND SPATIAL ALLOCATION PROFILES AND PREPARATION OF SMOKE (IDA) AND RPO DATA EXCHANGE PROTOCOL (NIF 3.0) FORMATS

Table VII-1 provides a summary of the file names and documentation used for modeling inputs for Version 3 of MANE-VU's 2002 inventory for point, area, nonroad, and onroad sources. The final input files used for temporal allocation, speciation, and spatial allocation of emissions were developed for Version 1 of the 2002 inventory and delivered to MARAMA during January 2005 (MANE-VU, 2005). These files were developed starting with the latest model input files available from EPA and then revised to include updates needed for the MANE-VU region or to add SCCs and profile assignments not included in the initial EPA data sets. The files were revised between September 2004 and January 2005 to incorporate comments provided by MANE-VU. Files in Table VII-1 with a date that is later than January 2005 were prepared to support modeling for Version 3. The notes column in the table identifies the modifications made to the files if the files were changed after this date. Otherwise, files with a date later than January 2005 were either provided by a state agency or were obtained from EPA and used for modeling Version 3.

The remainder of this chapter provides a brief summary of the revisions made to the EPA data sets prepared for Version 1 of the 2002 MANE-VU inventory and subsequently carried for the modeling for Version 3. Sections A, B, and C of this chapter discuss how the temporal allocation, speciation, and spatial allocation profiles, respectively, were developed. Section D of this chapter describes how the emissions inventory data were prepared in the SMOKE (IDA) and RPO Data Exchange Protocol (NIF 3.0) Formats.

A. Temporal Profiles

1. Point and Area Sources

The most recent SMOKE temporal cross-reference files available from EPA during the summer of 2004 were used as the starting point for developing the cross-reference files for point and area sources. The following 3 classes of modifications were completed to improve the temporal allocation input files:

- Update temporal cross-reference to assign an existing profile in the default SMOKE profiles for SCCs in the MANE-VU inventory
- Create a new temporal cross-reference to an existing profile in the default SMOKE profiles for SCCs in the MANE-VU inventory; the cross-reference did not previously exist in the default SMOKE files but the profile did exist.
- Create new temporal profiles and cross-references for SCCs in the MANE-VU inventory; neither the cross-reference nor profiles for the MANE-VU SCCs previously existed in the default SMOKE files.

a. Point Sources

A total of 30 point SCCs existed in the MANE-VU point source inventory that were not in the point source cross-reference file; therefore, the SCCs were added to the cross-reference file and assigned to existing profiles based on the assignment of similar SCCs already assigned to the profiles. Table II-2 lists the SCCs along with the state and county FIPS where they occurred in the MANE-VU inventory. Temporal profiles could not be identified for the SCCs listed in Table VII-3 due to either the SCC being shorter than 8-digits or the lack of information about the source categories for identifying an appropriate profile assignment. These SCCs were assigned the default profile by SMOKE.

b. Area Sources

For area sources, the improvements to the EPA cross-reference file included updates to existing profiles in the file based on MANE-VU-specific data (see Table VII-4), addition of SCCs that were assigned to existing profiles based on the assignment of similar SCCs already assigned to the profiles (see Table VII-5), and addition of new SCCs and profiles based on MANE-VU- or RPO-specific data (see Table VII-6).

Additional cross-referencing information used to revise the temporal cross-reference file included MANE-VU county-level information for residential wood combustion, monthly temporal profiles developed for NH_3 source categories using the Carnegie Mellon University (CMU) model, and a Delaware-specific cross-reference file associated with the Delaware inventory. The additions of new SCCs and new profiles shown in Table VII-6 mostly apply to the state of Delaware (State FIPS=10). For the FIPS column, the "-9" designation means the cross-reference is applied for all counties that do not have a county or state-specific SCC cross-reference record. These changes to the temporal cross-reference file allowed for the assignment of a non-flat temporal profile (262= uniform monthly, 7=uniform weekly and 24=uniform diurnal) to 95% of the SCCs in the area inventory.

2. Nonroad Sources

Nonroad sources used the same temporal profile and cross-reference files as area sources.

3. Onroad Sources

For onroad sources, the following States provided their own data to update the default temporal profile files and the temporal cross reference files: Connecticut, Delaware, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Vermont. Each of these States provided VMT information that could be used to develop monthly temporal profiles. The data were provided in a variety of formats, ranging from monthly or seasonal VMT to SMOKE-formatted monthly VMT temporal profiles. Where necessary, the monthly or seasonal VMT data were converted into the SMOKE monthly temporal profile format. In addition, New Jersey provided information for diurnal temporal profiles. However, the level of detail or variability provided in these monthly profiles varied by State. Connecticut's and Delaware's profiles each varied by county and road type. Maryland's profiles applied Statewide, with variability in the profiles by road type. Massachusetts' profiles varied by county, road type, and vehicle type. Both New Jersey and New York provided information for three monthly temporal profiles, each used throughout one of the three county groups in each State. The Pennsylvania profiles varied by county, but not by road type. Vermont provided information for a single monthly temporal profile to be used throughout the State.

B. Speciation Profiles

1. Point and Area Sources

The most recent SMOKE speciation cross-reference files available from EPA during the summer of 2004 were used as the starting point for developing the cross-reference files for point and area sources. These files were revised to complete SCC assignments for the Carbon Bond IV (CB-IV) with PM mechanism for point and area sources. In addition, sulfur tagging species were added to the REMSAD7 CB-IV with PM mechanism (see Table VII-1).

a. Point Sources

Thirty-one SCCs in the MANE-VU point source inventory did not have chemical speciation profile assignments for the CB-IV with PM mechanism in the default SMOKE chemical cross-reference file. For 10 of the SCCs, assignments for VOC and $PM_{2.5}$ were added to the speciation cross-reference file based on the speciation profile codes assigned to similar SCCs. Table VII-7 shows the SCCs where an SCC speciation cross-reference record was added, the VOC and $PM_{2.5}$ speciation profile code assigned, and the method used to assign the profiles. Assignments were not completed for the remaining 21 point source SCCs because of a lack of information on the emission sources needed to complete the assignments (see Table VII-8 for the list of the SCCs).

b. Area Sources

Speciation profile assignments were completed for many area source SCCs for the CB-IV with PM mechanism and were documented in separate spreadsheet files provided to MARAMA during September 2004. Assignments for VOC and $PM_{2.5}$ were added to the speciation cross-reference file based on the speciation profile codes assigned to similar SCCs. Note that the transport fractions for fugitive dust were applied as a part of the modeling effort to adjust the mass emissions in Version 3 of the inventory.

2. Nonroad Sources

No updates to the speciation profiles or speciation assignments for nonroad sources were provided by the MANE-VU States.

3. Onroad Sources

No updates to the speciation profiles or speciation assignments for onroad sources were provided by the MANE-VU States.

C. Spatial Allocation Profiles

The most recent spatial profile data files available from EPA during the summer of 2004 were used as the starting point for developing the spatial profile file for point and area sources. A detailed description of this surrogate dataset was provided in a file named "surrogate_ documentation_workbook052804.xls" from EPA's website at: http://www.epa.gov/ttn/ chief/emch/spatial/newsurrogate.html. Many SCCs in the MANE-VU inventory did not have surrogate assignments in the default SMOKE gridding cross-reference file. About 200 SCC assignments were added to the gridding cross-reference file. The assignments were based on matching surrogate descriptions from the EPA99 surrogate data with the SCC descriptions.

No updates to the spatial allocation files for nonroad and onroad sources were provided by the MANE-VU States.

D. Preparation of SMOKE (IDA) and RPO Data Exchange Protocol (NIF 3.0) Formats

Table VII-9 identifies the mass emissions and SMOKE input files for Version 3 of the MANE-VU point, area, nonroad, and onroad inventories.

The SMOKE input file format contains one field for storing daily emissions for each pollutant. The area source inventory contains summer day, winter day, and average day emissions depending on the state and source category. Thus, two sets of SMOKE input files were prepared for the area source inventory. One file contains annual, summer day, and average day emissions and the other file contains annual, winter day, and average day emissions. If summer day and average day emissions were provided for the same process and pollutant in the inventory, the summer day value was included in the SMOKE input file. If winter day and average day emissions were provided for the same process and pollutant in the inventory, the winter day value was included in the SMOKE input file.

The point source inventory contains summer day and winter day emissions. Two sets of SMOKE input files were prepared for point sources as well (one file containing annual and summer day emissions and the other containing annual and winter day emissions).

Table VII-10 provides the unique list of the start date, end date, and emission type combinations for daily emissions in the point and area source inventories that were used to define summer, winter, and average day emissions. This table also shows the names of the SMOKE input files in which the emissions are included.

For onroad sources, daily emissions were calculated by SMOKE using the monthly MOBILE6 input files included in the SMOKE input files.

The nonroad IDA file only has annual total emissions. The values in the "typical day" column are zero. Annual total emissions were allocated for each hour using the monthly, weekly, and diurnal profiles described in Section A.2 of this chapter.

Table VII-1. Profiles, Cross-references, and Documentation for Model Inputs for Version 3 of 2002 MANE-VU Inventory

Description	File Name	Format	Date of File used for Version 3	Size (Bytes)	Notes
SCC descriptions file	scc_desc_manevu.083104.txt	SMOKE	8/31/2004	1,335,524	
Temporal Allocation Profiles					
Technical memo on profile/cross-reference review for area sources	MANE-VU_AreaEI_review_draft_090304.doc	MS Word	9/3/2004	760,320	
Technical memo on profile/cross-reference review for point sources	MANE-VU_PointEI_review_draft_090304.doc	MS Word	9/3/2004	262,144	
Temporal profile cross-reference file for point sources	amptref.m3.manevu.vistascem.032805.txt	SMOKE	3/28/2005	704,998	Based on "amptref.m3.manevu.012405.txt" prepared for Version 1, but added VISTAS BaseD cross-references to the state-specific 2002 continuous emissions monitoring (CEM)-derived point source temporal profiles generated by VISTAS for their BaseD modeling.
Temporal profiles file for point sources	amptpro.m3.us+can.manevu.vistascem.032805.txt	SMOKE	3/28/2005	178,427	Based on "amptpro.m3.us+can.manevu.030205.txt" prepared for Version 1, but added state-specific 2002 CEM-derived point source temporal profiles generated by VISTAS for their BaseD modeling.
Temporal profile cross-reference file for area sources	amptref.m3.manevu.012405.txt	SMOKE	1/24/2005	687,196	
Temporal profiles file for area sources	amptpro.m3.us+can.manevu.030205.txt	SMOKE	3/2/2005	136,131	
Temporal cross-reference file containing state-specific onroad mobile source data for Connecticut, Delaware, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Vermont	MANEVU_2002_mtref_02022006_addCT.txt	SMOKE	2/22/2006	2,522,013	Data for Connecticut were added to the file after the file was prepared for the other states. Hence the reason “_addCT” is included at the end of the file name.

Table VII-1 (continued)

Description	File Name	Format	Date of File used for Version 3	Size (Bytes)	Notes
Temporal profiles file containing state-specific onroad mobile source data for Connecticut, Delaware, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Vermont	MANEVU_2002_mtpro_02022006_addCT.txt	SMOKE	2/22/2006	23,122	Data for Connecticut were added to the file after the file was prepared for the other states. Hence the reason "_addCT" is included at the end of the file name.
Spatial/Gridding					
Spreadsheet summary generated for area source gridding review	MANE-VU_agref_review.xls		8/31/2004	1,607,680	
Spatial profile cross-reference file	amgref.m3.us+can+mex.manevu.082404.txt	SMOKE	8/31/2004	89,860	
Gridding surrogate cross-reference file	amgref_us_051704_manevu_added	SMOKE	5/17/2004	35,825	Based on the surrogate cross-reference file downloaded from the EPA/CHIEF site that corresponds to the gridding surrogates file. However, several MANE-VU-specific additions included in "amgref.m3.us+can+mex.manevu.082404.txt" for Version 1 were added to the gridding-cross reference file downloaded from EPA. These are cross-references for SCCs 2806010000, 2806015000, 2870000011, 2870000015, 2870000021, and 2870000022.
Modeling grid (12-km)	amgpro.12km_041604.otc12.us.txt	SMOKE	4/16/2004	150,689,358	Based on downloaded 12-km EPA gridding surrogates windowed for the OTC domain
Speciation Profiles					
Spreadsheet summary generated for area source speciation review	MANE-VU_asref_review.xls	Excel	8/31/2004	5,626,880	
Speciation profiles file for CB-IV	gspro.cmaq.cb4p25.txt	SMOKE		142,255	
Speciation cross-reference file for CB-IV	gsref.cmaq.cb4p25.manevu.083104.txt	SMOKE	8/31/2004	786,998	

Table VII-1 (continued)

Description	File Name	Format	Date of File used for Version 3	Size (Bytes)	Notes
Speciation profile cross-reference assignment file	gsref.cmaq.cb4p25.txt	SMOKE	2/1/2005	754,302	This file is based on the file "gsref.cmaq.cb4p25.manevu.083104.txt" prepared for version 1 of the MANE-VU inventory. The only revision was to change the PM2_5 speciation profile # from its default 99999 to 35501 for some mobile source categories. This update had been done by either CENRAP or VISTAS in the speciation profiles they provided and the update had a more recent creation date than the MANE-VU files created for Version 1, so this appeared to be a refinement.
Speciation profiles for REMSAD7	gspro.remsad7.cb4mpm.txt_tag	SMOKE	5/1/2005	532,990	Based on "gspro.remsad7.cb4mpm.txt" in the SMOKE, but added tagged species for REMSAD state-level sulfur tagging.
Speciation cross-reference for REMSAD7	gsref.remsad7.cb4mpm.txt_tag	SMOKE	5/1/2005	2,614,360	Based on "gsref.remsad7.cb4mpm.txt" in the SMOKE, but added tagged species for REMSAD state-level sulfur tagging.
Transport fractions for fugitive dust	gcntl.xportfrac.txt	SMOKE	2/1/2004	124,495	File obtained from input file EPA used to adjust for PM transport for modeling of Clean Air Interstate Rule (CAIR).

Table VII-2. Point Source Temporal Cross-reference Additions

State	FIPS	SCC	Recommended profiles			Method of assignment	SCC Description (Complete description not always available)
			Monthly	Weekly	Diurnal		
VT	50005	10200908	262	7	24	Use SCC=102009XX profiles	External Combustion Boilers;Industrial;Wood/Bark Waste;Wood-fired Boiler - Dry Wood (<20% moisture)
VT	50019	10200908	262	7	24	Use SCC=102009XX profiles	External Combustion Boilers;Industrial;Wood/Bark Waste;Wood-fired Boiler - Dry Wood (<20% moisture)
VT	50021	10200908	262	7	24	Use SCC=102009XX profiles	External Combustion Boilers;Industrial;Wood/Bark Waste;Wood-fired Boiler - Dry Wood (<20% moisture)
VT	50017	10300908	262	7	24	Use SCC=103009XX profiles	External Combustion Boilers;Commercial/Institutional;Wood/Bark Waste;Wood-fired Boiler - Dry Wood (<20% moisture)
PA	42009	20200299	262	7	24	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42029	20200299	262	7	24	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42045	20200299	262	7	24	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42061	20200299	262	7	24	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42067	20200299	262	7	24	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42015	20300299	262	7	24	Use SCC=203002XX profiles	Internal Combustion Engines;Commercial/Institutional;Natural Gas;Unknown
PA	42029	20300299	262	7	24	Use SCC=203002XX profiles	Internal Combustion Engines;Commercial/Institutional;Natural Gas;Unknown
PA	42037	20300299	262	7	24	Use SCC=203002XX profiles	Internal Combustion Engines;Commercial/Institutional;Natural Gas;Unknown
PA	42071	20300299	262	7	24	Use SCC=203002XX profiles	Internal Combustion Engines;Commercial/Institutional;Natural Gas;Unknown
PA	42011	28888899	262	7	24	Use SCC=288888XX profiles	Internal Combustion Engines;Fugitive Emissions;Other Not Classified;Specify in Comments
PA	42123	28888899	262	7	24	Use SCC=288888XX profiles	Internal Combustion Engines;Fugitive Emissions;Other Not Classified;Specify in Comments
PA	42123	28888899	262	7	24	Use SCC=288888XX profiles	Internal Combustion Engines;Fugitive Emissions;Other Not Classified;Specify in Comments
PA	42129	28888899	262	7	24	Use SCC=288888XX profiles	Internal Combustion Engines;Fugitive Emissions;Other Not Classified;Specify in Comments
MD	24031	30500261	262	7	24	Use SCC=30500260 profile	Industrial Processes;Mineral Products;Asphalt Concrete;Drum Mix Plant: Rotary Drum Dryer/Mixer, Waste/Drain/#6 Oil-Fired

Table VII-2 (continued)

State	FIPS	SCC	Recommended profiles			Method of assignment	SCC Description (Complete description not always available)
			Monthly	Weekly	Diurnal		
NY	36055	31603001	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Substrate Preparation;Extrusion Operations
NY	36055	31603002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Substrate Preparation;Film Support Operations
NY	36055	31604001	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Chemical Preparation;Chemical Manufacturing
NY	36055	31604002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Chemical Preparation;Emulsion Making Operations
NY	36055	31604003	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Chemical Preparation;Chemical Mixing Operations
NY	36055	31605001	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Surface Treatments;Surface Coating Operations
NY	36055	31605002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Surface Treatments;Grid Ionizers
NY	36055	31605003	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Surface Treatments;Corona Discharge Treatment
NY	36055	31606001	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Finishing Operations;General Film Manufacturing
NY	36055	31606002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Finishing Operations;Cutting/Slitting Operations
PA	42101	31606002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Finishing Operations;Cutting/Slitting Operations
NY	36055	31612001	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Cleaning Operations;Tank Cleaning Operations
NY	36055	31612002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Cleaning Operations;General Cleaning Operations
NY	36055	31613002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Storage Operations;General Storage Operations

Table VII-2 (continued)

State	FIPS	SCC	Recommended profiles			Method of assignment	SCC Description (Complete description not always available)
			Monthly	Weekly	Diurnal		
NY	36055	31614001	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Material Transfer Operations;Filling Operations (non petroleum)
NY	36055	31614002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Material Transfer Operations;Transfer of Chemicals
NY	36055	31615001	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Separation Processes;Recovery Operations
NY	36055	31615003	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Separation Processes;Distillation Operations
NY	36055	31616002	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Other Operations;General Process Tank Operations
NY	36055	31616003	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Other Operations;Miscellaneous Manufacturing Operations
NY	36055	31616004	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Other Operations;Paint Spraying Operations
NY	36055	31616006	262	7	24	Use SIC=3861 and SIC=2796 as guidance and evaluate specific sources	Industrial Processes;Photographic Film Manufacturing;Support Activities - Other Operations;Chemical Weighing Operations
PA	Numerous counties	39000698	262	7	24	Use SCC=39000699 profile	Industrial Processes;In-process Fuel Use;Natural Gas;Unknown
NJ	Numerous counties	39999901	262	7	24	Use SCC=399999XX profiles	Industrial Processes;Miscellaneous Manufacturing Industries;Miscellaneous Industrial Processes;Unknown
PA	42015	40202598	266	7	16	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42017	40202598	266	7	16	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42091	40202598	266	7	16	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42095	40202598	266	7	16	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42097	40202598	266	7	16	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42013	40400299	262	7	24	Use SCC=404002XX profiles	Petroleum and Solvent Evaporation;Petroleum Liquids Storage (non-Refinery);Bulk Plants;Unknown
PA	42041	40400299	262	7	24	Use SCC=404002XX profiles	Petroleum and Solvent Evaporation;Petroleum Liquids Storage (non-Refinery);Bulk Plants;Unknown

Table VII-2 (continued)

State	FIPS	SCC	Recommended profiles			Method of assignment	SCC Description (Complete description not always available)
			Monthly	Weekly	Diurnal		
PA	42045	40400299	262	7	24	Use SCC=404002XX profiles	Petroleum and Solvent Evaporation;Petroleum Liquids Storage (non-Refinery);Bulk Plants;Unknown
PA	42071	40400299	262	7	24	Use SCC=404002XX profiles	Petroleum and Solvent Evaporation;Petroleum Liquids Storage (non-Refinery);Bulk Plants;Unknown

Table VII-3. Unknown SCCs in the MANE-VU Point Source Inventory

State	FIPS	SCC	Description
PA	42101	24950002	Need more info: Unknown SCC
PA	42061	40500299	Need more info:Printing/Publishing; General
PA	42091	40500299	Need more info:Printing/Publishing; General
PA	42133	40500299	Need more info:Printing/Publishing; General

Table VII-4. Area Source Temporal Cross-Reference Updates

SCC	SCC description	SMOKE Default profile			New MANE-VU profile		
		Monthly	Weekly	Diurnal	Monthly	Weekly	Diurnal
30502713	Industrial Processes;Mineral Products;Industrial Sand and Gravel;Screening: Size Classification	262	7	24	262	5	12
30502760	Industrial Processes;Mineral Products;Industrial Sand and Gravel;Sand Handling, Transfer, and Storage	262	7	24	262	5	12
2302000000	Industrial Processes;Food and Kindred Products: SIC 20;All Processes;Total	262	7	26	262	7	250
2302050000	Industrial Processes;Food and Kindred Products: SIC 20;Bakery Products;Total	262	7	26	262	5	26
2305000000	Industrial Processes;Mineral Processes: SIC 32;All Processes;Total	262	7	26	262	5	10
2309100010	Industrial Processes;Fabricated Metals: SIC 34;Coating, Engraving, and Allied Services;Electroplating	262	7	26	262	5	10
2311010000	Industrial Processes;Construction: SIC 15 - 17;General Building Construction;Total	262	7	26	262	5	12
2311020000	Industrial Processes;Construction: SIC 15 - 17;Heavy Construction;Total	262	7	26	262	5	12
2311030000	Industrial Processes;Construction: SIC 15 - 17;Road Construction;Total	262	7	26	262	5	12
2325000000	Industrial Processes;Mining and Quarrying: SIC 14;All Processes;Total	262	7	26	262	5	10
2399000000	Industrial Processes;Industrial Processes: NEC;Industrial Processes: NEC;Total	262	7	26	262	5	10
2399010000	Industrial Processes; Industrial Refrigeration; Refrigerant Losses; All Processes	262	7	26	262	5	10
2401015000	Solvent Utilization;Surface Coating;Factory Finished Wood: SIC 2426 thru 242;Total: All Solvent Types	173	7	26	173	5	26
2401020000	Solvent Utilization;Surface Coating;Wood Furniture: SIC 25;Total: All Solvent Types	287	7	26	287	5	26
2401025000	Solvent Utilization;Surface Coating;Metal Furniture: SIC 25;Total: All Solvent Types	287	7	26	287	5	26
2401030000	Solvent Utilization;Surface Coating;Paper: SIC 26;Total: All Solvent Types	257	7	26	257	5	26
2401040000	Solvent Utilization;Surface Coating;Metal Cans: SIC 341;Total: All Solvent Types	253	7	26	253	5	26
2401045000	Solvent Utilization;Surface Coating;Metal Coils: SIC 3498;Total: All Solvent Types	253	7	26	253	5	26
2401050000	Solvent Utilization;Surface Coating;Miscellaneous Finished Metals: SIC 34 - (341 + 3498);Total: All Solvent Types	253	7	26	253	5	26

Table VII-4 (continued)

SCC	SCC description	SMOKE Default profile			New MANE-VU profile		
		Monthly	Weekly	Diurnal	Monthly	Weekly	Diurnal
2401055000	Solvent Utilization;Surface Coating;Machinery and Equipment: SIC 35;Total: All Solvent Types	253	7	26	253	5	26
2401060000	Solvent Utilization;Surface Coating;Large Appliances: SIC 363;Total: All Solvent Types	262	7	26	262	5	26
2401065000	Solvent Utilization;Surface Coating;Electronic and Other Electrical: SIC 36 - 363;Total: All Solvent Types	253	7	26	253	5	26
2401070000	Solvent Utilization;Surface Coating;Motor Vehicles: SIC 371;Total: All Solvent Types	140	7	26	140	5	26
2401075000	Solvent Utilization;Surface Coating;Aircraft: SIC 372;Total: All Solvent Types	169	7	26	169	5	26
2401080000	Solvent Utilization;Surface Coating;Marine: SIC 373;Total: All Solvent Types	266	7	26	266	5	26
2401085000	Solvent Utilization;Surface Coating;Railroad: SIC 374;Total: All Solvent Types	169	7	26	169	5	26
2401090000	Solvent Utilization;Surface Coating;Miscellaneous Manufacturing;Total: All Solvent Types	260	7	26	260	5	26
2401090999	Solvent Utilization;Surface Coating;Miscellaneous Manufacturing;Solvents: NEC	260	7	26	260	5	26
2401200000	Solvent Utilization;Surface Coating;Other Special Purpose Coatings;Total: All Solvent Types	260	7	26	260	5	26
2401990000	Solvent Utilization;Surface Coating;All Surface Coating Categories;Total: All Solvent Types	260	7	26	260	5	26
2401990999	Solvent Utilization;Surface Coating;All Surface Coating Categories;Solvents: NEC	260	7	26	260	5	26
2415000000	Solvent Utilization;Degreasing;All Processes/All Industries;Total: All Solvent Types	253	7	26	253	5	26
2415020000	Solvent Utilization;Degreasing;Fabricated Metal Products (SIC 34): All Processes;Total: All Solvent Types	253	7	26	253	5	12
2415025000	Solvent Utilization;Degreasing;Industrial Machinery and Equipment (SIC 35): All Processes;Total: All Solvent Types	253	7	26	253	5	12
2415030000	Solvent Utilization;Degreasing;Electronic and Other Elec. (SIC 36): All Processes;Total: All Solvent Types	253	7	26	253	5	12
2415035000	Solvent Utilization;Degreasing;Transportation Equipment (SIC 37): All Processes;Total: All Solvent Types	253	7	26	253	5	12
2415045000	Solvent Utilization;Degreasing;Miscellaneous Manufacturing (SIC 39): All Processes;Total: All Solvent Types	253	7	26	253	5	12
2415055000	Solvent Utilization;Degreasing;Automotive Dealers (SIC 55): All Processes;Total: All Solvent Types	253	7	26	253	5	12
2415060000	Solvent Utilization;Degreasing;Miscellaneous Repair Services (SIC 76): All Processes;Total: All Solvent Types	253	7	26	253	5	12

Table VII-4 (continued)

SCC	SCC description	SMOKE Default profile			New MANE-VU profile		
		Monthly	Weekly	Diurnal	Monthly	Weekly	Diurnal
2415065000	Solvent Utilization;Degreasing;Auto Repair Services (SIC 75): All Processes;Total: All Solvent Types	253	7	26	253	6	12
2415100000	Solvent Utilization;Degreasing;All Industries: Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415105000	Solvent Utilization;Degreasing;Furniture and Fixtures (SIC 25): Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415110000	Solvent Utilization;Degreasing;Primary Metal Industries (SIC 33): Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415120000	Solvent Utilization;Degreasing;Fabricated Metal Products (SIC 34): Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415125000	Solvent Utilization;Degreasing;Industrial Machinery and Equipment (SIC 35): Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415130000	Solvent Utilization;Degreasing;Electronic and Other Elec. (SIC 36): Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415135000	Solvent Utilization;Degreasing;Transportation Equipment (SIC 37): Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415140000	Solvent Utilization;Degreasing;Instruments and Related Products (SIC 38): Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415145000	Solvent Utilization;Degreasing;Miscellaneous Manufacturing (SIC 39): Open Top Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415200000	Solvent Utilization;Degreasing;All Industries: Conveyerized Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415230000	Solvent Utilization;Degreasing;Electronic and Other Elec. (SIC 36): Conveyerized Degreasing;Total: All Solvent Types	253	7	26	253	5	12
2415300000	Solvent Utilization;Degreasing;All Industries: Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415305000	Solvent Utilization;Degreasing;Furniture and Fixtures (SIC 25): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415310000	Solvent Utilization;Degreasing;Primary Metal Industries (SIC 33): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415320000	Solvent Utilization;Degreasing;Fabricated Metal Products (SIC 34): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415325000	Solvent Utilization;Degreasing;Industrial Machinery and Equipment (SIC 35): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415330000	Solvent Utilization;Degreasing;Electronic and Other Elec. (SIC 36): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12

Table VII-4 (continued)

SCC	SCC description	SMOKE Default profile			New MANE-VU profile		
		Monthly	Weekly	Diurnal	Monthly	Weekly	Diurnal
2415335000	Solvent Utilization;Degreasing;Transportation Equipment (SIC 37): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415340000	Solvent Utilization;Degreasing;Instruments and Related Products (SIC 38): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415345000	Solvent Utilization;Degreasing;Miscellaneous Manufacturing (SIC 39): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415355000	Solvent Utilization;Degreasing;Automotive Dealers (SIC 55): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2415360000	Solvent Utilization;Degreasing;Auto Repair Services (SIC 75): Cold Cleaning;Total: All Solvent Types	253	7	26	253	6	12
2415365000	Solvent Utilization;Degreasing;Miscellaneous Repair Services (SIC 76): Cold Cleaning;Total: All Solvent Types	253	7	26	253	5	12
2425000000	Solvent Utilization;Graphic Arts;All Processes;Total: All Solvent Types	257	7	26	257	5	26
2425010000	Solvent Utilization;Graphic Arts;Lithography;Total: All Solvent Types	257	7	26	257	5	26
2425020000	Solvent Utilization;Graphic Arts;Letterpress;Total: All Solvent Types	257	7	26	257	5	26
2425030000	Solvent Utilization;Graphic Arts;Rotogravure;Total: All Solvent Types	262	7	26	262	5	26
2425040000	Solvent Utilization;Graphic Arts;Flexography;Total: All Solvent Types	257	7	26	257	5	26
2430000000	Solvent Utilization;Rubber/Plastics;All Processes;Total: All Solvent Types	200	7	26	200	5	26
2601010000	Waste Disposal, Treatment, and Recovery;On-site Incineration;Industrial;Total	262	7	26	262	5	12
2601020000	Waste Disposal, Treatment, and Recovery;On-site Incineration;Commercial/Institutional;Total	262	7	26	262	5	12
2610010000	Waste Disposal, Treatment, and Recovery;Open Burning;Industrial;Total	262	7	26	262	5	12
2610020000	Waste Disposal, Treatment, and Recovery;Open Burning;Commercial/Institutional;Total	262	7	26	262	5	12
2805020000	Miscellaneous Area Sources;Agriculture Production - Livestock;Cattle and Calves Waste Emissions;Total	489	7	26	1500	7	26
2805025000	Miscellaneous Area Sources;Agriculture Production - Livestock;Hogs and Pigs Waste Emissions;Total	489	7	26	1500	7	26
2805030000	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry Waste Emissions;Total	489	7	26	1500	7	26

Table VII-4 (continued)

SCC	SCC description	SMOKE Default profile			New MANE-VU profile		
		Monthly	Weekly	Diurnal	Monthly	Weekly	Diurnal
2805035000	Miscellaneous Area Sources;Agriculture Production - Livestock;Horses and Ponies Waste Emissions;Total	262	7	26	1500	7	26
2805040000	Miscellaneous Area Sources;Agriculture Production - Livestock;Sheep and Lambs Waste Emissions;Total	489	7	26	1500	7	26
2805045001	Miscellaneous Area Sources;Agriculture Production - Livestock;Goats Waste Emissions;Total	489	7	26	262	7	24
2810015000	Miscellaneous Area Sources;Other Combustion;Prescribed Burning for Forest Management;Total	14	7	24	3	11	13

Table VII-5. Area Source Temporal Cross-Reference Additions

SCC	Description	Month	Week	Diurnal
2104008002	Stationary Source Fuel Combustion;Residential;Wood;Fireplaces: Insert; non-EPA certified	485	7	26
2104008003	Stationary Source Fuel Combustion;Residential;Wood;Fireplaces: Insert; EPA certified; non-catalytic	485	7	26
2104008004	Stationary Source Fuel Combustion;Residential;Wood;Fireplaces: Insert; EPA certified; catalytic	485	7	26
2302002100	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Charbroiling;Conveyorized Charbroiling	262	7	26
2302002200	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Charbroiling;Under-fired Charbroiling	262	7	26
2302003000	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Total	262	7	26
2302003100	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Flat Griddle Frying	262	7	26
2302003200	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Clamshell Griddle Frying	262	7	26
2302080002	Industrial Processes;Food and Kindred Products: SIC 20;Miscellaneous Food and Kindred Products;Refrigeration	262	7	26
2401002000	Solvent Utilization;Surface Coating;Architectural Coatings - Solvent-based;Total: All Solvent Types	467	7	26
2401003000	Solvent Utilization;Surface Coating;Architectural Coatings - Water-based;Total: All Solvent Types	467	7	26
2401102000	Solvent Utilization;Surface Coating;Industrial Maintenance Coatings-Solvent-based;Total: All Solvent Types	500	5	26
2401103000	Solvent Utilization;Surface Coating;Industrial Maintenance Coatings-Water-based;Total: All Solvent Types	500	5	26
2415270000	Solvent Utilization;Degreasing;All Manufacturing (except SIC 36): Vapor and In-Line Cleaning;Total: All Solvent Types	253	5	12
2415280000	Solvent Utilization;Degreasing;Electronic and Other Elec. (SIC 36): Vapor and In-Line Cleaning;Total: All Solvent Types	253	5	12
2415370000	Solvent Utilization;Degreasing;Transportation Equipment Repair Services: Cold Cleaning;Total: All Solvent Types	253	5	12
2415380000	Solvent Utilization;Degreasing;All Manufacturing: Cold Cleaning;Total: All Solvent Types	253	5	12
2610000400	Waste Disposal, Treatment, and Recovery;Open Burning;All Categories;Yard Waste - Brush Species Unspecified	262	7	26
2610000500	Waste Disposal, Treatment, and Recovery;Open Burning;All Categories;Land Clearing Debris (use 28-10-005-000 for Logging Debris Burning)	262	7	26
2610040400	Waste Disposal, Treatment, and Recovery;Open Burning;Municipal (collected from residences, parks,other for central burn);Yard Waste - Total	262	7	26
2630020010	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Wastewater Treatment Processes Total	262	7	24

Table VII-5 (continued)

SCC	Description	Month	Week	Diurnal
2630020020	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Biosolids Processes Total	262	7	24
2630020030	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Land Application - Digested Sludge	262	7	24
2630050000	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Land Application - Digested Sludge	262	7	24
2680001000	Waste Disposal, Treatment, and Recovery;Composting;100% Biosolids (e.g., sewage sludge, manure, mixtures of these matls);All Processes	262	7	26
2680002000	Waste Disposal, Treatment, and Recovery;Composting;Mixed Waste (e.g., a 50:50 mixture of biosolids and green wastes);All Processes	262	7	26
2801700011	Miscellaneous Area Sources;Agriculture Production - Crops;Fertilizer Application;Calcium Ammonium Nitrate	998	7	26
2801700012	Miscellaneous Area Sources;Agriculture Production - Crops;Fertilizer Application;Potassium Nitrate	998	7	26
2801700013	Miscellaneous Area Sources;Agriculture Production - Crops;Fertilizer Application;Diammonium Phosphate	998	7	26
2801700014	Miscellaneous Area Sources;Agriculture Production - Crops;Fertilizer Application;Monoammonium Phosphate	998	7	26
2801700015	Miscellaneous Area Sources;Agriculture Production - Crops;Fertilizer Application;Liquid Ammonium Polyphosphate	998	7	26
2801700099	Miscellaneous Area Sources;Agriculture Production - Crops;Fertilizer Application;Miscellaneous Fertilizers	998	7	26
2805001100	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef cattle - finishing operations on feedlots (drylots);Confinement	1500	7	26
2805001200	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef cattle - finishing operations on feedlots (drylots);Manure handling and storage	1500	7	26
2805001300	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef cattle - finishing operations on feedlots (drylots);Land application of manure	1500	7	26
2805002000	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef Cattle Composite; Not Elsewhere Classified	1500	7	26
2805003100	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef cattle - finishing operations on pasture/range;Confinement	1500	7	26
2805007100	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with dry manure management systems;Confinement	1500	7	26
2805007200	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - layers with dry manure management systems;Management	1500	7	26
2805007300	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with dry manure management systems;Land application of manure	262	7	24
2805007330	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - layers with dry manure management systems; Land application	1500	7	26
2805007340	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - layers with dry manure management systems; Land application	1500	7	26

Table VII-5 (continued)

SCC	Description	Month	Week	Diurnal
2805008100	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with wet manure management systems;Confinement	1500	7	26
2805008200	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with wet manure management systems;Manure handling and storage	1500	7	26
2805008300	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with wet manure management systems;Land application of manure	1500	7	26
2805009100	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - broilers;Confinement	1500	7	26
2805009300	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - broilers;Land application of manure	1500	7	26
2805010100	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - turkeys;Confinement	262	7	24
2805010200	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - turkeys;Manure handling and storage	262	7	24
2805010300	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - turkeys;Land application of manure	1500	7	26
2805018000	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle composite; Not Elsewhere Classified	1501	7	26
2805019100	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - flush dairy;Confinement	1500	7	26
2805019200	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - flush dairy;Manure handling and storage	1500	7	26
2805019300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - flush dairy;Land application of manure	1500	7	26
2805020001	Miscellaneous Area Sources;Agriculture Production - Livestock;Cattle and Calves Waste Emissions;Milk Cows	1500	7	26
2805020002	Miscellaneous Area Sources;Agriculture Production - Livestock;Cattle and Calves Waste Emissions;Beef Cows	1500	7	26
2805020003	Miscellaneous Area Sources;Agriculture Production - Livestock;Cattle and Calves Waste Emissions;Heifers and Heifer Calves	1500	7	26
2805021300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - scrape dairy;Land application of manure	1500	7	26
2805022100	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - deep pit dairy;Confinement	1500	7	26
2805022200	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - deep pit dairy;Manure handling and storage	1500	7	26
2805022300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - deep pit dairy;Land application of manure	1500	7	26
2805023300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - drylot/pasture dairy;Land application of manure	1500	7	26
2805030001	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry Waste Emissions;Pullet Chicks and Pullets less than 13 weeks old	1500	7	26

Table VII-5 (continued)

SCC	Description	Month	Week	Diurnal
2805030002	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry Waste Emissions;Pullets 13 weeks old and older but less than 20 weeks	1500	7	26
2805030003	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry Waste Emissions;Layers	1500	7	26
2805030004	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry Waste Emissions;Broilers	1500	7	26
2805030008	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry Waste Emissions;Geese	1500	7	26
2805039100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - operations with lagoons;Confinement	1500	7	26
2805039200	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - operations with lagoons;Manure handling and storage	1500	7	26
2805039300	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - operations with lagoons;Land application of manure	1500	7	26
2805045000	Miscellaneous Area Sources;Agriculture Production - Livestock;Goats Waste Emissions;Not Elsewhere Classified	1500	7	26
2805045002	Miscellaneous Area Sources;Agriculture Production - Livestock;Goats Waste Emissions;Angora Goats	1500	7	26
2805045003	Miscellaneous Area Sources;Agriculture Production - Livestock;Goats Waste Emissions;Milk Goats	1500	7	26
2805047100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - deep-pit house operations;Confinement	1500	7	26
2805047300	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - deep-pit house operations;Land application of manure	1500	7	26
2805053100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - outdoor operations; Confinement	1500	7	26
2805054000	Miscellaneous Area Sources;Agricultural Production - Livestock;"Mules; Donkeys; and Burros Waste Emissions";Not Elsewhere Classified	262	7	24
2806010000	Miscellaneous Area Sources;Domestic Animals Waste Emissions;Cats;Total	262	7	24
2806015000	Miscellaneous Area Sources;Domestic Animals Waste Emissions;Dogs;Total	262	7	24
2807020001	Miscellaneous Area Sources;Wild Animals Waste Emissions;Bears;Black Bears	262	7	26
2807020002	Miscellaneous Area Sources;Wild Animals Waste Emissions;Bears;Grizzly Bears	262	7	26
2807025000	Miscellaneous Area Sources;Wild Animals Waste Emissions;Elk;Total	262	7	26
2807030000	Miscellaneous Area Sources;Wild Animals Waste Emissions;Deer;Total	262	7	26
2807040000	Miscellaneous Area Sources;Wild Animals Waste Emissions;Birds;Total	262	7	26
2810060100	Miscellaneous Area Sources;Other Combustion;Cremation;Humans	262	7	24
2870000001	Miscellaneous Area Sources;Humans;Respiration and Perspiration;Total	262	7	24
2870000002	Miscellaneous Area Sources;Humans;Infant Diapered Waste;Total	262	7	24
2870000011	Miscellaneous Area Sources;Domestic Activity;Household Products;Total	262	7	24

Table VII-5 (continued)

SCC	Description	Month	Week	Diurnal
2870000015	Miscellaneous Area Sources;Domestic Activity;Non-agricultural Fertilizers;Total	3	7	24
2870000021	Miscellaneous Area Sources;Domestic Animals;Dogs;Total	262	7	24
2870000022	Miscellaneous Area Sources;Domestic Animals;Cats;Total	262	7	24
2870000031	Miscellaneous Area Sources;Wild Animals;Deer;Total	262	7	24

Table VII-6. Area Source Temporal Cross-Reference and Profile Additions for the MANE-VU Inventory

SCC	Description	Month	Week	Diurnal	FIPS
2102002000	Stationary Source Fuel Combustion;Industrial;Bituminous/Subbituminous Coal;Total: All Boiler Types	1726	8	26	10000
2102006000	Stationary Source Fuel Combustion;Industrial;Natural Gas;Total: Boilers and IC Engines	1727	8	26	10000
2102007000	Stationary Source Fuel Combustion;Industrial;Liquified Petroleum Gas (LPG);Total: All Boiler Types	1727	8	26	10000
2103001000	Stationary Source Fuel Combustion;Commercial/Institutional;Anthracite Coal;Total: All Boiler Types	1720	8	26	10000
2103004000	Stationary Source Fuel Combustion;Commercial/Institutional;Distillate Oil;Total: Boilers and IC Engines	1721	8	26	10000
2103006000	Stationary Source Fuel Combustion;Commercial/Institutional;Natural Gas;Total: Boilers and IC Engines	1722	8	26	10000
2103007000	Stationary Source Fuel Combustion;Commercial/Institutional;Liquified Petroleum Gas (LPG);Total: All Combustor Types	1723	8	26	10000
2104002000	Stationary Source Fuel Combustion;Residential;Bituminous/Subbituminous Coal;Total: All Combustor Types	1732	7	26	10000
2104004000	Stationary Source Fuel Combustion;Residential;Distillate Oil;Total: All Combustor Types	1733	7	26	10000
2104006000	Stationary Source Fuel Combustion;Residential;Natural Gas;Total: All Combustor Types	1734	7	26	10000
2104007000	Stationary Source Fuel Combustion;Residential;Liquified Petroleum Gas (LPG);Total: All Combustor Types	1735	7	26	10000
2104008000	Stationary Source Fuel Combustion;Residential;Wood;Total: Woodstoves and Fireplaces	1740	2007	2014	10001
2104008000	Stationary Source Fuel Combustion;Residential;Wood;Total: Woodstoves and Fireplaces	1741	2008	2015	10003
2104008000	Stationary Source Fuel Combustion;Residential;Wood;Total: Woodstoves and Fireplaces	1742	2009	2016	10005
2104008000	Stationary Source Fuel Combustion;Residential;Wood;Total: Woodstoves and Fireplaces	1742	2009	2016	10005
2104008070	Stationary Source Fuel Combustion;Residential;Wood;Outdoor Wood Burning Equipment;	1743	2010	2017	10001
2104008070	Stationary Source Fuel Combustion;Residential;Wood;Outdoor Wood Burning Equipment;	1744	2011	2017	10003
2104008070	Stationary Source Fuel Combustion;Residential;Wood;Outdoor Wood Burning Equipment;	1745	2012	2017	10005
2104011000	Stationary Source Fuel Combustion;Residential;Kerosene;Total: All Heater Types	1736	7	26	10000
2294000000	Mobile Sources;Paved Roads;All Paved Roads;Total: Fugitives	1729	7	26	10000
2302002100	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Charbroiling;Conveyorized Charbroiling	262	7	26	10000
2302002100	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Charbroiling;Conveyorized Charbroiling	262	7	26	10000
2302002200	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Charbroiling;Under-fired Charbroiling	262	7	26	10000

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2302002200	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Charbroiling;Under-fired Charbroiling	262	7	26	10000
2302003000	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Total	262	7	26	10000
2302003000	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Total	262	7	26	10000
2302003100	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Flat Griddle Frying	262	7	26	10000
2302003100	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Flat Griddle Frying	262	7	26	10000
2302003200	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Clamshell Griddle Frying	262	7	26	10000
2302003200	Industrial Processes;Food and Kindred Products: SIC 20;Commercial Deep Fat Frying;Clamshell Griddle Frying	262	7	26	10000
2311030000	Industrial Processes;Construction: SIC 15 - 17;Road Construction;Total	262	7	9	10000
2401002000	Solvent Utilization;Surface Coating;Architectural Coatings - Solvent-based;Total: All Solvent Types	467	7	26	-9
2401002000	Solvent Utilization;Surface Coating;Architectural Coatings - Solvent-based;Total: All Solvent Types	500	20	27	10000
2401003000	Solvent Utilization;Surface Coating;Architectural Coatings - Water-based;Total: All Solvent Types	467	7	26	-9
2401003000	Solvent Utilization;Surface Coating;Architectural Coatings - Water-based;Total: All Solvent Types	500	20	27	10000
2401005000	Solvent Utilization;Surface Coating;Auto Refinishing: SIC 7532;Total: All Solvent Types	1702	5	27	10000
2401005500	Solvent Utilization;Surface Coating;Auto Refinishing: SIC 7532;Surface Preparation Solvents	1702	5	27	10000
2401005600	Solvent Utilization;Surface Coating;Auto Refinishing: SIC 7532;Primers	1702	5	27	10000
2401005700	Solvent Utilization;Surface Coating;Auto Refinishing: SIC 7532;Top Coats	1702	5	27	10000
2401005800	Solvent Utilization;Surface Coating;Auto Refinishing: SIC 7532;Clean-up Solvents	1702	5	27	10000
2401005800	Solvent Utilization;Surface Coating;Auto Refinishing: SIC 7532;Clean-up Solvents	1702	5	27	10001
2401008000	Solvent Utilization;Surface Coating;Traffic Markings;Total: All Solvent Types	1700	7	26	-9
2401008000	Solvent Utilization;Surface Coating;Traffic Markings;Total: All Solvent Types	1700	5	26	10000
2401008999	Solvent Utilization;Surface Coating;Traffic Markings;Solvents: NEC	1700	7	26	-9
2401102000	Solvent Utilization;Surface Coating;Industrial Maintenance Coatings-Solvent-based;Total: All Solvent Types	500	5	26	10000
2401103000	Solvent Utilization;Surface Coating;Industrial Maintenance Coatings-Water-based;Total: All Solvent Types	500	5	26	10000
2415100000	Solvent Utilization;Degreasing;All Industries: Open Top Degreasing;Total: All Solvent Types	262	6	5	10000
2415130000	Solvent Utilization;Degreasing;Electronic and Other Elec. (SIC 36): Open Top Degreasing;Total: All Solvent Types	262	6	5	10000
2415300000	Solvent Utilization;Degreasing;All Industries: Cold Cleaning;Total: All Solvent Types	262	6	5	10000
2415360000	Solvent Utilization;Degreasing;Auto Repair Services (SIC 75): Cold Cleaning;Total: All Solvent Types	262	5	5	10000
2461021000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Cutback Asphalt;Total: All Solvent Types	1712	7	26	10001
2461021000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Cutback Asphalt;Total: All Solvent Types	1714	7	26	10001
2461021000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Cutback Asphalt;Total: All Solvent Types	1713	7	26	10003

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2461021000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Cutback Asphalt;Total: All Solvent Types	1712	7	26	10003
2461021000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Cutback Asphalt;Total: All Solvent Types	1714	7	26	10005
2461021000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Cutback Asphalt;Total: All Solvent Types	1713	7	26	10005
2461022000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Emulsified Asphalt;Total: All Solvent Types	1709	7	26	10001
2461022000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Emulsified Asphalt;Total: All Solvent Types	1711	7	26	10001
2461022000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Emulsified Asphalt;Total: All Solvent Types	1710	7	26	10003
2461022000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Emulsified Asphalt;Total: All Solvent Types	1709	7	26	10003
2461022000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Emulsified Asphalt;Total: All Solvent Types	1711	7	26	10005
2461022000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Emulsified Asphalt;Total: All Solvent Types	1710	7	26	10005
2461850001	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Pesticide Application: Agricultural;Herbicides, Corn	536	7	26	10000
2461850005	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Pesticide Application: Agricultural;Herbicides, Soy Beans	536	7	26	10000
2461850006	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Pesticide Application: Agricultural;Herbicides, Hay & Grains	536	7	26	10000
2461850051	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Pesticide Application: Agricultural;Other Pesticides, Corn	536	7	26	10000
2461850055	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Pesticide Application: Agricultural;Other Pesticides, Soy Beans	536	7	26	10000
2461850056	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Pesticide Application: Agricultural;Other Pesticides, Hay & Grains	536	7	26	10000
2501011010	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Vapor Losses	1701	7	26	10000
2501011010	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Vapor Losses	1701	7	26	10000
2501011011	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Permeation	1701	7	26	10000
2501011011	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Permeation	1701	7	26	10000
2501011012	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Diurnal	1701	7	26	10000
2501011012	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Diurnal	1701	7	26	10000
2501011015	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Spillage	1701	7	26	10000
2501011015	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Spillage	1701	7	26	10000
2501011016	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Transport	1701	7	26	10000
2501011016	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Residential;Transport	1701	7	26	10000
2501012010	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Vapor Losses	1701	7	26	10000
2501012010	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Vapor Losses	1701	7	26	10000

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2501012011	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Permeation	1701	7	26	10000
2501012011	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Permeation	1701	7	26	10000
2501012012	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Diurnal	1701	7	26	10000
2501012012	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Diurnal	1701	7	26	10000
2501012015	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Spillage	1701	7	26	10000
2501012015	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Spillage	1701	7	26	10000
2501012016	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Transport	1701	7	26	10000
2501012016	Storage and Transport;Petroleum and Petroleum Product Storage;Portable Containers: Commercial;Transport	1701	7	26	10000
2501060000	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Total: All Gasoline/All Processes	1701	7	26	-9
2501060050	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 1: Total	1701	7	26	-9
2501060051	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 1: Submerged Filling	1701	7	26	-9
2501060052	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 1: Splash Filling	1701	7	26	-9
2501060053	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 1: Balanced Submerged Filling	1701	7	26	-9
2501060100	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 2: Total	1701	7	26	-9
2501060100	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 2: Total	1724	7	26	10000
2501060101	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 2: Displacement Loss/Uncontrolled	1701	7	26	-9
2501060102	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 2: Displacement Loss/Controlled	1701	7	26	-9
2501060103	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 2: Spillage	1701	7	26	-9
2501060201	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Underground Tank: Breathing and Emptying	1701	7	26	-9
2501060204	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 2: Off-Highway Equipment Displacement Loss/Controlled	1701	7	26	10000
2501060205	Storage and Transport;Petroleum and Petroleum Product Storage;Gasoline Service Stations;Stage 2: Off-Highway Equipment Spillage	1701	7	26	10000
2501080050	Storage and Transport;Petroleum and Petroleum Product Storage;Airports : Aviation Gasoline;Stage 1: Total	1701	7	26	10000
2501080102	Storage and Transport;Petroleum and Petroleum Product Storage;Airports: Aviation Gasoline;Stage 2: Displacement Loss	1701	7	26	10000
2501080103	Storage and Transport;Petroleum and Petroleum Product Storage;Airports: Aviation Gasoline;Stage 2: Spillage	1701	7	26	10000
2501080201	Storage and Transport;Petroleum and Petroleum Product Storage;Airports: Aviation Gasoline;Underground Tank: Breathing and Emptying	1701	7	26	10000

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2501090050	Storage and Transport;Petroleum and Petroleum Product Storage;Airports: Jet A or JP-8;Stage 1: Total	1701	7	26	10000
2501090060	Storage and Transport;Petroleum and Petroleum Product Storage;Airports: Jet A or JP-8;Stage 2: Total	1701	7	26	10000
2501090070	Storage and Transport;Petroleum and Petroleum Product Storage;Airports: Jet Naphtha or JP-4;Stage 1: Total	1701	7	26	10000
2501090080	Storage and Transport;Petroleum and Petroleum Product Storage;Airports: Jet Naphtha or JP-4;Stage 2: Total	1701	7	26	10000
2501090101	Storage and Transport;Petroleum and Petroleum Product Storage;Airports: Jet A or JP-8;Stage 2: Total	1701	7	26	10000
2501090102	Storage and Transport;Petroleum and Petroleum Product Storage;Marinas: Gasoline;Stage 2: Displacement Loss	1701	7	26	10000
2501090103	Storage and Transport;Petroleum and Petroleum Product Storage;Marinas: Gasoline;Stage 2: Spillage	1701	7	26	10000
2501090201	Storage and Transport;Petroleum and Petroleum Product Storage;Marinas: Gasoline;Underground Tank: Emptying and Breathing	1701	7	26	10000
2505000000	Storage and Transport;Petroleum and Petroleum Product Transport;All Transport Types;Total: All Products	1701	7	26	-9
2610010000	Waste Disposal, Treatment, and Recovery;Open Burning;Industrial;Total	262	9	2013	10000
2630020000	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Total Processed	262	7	24	10000
2630020010	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Wastewater Treatment Processes Total	262	7	24	10000
2630020020	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Biosolids Processes Total	262	7	24	10000
2630020030	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Land Application - Digested Sludge	262	7	24	10000
2630050000	Waste Disposal, Treatment, and Recovery;Wastewater Treatment;Public Owned;Land Application - Digested Sludge	262	7	24	10000
2680001000	Waste Disposal, Treatment, and Recovery;Composting;100% Biosolids (e.g., sewage sludge, manure, mixtures of these matls);All Processes	262	7	26	10000
2730100000	Natural Sources;Geogenic;Wind Erosion;Total	1704	7	26	10000
2801001001	Miscellaneous Area Sources;Agriculture Production - Crops;Corn;Land preparation and cultivation	1703	20	132	10000
2801001005	Miscellaneous Area Sources;Agriculture Production - Crops;Wheat;Land preparation and cultivation	1703	20	132	10000
2801001009	Miscellaneous Area Sources;Agriculture Production - Crops;Barley;Land preparation and cultivation	1703	20	132	10000
2801001013	Miscellaneous Area Sources;Agriculture Production - Crops;Soybeans;Land preparation and cultivation	1703	20	132	10000
2801001017	Miscellaneous Area Sources;Agriculture Production - Crops;Hay/Alfalfa;Land preparation and cultivation	1703	20	132	10000
2801001021	Miscellaneous Area Sources;Agriculture Production - Crops;Vegetables;Land preparation and cultivation	1703	20	132	10000
2801002001	Miscellaneous Area Sources;Agriculture Production - Crops;Corn;Harvesting	1703	20	132	10000
2801002002	Miscellaneous Area Sources;Agriculture Production - Crops;Wheat;Harvesting	1703	20	132	10000
2801002003	Miscellaneous Area Sources;Agriculture Production - Crops;Barley;Harvesting	1703	20	132	10000
2801002004	Miscellaneous Area Sources;Agriculture Production - Crops;Soybeans;Harvesting	1703	20	132	10000
2801002005	Miscellaneous Area Sources;Agriculture Production - Crops;Hay/Alfalfa;Harvesting	1703	20	132	10000
2801002006	Miscellaneous Area Sources;Agriculture Production - Crops;Vegetables;Harvesting	1703	20	132	10000

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2801700020	Miscellaneous Area Sources;Agricultural Production - Crops;Fertilizer Application;Corn	1705	7	26	10000
2801700021	Miscellaneous Area Sources;Agricultural Production - Crops;Fertilizer Application;Sorghum	1705	7	26	10000
2801700022	Miscellaneous Area Sources;Agricultural Production - Crops;Fertilizer Application;Wheat	1705	7	26	10000
2801700023	Miscellaneous Area Sources;Agricultural Production - Crops;Fertilizer Application;Barley	1705	7	26	10000
2801700024	Miscellaneous Area Sources;Agricultural Production - Crops;Fertilizer Application;Soybeans	1705	7	26	10000
2801700025	Miscellaneous Area Sources;Agricultural Production - Crops;Fertilizer Application;Hay/Alfalfa	1705	7	26	10000
2801700026	Miscellaneous Area Sources;Agricultural Production - Crops;Fertilizer Application;Vegetables	1705	7	26	10000
2805001100	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef cattle - finishing operations on feedlots (drylots);Confinement	1706	7	24	10000
2805001200	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef cattle - finishing operations on feedlots (drylots);Manure handling	1706	7	24	10000
2805001300	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef cattle - finishing operations on feedlots (drylots);Land application of	1706	7	24	10000
2805001310	Miscellaneous Area Sources;Agricultural Production - Livestock;Beef Cattle - finishing operations on feedlots (drylots);Land Appl	1706	7	24	10000
2805001320	Miscellaneous Area Sources;Agricultural Production - Livestock;Beef Cattle - finishing operations on feedlots (drylots);Land Appl	1706	7	24	10000
2805001330	Miscellaneous Area Sources;Agricultural Production - Livestock;Beef Cattle - finishing operations on feedlots (drylots);Land Appl	1706	7	24	10000
2805001340	Miscellaneous Area Sources;Agricultural Production - Livestock;Beef Cattle - finishing operations on feedlots (drylots);Land Appl	1706	7	24	10000
2805002000	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef Cattle Composite; Total	1706	7	24	10000
2805007100	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with dry manure management systems;Confinement	262	7	24	10000
2805007200	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - layers with dry manure management systems;Man	262	7	24	10000
2805007300	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with dry manure management systems;Land applicati	262	7	24	10000
2805007340	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - layers with dry manure management systems;Lan	262	7	24	10000
2805008100	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with wet manure management systems;Confinement	262	7	24	10000
2805008200	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - layers with wet manure management systems;Manure handlin	262	7	24	10000
2805008310	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - layers with wet manure management systems;Lan	1708	7	24	10000
2805008320	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - layers with wet manure management systems;Lan	1708	7	24	10000

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2805009100	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - broilers;Confinement	262	7	24	10000
2805009200	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - broilers;Manure handling and storage	262	7	24	10000
2805009330	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - broilers;Land Application of solid manure wit	1708	7	24	10000
2805009340	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - broilers;Land Application of solid manure wit	1708	7	24	10000
2805010100	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - turkeys;Confinement	262	7	24	10000
2805010200	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - turkeys;Manure handling and storage	262	7	24	10000
2805010330	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - turkeys;Land Application of solid manure with	1708	7	24	10000
2805010340	Miscellaneous Area Sources;Agricultural Production - Livestock;Poultry Production - turkeys;Land Application of solid manure with	1708	7	24	10000
2805019100	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - flush dairy;Confinement	1706	7	24	10000
2805019200	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - flush dairy;Manure handling and storage	1706	7	24	10000
2805019300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - flush dairy;Land application of manure	1706	7	24	10000
2805019310	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - flush dairy;Land Application of liquid manure with	1706	7	24	10000
2805019320	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - flush dairy;Land Application of liquid manure witho	1706	7	24	10000
2805019330	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - flush dairy;Land Application of solid manure with i	1706	7	24	10000
2805019340	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - flush dairy;Land Application of solid manure withou	1706	7	24	10000
2805021100	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - scrape dairy;Confinement	1706	7	24	10000
2805021200	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - scrape dairy;Manure handling and storage	1706	7	24	10000
2805021310	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - scrape dairy;Land Application of liquid manure with	1706	7	24	10000
2805021320	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - scrape dairy;Land Application of liquid manure with	1706	7	24	10000
2805021330	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - scrape dairy;Land Application of solid manure with	1706	7	24	10000
2805021340	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - scrape dairy;Land Application of solid manure witho	1706	7	24	10000
2805023100	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - drylot/pasture dairy;Confinement	1706	7	24	10000

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2805023200	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - drylot/pasture dairy;Manure handling and storage	1706	7	24	10000
2805023310	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - drylot/pasture dairy;Land Application of liquid man	1706	7	24	10000
2805023320	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - drylot/pasture dairy;Land Application of liquid man	1706	7	24	10000
2805023330	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - drylot/pasture dairy;Land Application of solid manu	1706	7	24	10000
2805023340	Miscellaneous Area Sources;Agricultural Production - Livestock;Dairy Cattle - drylot/pasture dairy;Land Application of solid manu	1706	7	24	10000
2805035000	Miscellaneous Area Sources;Agriculture Production - Livestock;Horses and Ponies Waste Emissions;Total	262	7	24	10000
2805038100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - operations with lagoons (unspecified animal age);Confineme	1707	7	24	10000
2805038200	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - operations with lagoons (unspecified animal age);Manure ha	1707	7	24	10000
2805038300	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - operations with lagoons (unspecified animal age);Land appl	1707	7	24	10000
2805039100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - operations with lagoons;Confinement	1707	7	24	10000
2805039200	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - operations with lagoons;Manure handling and storage	1707	7	24	10000
2805039310	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - operations with lagoon (unspecified animal age)	1707	7	24	10000
2805039320	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - operations with lagoon (unspecified animal age)	1707	7	24	10000
2805039330	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - operations with lagoon (unspecified animal age)	1707	7	24	10000
2805039340	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - operations with lagoon (unspecified animal age)	1707	7	24	10000
2805040000	Miscellaneous Area Sources;Agriculture Production - Livestock;Sheep and Lambs Waste Emissions;Total	262	7	24	10000
2805045001	Miscellaneous Area Sources;Agriculture Production - Livestock;Goats Waste Emissions;Total	262	7	24	10000
2805046100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - deep-pit house operations (unspecified animal age);Confine	1707	7	24	10000
2805046300	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - deep-pit house operations (unspecified animal age);Land ap	1707	7	24	10000
2805047100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - deep-pit house operations;Confinement	1707	7	24	10000
2805047200	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - deep pit house operations (unspecified animal a	1707	7	24	10000

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2805047310	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - deep pit house operations (unspecified animal a	1707	7	24	10000
2805047320	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - deep pit house operations (unspecified animal a	1707	7	24	10000
2805047330	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - deep pit house operations (unspecified animal a	1707	7	24	10000
2805047340	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - deep pit house operations (unspecified animal a	1707	7	24	10000
2805052100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - outdoor operations (unspecified animal age);Confinement	1707	7	24	10000
2805053100	Miscellaneous Area Sources;Agriculture Production - Livestock;Swine production - outdoor operations; Confinement	1707	7	24	10000
2805053200	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - outdoor operations (unspecified animal age);Man	1707	7	24	10000
2805053310	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - outdoor operations (unspecified animal age);Lan	1707	7	24	10000
2805053320	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - outdoor operations (unspecified animal age);Lan	1707	7	24	10000
2805053330	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - outdoor operations (unspecified animal age);Lan	1707	7	24	10000
2805053340	Miscellaneous Area Sources;Agricultural Production - Livestock;Swine Production - outdoor operations (unspecified animal age);Lan	1707	7	24	10000
2805054000	Miscellaneous Area Sources;Agricultural Production - Livestock;"Mules; Donkeys; and Burros Waste Emissions";Not Elsewhere Classif	262	7	24	10000
2806010000	Miscellaneous Area Sources;Domestic Animals Waste Emissions;Cats;Total	262	7	24	10000
2806015000	Miscellaneous Area Sources;Domestic Animals Waste Emissions;Dogs;Total	262	7	24	10000
2807030000	Miscellaneous Area Sources;Wild Animals Waste Emissions;Deer;Total	262	7	24	10000
2807040000	Miscellaneous Area Sources;Wild Animals Waste Emissions;Birds;Total	262	7	24	10000
2810010000	Miscellaneous Area Sources;Other Combustion;Human Perspiration and Respiration;Total	1739	2006	24	10000
2810015000	Miscellaneous Area Sources;Other Combustion;Prescribed Burning for Forest Management;Total	1731	7	24	10000
2810030000	Miscellaneous Area Sources;Other Combustion;Structure Fires;Total	1715	7	24	10000
2810035000	Miscellaneous Area Sources;Other Combustion;Firefighting Training;Total	1716	2004	24	10000
2870000001	Miscellaneous Area Sources;Humans;Respiration and Perspiration;Total	262	7	24	10000
2870000002	Miscellaneous Area Sources;Humans;Infant Diapered Waste;Total	262	7	24	10000
2870000011	Miscellaneous Area Sources;Domestic Activity;Household Products;Total	262	7	24	10000
2870000015	Miscellaneous Area Sources;Domestic Activity;Non-agricultural Fertilizers;Total	3	7	24	10000

Table VII-6 (continued)

SCC	Description	Month	Week	Diurnal	FIPS
2870000021	Miscellaneous Area Sources;Domestic Animals;Dogs;Total	262	7	24	10000
2870000022	Miscellaneous Area Sources;Domestic Animals;Cats;Total	262	7	24	10000
2870000031	Miscellaneous Area Sources;Wild Animals;Deer;Total	262	7	24	10000
2870000032	Miscellaneous Area Sources;Wild Animals;Birds;Total	1728	7	24	10000

Table VII-7. Point Source Speciation Profiles Added to Speciation Cross-reference File for CB-IV with PM Mechanism

State	FIPS	SCC	Recommended Profiles		Method of Assignment	SCC Description (Complete description not always available)
			VOC	$PM_{2.5}$		
VT	50005	10200908	1084	NWWAS	Use SCC=102009XX profiles	External Combustion Boilers;Industrial;Wood/Bark Waste;Wood-fired Boiler - Dry Wood (<20% moisture)
VT	50019	10200908	1084	NWWAS	Use SCC=102009XX profiles	External Combustion Boilers;Industrial;Wood/Bark Waste;Wood-fired Boiler - Dry Wood (<20% moisture)
VT	50021	10200908	1084	NWWAS	Use SCC=102009XX profiles	External Combustion Boilers;Industrial;Wood/Bark Waste;Wood-fired Boiler - Dry Wood (<20% moisture)
VT	50017	10300908	1084	NWWAS	Use SCC=103009XX profiles	External Combustion Boilers;Commercial/Institutional;Wood/Bark Waste;Wood-fired Boiler - Dry Wood (<20% moisture)
PA	42009	20200299	0007	22004	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42029	20200299	0007	22004	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42045	20200299	0007	22004	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42061	20200299	0007	22004	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42067	20200299	0007	22004	Use SCC=202002XX profiles	Internal Combustion Engines;Industrial;Natural Gas;Unknown
PA	42015	20300299	0007	22004	Use SCC=203002XX profiles	Internal Combustion Engines;Commercial/Institutional;Natural Gas;Unknown
PA	42029	20300299	0007	22004	Use SCC=203002XX profiles	Internal Combustion Engines;Commercial/Institutional;Natural Gas;Unknown
PA	42037	20300299	0007	22004	Use SCC=203002XX profiles	Internal Combustion Engines;Commercial/Institutional;Natural Gas;Unknown
PA	42071	20300299	0007	22004	Use SCC=203002XX profiles	Internal Combustion Engines;Commercial/Institutional;Natural Gas;Unknown
PA	42011	28888899	9002	35602	Use SCC=288888XX profiles	Internal Combustion Engines;Fugitive Emissions;Other Not Classified;Specify in Comments
PA	42123	28888899	9002	35602	Use SCC=288888XX profiles	Internal Combustion Engines;Fugitive Emissions;Other Not Classified;Specify in Comments
PA	42123	28888899	9002	35602	Use SCC=288888XX profiles	Internal Combustion Engines;Fugitive Emissions;Other Not Classified;Specify in Comments
PA	42129	28888899	9002	35602	Use SCC=288888XX profiles	Internal Combustion Engines;Fugitive Emissions;Other Not Classified;Specify in Comments
MD	24031	30500261	0025	22035	Use SCC=30500260 profile	Industrial Processes;Mineral Products;Asphalt Concrete;Drum Mix Plant: Rotary Drum Dryer/Mixer, Waste/Drain/#6 Oil-Fired
PA	Numerous counties	39000698	0000	22004	Use SCC=39000699 profile	Industrial Processes;In-process Fuel Use;Natural Gas;Unknown
NJ	Numerous counties	39999901	9003	22054	Use SCC=399999XX profiles	Industrial Processes;Miscellaneous Manufacturing Industries;Miscellaneous Industrial Processes;Unknown
PA	42015	40202598	1003	99999	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42017	40202598	1003	99999	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42091	40202598	1003	99999	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42095	40202598	1003	99999	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42097	40202598	1003	99999	Use SCC=40202599 profile	Petroleum and Solvent Evaporation;Surface Coating Operations;Miscellaneous Metal Parts;Unknown
PA	42013	40400299	1014	22042	Use SCC=404002XX profiles	Petroleum and Solvent Evaporation;Petroleum Liquids Storage (non-Refinery);Bulk Plants;Unknown
PA	42041	40400299	1014	22042	Use SCC=404002XX profiles	Petroleum and Solvent Evaporation;Petroleum Liquids Storage (non-Refinery);Bulk Plants;Unknown
PA	42045	40400299	1014	22042	Use SCC=404002XX profiles	Petroleum and Solvent Evaporation;Petroleum Liquids Storage (non-Refinery);Bulk Plants;Unknown
PA	42071	40400299	1014	22042	Use SCC=404002XX profiles	Petroleum and Solvent Evaporation;Petroleum Liquids Storage (non-Refinery);Bulk Plants;Unknown

Table VII-8. Point Source SCCs Lacking Speciation Profile Assignments for CB-IV with PM Mechanism

State	FIPS	SCC	Description
NY	36055	31603001	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Substrate Preparation;Extrusion Operations
NY	36055	31603002	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Substrate Preparation;Film Support Operations
NY	36055	31604001	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Chemical Preparation;Chemical Manufacturing
NY	36055	31604002	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Chemical Preparation;Emulsion Making Operations
NY	36055	31604003	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Chemical Preparation;Chemical Mixing Operations
NY	36055	31605001	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Surface Treatments;Surface Coating Operations
NY	36055	31605002	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Surface Treatments;Grid Ionizers
NY	36055	31605003	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Surface Treatments;Corona Discharge Treatment
NY	36055	31606001	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Finishing Operations;General Film Manufacturing
NY	36055	31606002	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Finishing Operations;Cutting/Slitting Operations
PA	42101	31606002	Industrial Processes;Photographic Film Manufacturing;Product Manufacturing - Finishing Operations;Cutting/Slitting Operations
NY	36055	31612001	Industrial Processes;Photographic Film Manufacturing;Support Activities - Cleaning Operations;Tank Cleaning Operations
NY	36055	31612002	Industrial Processes;Photographic Film Manufacturing;Support Activities - Cleaning Operations;General Cleaning Operations
NY	36055	31613002	Industrial Processes;Photographic Film Manufacturing;Support Activities - Storage Operations;General Storage Operations
NY	36055	31614001	Industrial Processes;Photographic Film Manufacturing;Support Activities - Material Transfer Operations;Filling Operations (non petroleum)
NY	36055	31614002	Industrial Processes;Photographic Film Manufacturing;Support Activities - Material Transfer Operations;Transfer of Chemicals
NY	36055	31615001	Industrial Processes;Photographic Film Manufacturing;Support Activities - Separation Processes;Recovery Operations
NY	36055	31615003	Industrial Processes;Photographic Film Manufacturing;Support Activities - Separation Processes;Distillation Operations
NY	36055	31616002	Industrial Processes;Photographic Film Manufacturing;Support Activities - Other Operations;General Process Tank Operations
NY	36055	31616003	Industrial Processes;Photographic Film Manufacturing;Support Activities - Other Operations;Miscellaneous Manufacturing Operations
NY	36055	31616004	Industrial Processes;Photographic Film Manufacturing;Support Activities - Other Operations;Paint Spraying Operations
NY	36055	31616006	Industrial Processes;Photographic Film Manufacturing;Support Activities - Other Operations;Chemical Weighing Operations

Table VII-9. Summary of Version 3 Mass Emissions and SMOKE Input Files

S/L Agencies Included in Files	NIF 3.0 File Name Containing Mass Emissions Inventory (Access 2000 Database Files)	Temporal Period of Mass Emissions Inventory	SMOKE Input File Name	Temporal Period of Emissions in SMOKE/IDA File
Point Source Inventory				
CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA (state and Philadelphia, and Allegheny Counties), RI, VT	MANEVU_2002_Pt_Version 3_040706.mdb	Annual, Summer Day, and Winter Day	MANEVU_Point_SMOKE_INPUT_ANNUAL_SUMMERDAY_042706.txt	Annual and Summer Day
“	“	“	MANEVU_Point_SMOKE_INPUT_ANNUAL_WINTERDAY_042706.txt	Annual and Winter Day
Area Source Inventory				
CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT	MANEVU_2002_Area_040606.mdb	Annual, Summer Day, Winter Day, and Average Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt	Annual, Summer Day, and Average Day
“	“	“	MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt	Annual, Winter Day, and Average Day
Nonroad Source Inventory				
CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT	MANEVU_NRD2002_NIF_030306.mdb	Annual	MANEVU_NRD2002_SMOKE_030306.ida	Annual
Onroad Source Inventory				
CT	CT2002MANEVUORCAP_122004.mdb	Annual		
DE	DE2002MANEVUORCAP_072004.mdb	Annual		
DC	DC2002MANEVUORCAP_072004.mdb	Annual		
ME	ME2002MANEVUORCAP_072004.mdb	Annual		
MD	MD2002MANEVUORCAP_072004.mdb	Annual		
MA	MA2002MANEVUORCAP_022006_Access2000.mdb MA2002MANEVUORCAP_022006_Access97.mdb	Annual		
NH	NH2002MANEVUORCAP_072004.mdb	Annual		
NJ	NJ2002MANEVUORCAP_022006_Access2000.mdb NJ2002MANEVUORCAP_022006_Access97.mdb	Annual		
NY	NY2002MANEVUORCAP_072004.mdb	Annual		
PA	PA2002MANEVUORCAP_072004.mdb	Annual		
RI	DRI2002MANEVUORCAP_072004.mdb	Annual		
VT	VT2002MANEVUORCAP_122004.mdb	Annual		
CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT			MANEVU_2002_mbinv_02022006.txt	
CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT			MANEVU_2002_mcref_02022006.txt	

S/L Agencies Included in Files	NIF 3.0 File Name Containing Mass Emissions Inventory (Access 2000 Database Files)	Temporal Period of Mass Emissions Inventory	SMOKE Input File Name	Temporal Period of Emissions in SMOKE/IDA File
DE, MA, MD, NJ, NY, PA, VT			MANEVU_2002_mtpro_02022006.txt	
DE, MA, MD, NJ, NY, PA, VT			MANEVU_2002_mtref_02022006.txt	
CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT			MANEVU_2002_mvref_02022006.txt	
CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT			MANEVU_2002_vmtmix_02022006.txt	
			MANEVU_2002_mcodes.txt	
CT, NY			MANEVU_2002_spdpro.txt	
CT, NY			MANEVU_2002_spdref.txt	
CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT			SMOKE MOBILE6 input files—too numerous to list individually	

Table VII-10. Unique List of Start Date, End Date, and Emission Type Combinations for Daily Emissions in the MANE-VU 2002 Point and Area Source Inventories, Version 3

Start Date	End Date	Emission Type	Emission Type Period	Season Designation	SMOKE File
Point Source Inventory					
20011201	20020228	27	NONANNUAL	Winter	MANEVU_Point_SMOKE_INPUT_ANNUAL_WINTERDAY_042706.txt
20011201	20020228	29	NONANNUAL	Winter	MANEVU_Point_SMOKE_INPUT_ANNUAL_WINTERDAY_042706.txt
20020101	20020331	27	NONANNUAL	Winter	MANEVU_Point_SMOKE_INPUT_ANNUAL_WINTERDAY_042706.txt
20020101	20021231	29	NONANNUAL	MD-Winter	MANEVU_Point_SMOKE_INPUT_ANNUAL_WINTERDAY_042706.txt
				VT-Summer	MANEVU_Point_SMOKE_INPUT_ANNUAL_SUMMERDAY_042706.txt
20020501	20020930	29	NONANNUAL	Summer	MANEVU_Point_SMOKE_INPUT_ANNUAL_SUMMERDAY_042706.txt
20020601	20020831	27	NONANNUAL	Summer	MANEVU_Point_SMOKE_INPUT_ANNUAL_SUMMERDAY_042706.txt
20020601	20020831	29	NONANNUAL	Summer	MANEVU_Point_SMOKE_INPUT_ANNUAL_SUMMERDAY_042706.txt
20020601	20020831	30	NONANNUAL	Summer	MANEVU_Point_SMOKE_INPUT_ANNUAL_SUMMERDAY_042706.txt
Area Source Inventory					
20020101	20020831	27	Daily	Average Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt and MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt
20020101	20021231	29	Daily	Average Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt and MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt
20020401	20020930	29	Daily	Summer Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt
20020401	20021031	29	Daily	Summer Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt
20020512	20020512	27	Daily	Summer Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt
20020601	20020831	27	Daily	Summer Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt
20020601	20020831	29	Daily	Summer Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt
20020601	20020929	29	Daily	Summer Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt
20020629	20020629	27	Daily	Summer Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt
20011201	20020228	27	Daily	Winter Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt
20011201	20020228	29	Daily	Winter Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt
20021029	20021029	27	Daily	Winter Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt
20021104	20021104	27	Daily	Winter Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt
20021205	20021205	27	Daily	Winter Day	MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt

CHAPTER VIII. METHODS FOR AREAS OUTSIDE OF THE MANE-VU REGION

Figure VIII-1 shows the geographic area for which the 12-kilometer (km) CMAQ modeling domain was used to support air quality modeling for the MANE-VU region. The 36-km domain definition was used for geographical areas outside of the area shown in Figure VIII-1. Table VIII-1 identifies the geographic region as well as the types of emissions inventory and ancillary data used to in modeling for the MANE-VU region. The geographic areas for which data were obtained include the Visibility Improvement State and Tribal Association of the Southeast (VISTAS), Central Regional Air Planning Organization (CENRAP), and WRAP RPOs, the Midwest RPO, Canada, and Mexico.

Figure VIII-1. MANE-VU 12-Kilometer CMAQ Modeling Domain

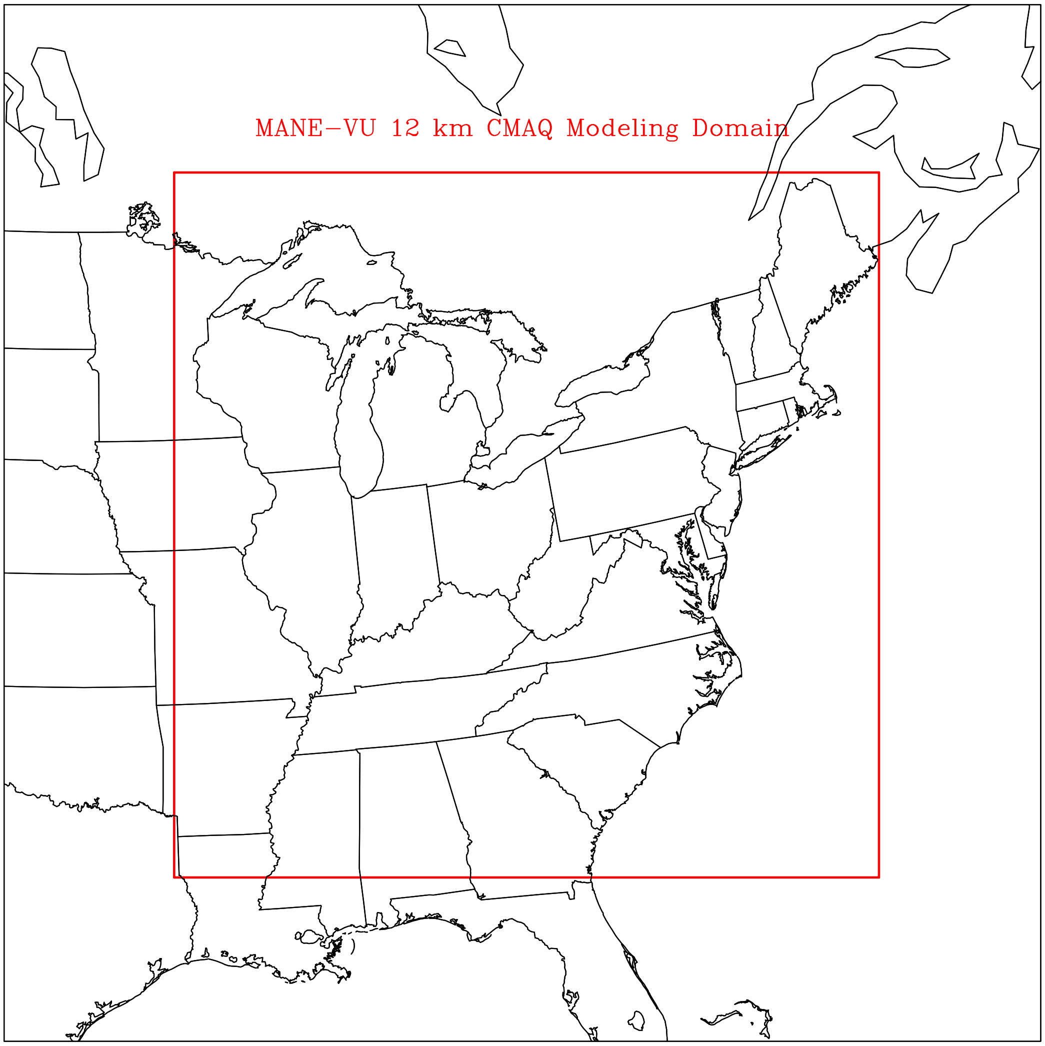


Table VIII-1. Description of Non-MANE-VU Region Inventory Data Used for MANE-VU BaseB Modeling

Geographical Region/RPO	Raw Data	Time Period and Version Number	Raw Data Format	Source of Data	Source of Ancillary Data	Date Data and Summaries Obtained by MANE-VU Modelers
VISTAS	Point, area, nonroad, and mobile	2002 BaseG	SMOKE IDA	Gregory Stella, Alpine Geophysics	Gregory Stella, Alpine Geophysics	June/July 2006
MRPO	Point, area, nonroad, and mobile	2002 BaseK	SMOKE IDA	NIF files provided by Mark Janssen, MRPO, and converted to IDA format by Gregory Stella, Alpine Geophysics	Part of VISTAS 2002 BaseD provided by Gregory Stella, Alpine Geophysics	May 2006
CENRAP	Point, area, nonroad, and mobile	2002 BaseB	SMOKE IDA	CENRAP ftp site Lee Warden, Oklahoma DEQ	CENRAP ftp site Lee Warden, Oklahoma DEQ	March 2006
WRAP *	Point, area, nonroad, and mobile	Part of VISTAS 2002 BaseD	SMOKE IDA	Part of VISTAS 2002 BaseD provided by Gregory Stella, Alpine Geophysics	Part of VISTAS 2002 BaseD provided by Gregory Stella, Alpine Geophysics	January 2005
Canada	Area, nonroad and mobile	2000	SMOKE IDA	ftp://ftp.epa.gov/EmisInventory/canada_2000inventory	SMOKE 2.1 defaults	February 2005
	Point	2002	SMOKE IDA created by NYSDEC from Canadian NPRI database	http://www.ec.gc.ca/pdb/npri/npri_home_e.cfm	SMOKE 2.1 defaults	May 2005
Mexico *	Point, area, nonroad and mobile	1999	SMOKE IDA	EPA CAIR NODA	SMOKE 2.1 defaults	February 2005

* Only utilized for 2002 BaseA 36-km modeling to generate boundary conditions for BaseA/BaseA1/BaseB current and future year 12-km modeling.

CHAPTER IX.   REFERENCES

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APPENDIX A

POINT SOURCE INVENTORY, VERSION 3: DATA SOURCES BY SCC, EMISSION TYPE PERIOD, AND POLLUTANT

[*NOTE: The Appendix A table for each State is provided in a separate MS Word file because of the large size of each table. The Word files are provided in the zip file named "Appendix A.zip"; this zip file also includes an Excel Workbook file that contains the spreadsheet from which the Word file was created for each State.]*

APPENDIX B

AREA SOURCE INVENTORY, VERSION 3: DATA SOURCES BY SCC, EMISSION TYPE PERIOD, AND POLLUTANT

[*NOTE: The Appendix B table for each State is provided in a separate MS Word file because of the large size of each table. The Word files are provided in the zip file named "Appendix B.zip"; this zip file also includes an Excel Workbook file that contains the spreadsheet from which the Word file was created for each State.]*

APPENDIX C

NONROAD SOURCE INVENTORY, VERSION 3: FINAL COUNTY, MONTHLY NATIONAL MOBILE INVENTORY MODEL (NMIM) INPUTS

CONTENTS

Table C-1. MANE-VU County, Monthly NMIM/NONROAD Inputs

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
09	**CONNECTICUT**														
RVP, psi															
		001	Fairfield County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		003	Hartford County	12.3	12.3	10.0	10.0	6.9	6.9	6.9	6.9	6.9	10.0	10.0	12.3
		005	Litchfield County	12.3	12.3	10.0	10.0	6.9	6.9	6.9	6.9	6.9	10.0	10.0	12.3
		007	Middlesex County	12.3	12.3	10.0	10.0	6.9	6.9	6.9	6.9	6.9	10.0	10.0	12.3
		009	New Haven County	12.3	12.3	10.0	10.0	6.9	6.9	6.9	6.9	6.9	10.0	10.0	12.3
		011	New London County	12.3	12.3	10.0	10.0	6.9	6.9	6.9	6.9	6.9	10.0	10.0	12.3
		013	Tolland County	12.3	12.3	10.0	10.0	6.9	6.9	6.9	6.9	6.9	10.0	10.0	12.3
		015	Windham County	12.3	12.3	10.0	10.0	6.9	6.9	6.9	6.9	6.9	10.0	10.0	12.3
Oxygen Weight Percent															
		001	Fairfield County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		003	Hartford County	1.5667	1.5667	1.6068	1.6068	1.6596	1.6596	1.6596	1.6596	1.6596	1.6068	1.6068	1.5667
		005	Litchfield County	1.5667	1.5667	1.6068	1.6068	1.6596	1.6596	1.6596	1.6596	1.6596	1.6068	1.6068	1.5667
		007	Middlesex County	1.5667	1.5667	1.6068	1.6068	1.6596	1.6596	1.6596	1.6596	1.6596	1.6068	1.6068	1.5667
		009	New Haven County	1.5667	1.5667	1.6068	1.6068	1.6596	1.6596	1.6596	1.6596	1.6596	1.6068	1.6068	1.5667
		011	New London County	1.5667	1.5667	1.6068	1.6068	1.6596	1.6596	1.6596	1.6596	1.6596	1.6068	1.6068	1.5667
		013	Tolland County	1.5667	1.5667	1.6068	1.6068	1.6596	1.6596	1.6596	1.6596	1.6596	1.6068	1.6068	1.5667
		015	Windham County	1.5667	1.5667	1.6068	1.6068	1.6596	1.6596	1.6596	1.6596	1.6596	1.6068	1.6068	1.5667
Gasoline Sulfur, ppm															
		001	Fairfield County	135.0	135.0	135.0	135.0	106.0	106.0	106.0	106.0	106.0	135.0	135.0	135.0
		003	Hartford County	135.0	135.0	135.0	135.0	106.0	106.0	106.0	106.0	106.0	135.0	135.0	135.0
		005	Litchfield County	135.0	135.0	135.0	135.0	106.0	106.0	106.0	106.0	106.0	135.0	135.0	135.0
		007	Middlesex County	135.0	135.0	135.0	135.0	106.0	106.0	106.0	106.0	106.0	135.0	135.0	135.0
		009	New Haven County	135.0	135.0	135.0	135.0	106.0	106.0	106.0	106.0	106.0	135.0	135.0	135.0
		011	New London County	135.0	135.0	135.0	135.0	106.0	106.0	106.0	106.0	106.0	135.0	135.0	135.0
		013	Tolland County	135.0	135.0	135.0	135.0	106.0	106.0	106.0	106.0	106.0	135.0	135.0	135.0
		015	Windham County	135.0	135.0	135.0	135.0	106.0	106.0	106.0	106.0	106.0	135.0	135.0	135.0
10	**DELAWARE**														
RVP, psi															
		001	Kent County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		003	New Castle County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		005	Sussex County	13.4	13.4	10.4	10.4	6.4	6.4	6.4	6.4	6.4	10.4	10.4	13.4
Oxygen Weight Percent															
		001	Kent County	1.8442	1.8442	1.9457	1.9457	2.0896	2.0896	2.0896	2.0896	2.0896	1.9457	1.9457	1.8442
		003	New Castle County	1.8442	1.8442	1.9457	1.9457	2.0896	2.0896	2.0896	2.0896	2.0896	1.9457	1.9457	1.8442
		005	Sussex County	1.4645	1.4645	1.5538	1.5538	1.6431	1.6431	1.6431	1.6431	1.6431	1.5538	1.5538	1.4645
Gasoline Sulfur, ppm															
		001	Kent County	174.0	174.0	155.1	155.1	130.0	130.0	130.0	130.0	130.0	155.1	155.1	174.0
		003	New Castle County	174.0	174.0	155.1	155.1	130.0	130.0	130.0	130.0	130.0	155.1	155.1	174.0
		005	Sussex County	225.0	225.0	186.0	186.0	134.0	134.0	134.0	134.0	134.0	186.0	186.0	225.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
11	**DISTRICT OF COLUMBIA**														
RVP, psi															
		001	District of Columbia	13.1	13.1	10.4	10.4	6.8	6.8	6.8	6.8	6.8	6.8	10.4	13.1
Oxygen Weight Percent															
		001	District of Columbia	1.7681	1.7681	1.8217	1.8217	1.8932	1.8932	1.8932	1.8932	1.8932	1.8932	1.8217	1.7681
Gasoline Sulfur, ppm															
		001	District of Columbia	230.0	230.0	199.6	199.6	159.0	159.0	159.0	159.0	159.0	159.0	199.6	230.0
23	**MAINE**														
RVP, psi															
		001	Androscoggin County	12.3	11.1	11.2	8.4	7.5	7.5	7.7	7.3	9.7	10.7	10.3	11.6
		003	Aroostook County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		005	Cumberland County	12.3	11.1	11.2	8.4	7.5	7.5	7.7	7.3	9.7	10.7	10.3	11.6
		007	Franklin County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		009	Hancock County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		011	Kennebec County	12.3	11.1	11.2	8.4	7.5	7.5	7.7	7.3	9.7	10.7	10.3	11.6
		013	Knox County	12.3	11.1	11.2	8.4	7.5	7.5	7.7	7.3	9.7	10.7	10.3	11.6
		015	Lincoln County	12.3	11.1	11.2	8.4	7.5	7.5	7.7	7.3	9.7	10.7	10.3	11.6
		017	Oxford County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		019	Penobscot County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		021	Piscataquis County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		023	Sagadahoc County	12.3	11.1	11.2	8.4	7.5	7.5	7.7	7.3	9.7	10.7	10.3	11.6
		025	Somerset County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		027	Waldo County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		029	Washington County	12.3	11.1	11.2	8.4	8.6	8.6	8.4	8.4	9.7	10.7	10.3	11.6
		031	York County	12.3	11.1	11.2	8.4	7.5	7.5	7.7	7.3	9.7	10.7	10.3	11.6
Oxygen Weight Percent															
		001	Androscoggin County	0.4334	0.6510	0.5390	0.3235	0.2420	0.1753	0.7061	0.6868	0.5895	0.6930	0.3560	0.2080
		003	Aroostook County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		005	Cumberland County	0.4334	0.6510	0.5390	0.3235	0.2420	0.1753	0.7061	0.6868	0.5895	0.6930	0.3560	0.2080
		007	Franklin County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		009	Hancock County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		011	Kennebec County	0.4334	0.6510	0.5390	0.3235	0.2420	0.1753	0.7061	0.6868	0.5895	0.6930	0.3560	0.2080
		013	Knox County	0.4334	0.6510	0.5390	0.3235	0.2420	0.1753	0.7061	0.6868	0.5895	0.6930	0.3560	0.2080
		015	Lincoln County	0.4334	0.6510	0.5390	0.3235	0.2420	0.1753	0.7061	0.6868	0.5895	0.6930	0.3560	0.2080
		017	Oxford County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		019	Penobscot County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		021	Piscataquis County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		023	Sagadahoc County	0.4334	0.6510	0.5390	0.3235	0.2420	0.1753	0.7061	0.6868	0.5895	0.6930	0.3560	0.2080
		025	Somerset County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		027	Waldo County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		029	Washington County	0.4334	0.6510	0.5390	0.3235	0.3786	0.5845	0.8545	0.5448	0.5895	0.6930	0.3560	0.2080
		031	York County	0.4334	0.6510	0.5390	0.3235	0.2420	0.1753	0.7061	0.6868	0.5895	0.6930	0.3560	0.2080
Gasoline Sulfur, ppm															
		001	Androscoggin County	151.5	236.1	221.1	145.4	319.7	268.1	101.1	83.4	159.9	279.8	190.9	171.0
		003	Aroostook County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0
		005	Cumberland County	151.5	236.1	221.1	145.4	319.7	268.1	101.1	83.4	159.9	279.8	190.9	171.0
		007	Franklin County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
23	*MAINE (cont'd)*	009	Hancock County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0
		011	Kennebec County	151.5	236.1	221.1	145.4	319.7	268.1	101.1	83.4	159.9	279.8	190.9	171.0
		013	Knox County	151.5	236.1	221.1	145.4	319.7	268.1	101.1	83.4	159.9	279.8	190.9	171.0
		015	Lincoln County	151.5	236.1	221.1	145.4	319.7	268.1	101.1	83.4	159.9	279.8	190.9	171.0
		017	Oxford County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0
		019	Penobscot County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0
		021	Piscataquis County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0
		023	Sagadahoc County	151.5	236.1	221.1	145.4	319.7	268.1	101.1	83.4	159.9	279.8	190.9	171.0
		025	Somerset County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0
		027	Waldo County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0
		029	Washington County	151.5	236.1	221.1	145.4	170.1	290.9	128.6	299.4	159.9	279.8	190.9	171.0
		031	York County	151.5	236.1	221.1	145.4	319.7	268.1	101.1	83.4	159.9	279.8	190.9	171.0
24	**MARYLAND**														
RVP, psi															
		003	Anne Arundel County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		005	Baltimore County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		009	Calvert County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		011	Caroline County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		013	Carroll County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		015	Cecil County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		017	Charles County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		019	Dorchester County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		021	Frederick County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		023	Garrett County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		025	Harford County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		027	Howard County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		029	Kent County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		031	Montgomery County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		033	Prince George's County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		035	Queen Anne's County	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
		037	St. Mary's County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		039	Somerset County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		041	Talbot County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		043	Washington County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		045	Wicomico County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		047	Worcester County	12.6	12.6	9.6	9.6	9.6	8.2	8.2	8.2	9.3	9.3	9.3	12.6
		510	Baltimore city	12.6	12.6	9.6	9.6	9.6	6.6	6.6	6.6	9.3	9.3	9.3	12.6
Oxygen Weight Percent															
		001	Allegany County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		003	Anne Arundel County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		005	Baltimore County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		009	Calvert County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		011	Caroline County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		013	Carroll County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		015	Cecil County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		017	Charles County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		019	Dorchester County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		021	Frederick County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
24	*MARYLAND (cont'd)*	023	Garrett County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		025	Harford County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		027	Howard County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		029	Kent County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		031	Montgomery County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		033	Prince George's County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		035	Queen Anne's County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		037	St. Mary's County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		039	Somerset County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		041	Talbot County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		043	Washington County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		045	Wicomico County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		047	Worcester County	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
		510	Baltimore city	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075	2.1075
Gasoline Sulfur, ppm															
		001	Allegany County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		003	Anne Arundel County	211.0	211.0	184.0	129.0	129.0	129.0	129.0	129.0	129.0	148.0	184.0	211.0
		005	Baltimore County	211.0	211.0	184.0	129.0	129.0	129.0	129.0	129.0	129.0	148.0	184.0	211.0
		009	Calvert County	230.0	230.0	199.6	129.0	129.0	129.0	129.0	129.0	129.0	159.0	199.6	230.0
		011	Caroline County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		013	Carroll County	211.0	211.0	184.0	129.0	129.0	129.0	129.0	129.0	129.0	148.0	184.0	211.0
		015	Cecil County	174.0	174.0	155.1	129.0	129.0	129.0	129.0	129.0	129.0	130.0	155.1	174.0
		017	Charles County	230.0	230.0	199.6	129.0	129.0	129.0	129.0	129.0	129.0	159.0	199.6	230.0
		019	Dorchester County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		021	Frederick County	230.0	230.0	199.6	129.0	129.0	129.0	129.0	129.0	129.0	159.0	199.6	230.0
		023	Garrett County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		025	Harford County	211.0	211.0	184.0	129.0	129.0	129.0	129.0	129.0	129.0	148.0	184.0	211.0
		027	Howard County	211.0	211.0	184.0	129.0	129.0	129.0	129.0	129.0	129.0	148.0	184.0	211.0
		029	Kent County	174.0	174.0	155.1	129.0	129.0	129.0	129.0	129.0	129.0	130.0	155.1	174.0
		031	Montgomery County	230.0	230.0	199.6	129.0	129.0	129.0	129.0	129.0	129.0	159.0	199.6	230.0
		033	Prince George's County	230.0	230.0	199.6	129.0	129.0	129.0	129.0	129.0	129.0	159.0	199.6	230.0
		035	Queen Anne's County	174.0	174.0	155.1	129.0	129.0	129.0	129.0	129.0	129.0	130.0	155.1	174.0
		037	St. Mary's County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		039	Somerset County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		041	Talbot County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		043	Washington County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		045	Wicomico County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		047	Worcester County	207.9	207.9	191.9	191.9	170.5	170.5	170.5	170.5	170.5	170.5	191.9	207.9
		510	Baltimore city	211.0	211.0	184.0	129.0	129.0	129.0	129.0	129.0	129.0	148.0	184.0	211.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
25	**MASSACHUSETTS**														
RVP, psi															
		001	Barnstable County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		003	Berkshire County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		005	Bristol County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		007	Dukes County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		009	Essex County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		011	Franklin County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		013	Hampden County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		015	Hampshire County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		017	Middlesex County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		019	Nantucket County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		021	Norfolk County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		023	Plymouth County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		025	Suffolk County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
		027	Worcester County	13.5	13.5	13.5	13.5	6.7	6.7	6.7	6.7	6.7	13.5	13.5	13.5
Oxygen Weight Percent															
		001	Barnstable County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		003	Berkshire County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		005	Bristol County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		007	Dukes County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		009	Essex County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		011	Franklin County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		013	Hampden County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		015	Hampshire County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		017	Middlesex County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		019	Nantucket County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		021	Norfolk County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		023	Plymouth County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		025	Suffolk County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
		027	Worcester County	1.5002	1.5002	1.5002	1.5002	2.1075	2.1075	2.1075	2.1075	2.1075	1.5002	1.5002	1.5002
Gasoline Sulfur, ppm															
		001	Barnstable County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		003	Berkshire County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		005	Bristol County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		007	Dukes County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		009	Essex County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		011	Franklin County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		013	Hampden County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		015	Hampshire County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		017	Middlesex County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		019	Nantucket County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		021	Norfolk County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		023	Plymouth County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		025	Suffolk County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		027	Worcester County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
33	**NEW HAMPSHIRE**														
RVP, psi															
		001	Belknap County	13.6	13.6	11.2	11.2	7.9	7.9	7.9	7.9	7.9	11.2	11.2	13.6
		003	Carroll County	13.6	13.6	11.2	11.2	7.9	7.9	7.9	7.9	7.9	11.2	11.2	13.6
		005	Cheshire County	13.6	13.6	11.2	11.2	7.9	7.9	7.9	7.9	7.9	11.2	11.2	13.6
		007	Coos County	13.6	13.6	11.2	11.2	7.9	7.9	7.9	7.9	7.9	11.2	11.2	13.6
		009	Grafton County	13.6	13.6	11.2	11.2	7.9	7.9	7.9	7.9	7.9	11.2	11.2	13.6
		011	Hillsborough County	12.9	12.9	10.2	10.2	6.7	6.7	6.7	6.7	6.7	10.2	10.2	12.9
		013	Merrimack County	12.9	12.9	10.2	10.2	6.7	6.7	6.7	6.7	6.7	10.2	10.2	12.9
		015	Rockingham County	12.9	12.9	10.2	10.2	6.7	6.7	6.7	6.7	6.7	10.2	10.2	12.9
		017	Strafford County	12.9	12.9	10.2	10.2	6.7	6.7	6.7	6.7	6.7	10.2	10.2	12.9
		019	Sullivan County	13.6	13.6	11.2	11.2	7.9	7.9	7.9	7.9	7.9	11.2	11.2	13.6
Oxygen Weight Percent															
		001	Belknap County	0.1786	0.1786	0.2322	0.2322	0.2858	0.2858	0.2858	0.2858	0.2858	0.2322	0.2322	0.1786
		003	Carroll County	0.1786	0.1786	0.2322	0.2322	0.2858	0.2858	0.2858	0.2858	0.2858	0.2322	0.2322	0.1786
		005	Cheshire County	0.1786	0.1786	0.2322	0.2322	0.2858	0.2858	0.2858	0.2858	0.2858	0.2322	0.2322	0.1786
		007	Coos County	0.1786	0.1786	0.2322	0.2322	0.2858	0.2858	0.2858	0.2858	0.2858	0.2322	0.2322	0.1786
		009	Grafton County	0.1786	0.1786	0.2322	0.2322	0.2858	0.2858	0.2858	0.2858	0.2858	0.2322	0.2322	0.1786
		011	Hillsborough County	1.8217	1.8217	1.9110	1.9110	2.0182	2.0182	2.0182	2.0182	2.0182	1.9110	1.9110	1.8217
		013	Merrimack County	1.8217	1.8217	1.9110	1.9110	2.0182	2.0182	2.0182	2.0182	2.0182	1.9110	1.9110	1.8217
		015	Rockingham County	1.9825	1.9825	2.0539	2.0539	2.1432	2.1432	2.1432	2.1432	2.1432	2.0539	2.0539	1.9825
		017	Strafford County	1.9825	1.9825	2.0539	2.0539	2.1432	2.1432	2.1432	2.1432	2.1432	2.0539	2.0539	1.9825
		019	Sullivan County	0.1786	0.1786	0.2322	0.2322	0.2858	0.2858	0.2858	0.2858	0.2858	0.2322	0.2322	0.1786
Gasoline Sulfur, ppm															
		001	Belknap County	228.1	228.1	208.6	208.6	182.5	182.5	182.5	182.5	182.5	208.6	208.6	228.1
		003	Carroll County	228.1	228.1	208.6	208.6	182.5	182.5	182.5	182.5	182.5	208.6	208.6	228.1
		005	Cheshire County	228.1	228.1	208.6	208.6	182.5	182.5	182.5	182.5	182.5	208.6	208.6	228.1
		007	Coos County	228.1	228.1	208.6	208.6	182.5	182.5	182.5	182.5	182.5	208.6	208.6	228.1
		009	Grafton County	228.1	228.1	208.6	208.6	182.5	182.5	182.5	182.5	182.5	208.6	208.6	228.1
		011	Hillsborough County	121.0	121.0	101.3	101.3	75.0	75.0	75.0	75.0	75.0	101.3	101.3	121.0
		013	Merrimack County	121.0	121.0	101.3	101.3	75.0	75.0	75.0	75.0	75.0	101.3	101.3	121.0
		015	Rockingham County	148.0	148.0	121.0	121.0	85.0	85.0	85.0	85.0	85.0	121.0	121.0	148.0
		017	Strafford County	148.0	148.0	121.0	121.0	85.0	85.0	85.0	85.0	85.0	121.0	121.0	148.0
		019	Sullivan County	228.1	228.1	208.6	208.6	182.5	182.5	182.5	182.5	182.5	208.6	208.6	228.1
34	**NEW JERSEY**														
RVP, psi															
		001	Atlantic County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		003	Bergen County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		005	Burlington County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		007	Camden County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		009	Cape May County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		011	Cumberland County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		013	Essex County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		015	Gloucester County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		017	Hudson County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		019	Hunterdon County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		021	Mercer County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		023	Middlesex County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
34	*NEW JERSEY (cont'd)*	025	Monmouth County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		027	Morris County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		029	Ocean County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		031	Passaic County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		033	Salem County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
		035	Somerset County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		037	Sussex County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		039	Union County	12.5	12.5	10.1	10.1	6.8	6.8	6.8	6.8	6.8	10.1	10.1	12.5
		041	Warren County	13.4	13.4	10.6	10.6	6.8	6.8	6.8	6.8	6.8	10.6	10.6	13.4
Oxygen Weight Percent															
		001	Atlantic County	1.6922	1.6922	1.8499	1.8499	2.0718	2.0718	2.0718	2.0718	2.0718	1.8499	1.8499	1.6922
		003	Bergen County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		005	Burlington County	1.8442	1.8442	1.9457	1.9457	2.0896	2.0896	2.0896	2.0896	2.0896	1.9457	1.9457	1.8442
		007	Camden County	1.8442	1.8442	1.9457	1.9457	2.0896	2.0896	2.0896	2.0896	2.0896	1.9457	1.9457	1.8442
		009	Cape May County	1.6922	1.6922	1.8499	1.8499	2.0718	2.0718	2.0718	2.0718	2.0718	1.8499	1.8499	1.6922
		011	Cumberland County	1.8442	1.8442	1.9457	1.9457	2.0896	2.0896	2.0896	2.0896	2.0896	1.9457	1.9457	1.8442
		013	Essex County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		015	Gloucester County	1.8442	1.8442	1.9457	1.9457	2.0896	2.0896	2.0896	2.0896	2.0896	1.9457	1.9457	1.8442
		017	Hudson County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		019	Hunterdon County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		021	Mercer County	1.8442	1.8442	1.9457	1.9457	2.0896	2.0896	2.0896	2.0896	2.0896	1.9457	1.9457	1.8442
		023	Middlesex County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		025	Monmouth County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		027	Morris County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		029	Ocean County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		031	Passaic County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		033	Salem County	1.8442	1.8442	1.9457	1.9457	2.0896	2.0896	2.0896	2.0896	2.0896	1.9457	1.9457	1.8442
		035	Somerset County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		037	Sussex County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		039	Union County	1.7172	1.7172	1.7660	1.7660	1.8234	1.8234	1.8234	1.8234	1.8234	1.7660	1.7660	1.7172
		041	Warren County	1.8753	1.8753	1.9110	1.9110	1.9825	1.9825	1.9825	1.9825	1.9825	1.9110	1.9110	1.8753
Gasoline Sulfur, ppm															
		001	Atlantic County	207.0	207.0	174.0	174.0	130.0	130.0	130.0	130.0	130.0	174.0	174.0	207.0
		003	Bergen County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		005	Burlington County	174.0	174.0	155.1	155.1	130.0	130.0	130.0	130.0	130.0	155.1	155.1	174.0
		007	Camden County	174.0	174.0	155.1	155.1	130.0	130.0	130.0	130.0	130.0	155.1	155.1	174.0
		009	Cape May County	207.0	207.0	174.0	174.0	130.0	130.0	130.0	130.0	130.0	174.0	174.0	207.0
		011	Cumberland County	174.0	174.0	155.1	155.1	130.0	130.0	130.0	130.0	130.0	155.1	155.1	174.0
		013	Essex County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		015	Gloucester County	174.0	174.0	155.1	155.1	130.0	130.0	130.0	130.0	130.0	155.1	155.1	174.0
		017	Hudson County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		019	Hunterdon County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		021	Mercer County	174.0	174.0	155.1	155.1	130.0	130.0	130.0	130.0	130.0	155.1	155.1	174.0
		023	Middlesex County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		025	Monmouth County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		027	Morris County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		029	Ocean County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		031	Passaic County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
34	*NEW JERSEY (cont'd)*	033	Salem County	174.0	174.0	155.1	155.1	130.0	130.0	130.0	130.0	130.0	155.1	155.1	174.0
		035	Somerset County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		037	Sussex County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		039	Union County	141.0	141.0	129.4	129.4	114.0	114.0	114.0	114.0	114.0	129.4	129.4	141.0
		041	Warren County	125.0	125.0	123.7	123.7	122.0	122.0	122.0	122.0	122.0	123.7	123.7	125.0
36	**NEW YORK**														
RVP, psi															
		001	Albany County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		003	Allegany County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		005	Bronx County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		007	Broome County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		009	Cattaraugus County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		011	Cayuga County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		013	Chautauqua County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		015	Chemung County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		017	Chenango County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		019	Clinton County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		021	Columbia County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		023	Cortland County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		025	Delaware County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		027	Dutchess County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		029	Erie County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		031	Essex County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		033	Franklin County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		035	Fulton County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		037	Genesee County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		039	Greene County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		041	Hamilton County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		043	Herkimer County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		045	Jefferson County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		047	Kings County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		049	Lewis County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		051	Livingston County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		053	Madison County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		055	Monroe County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		057	Montgomery County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		059	Nassau County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		061	New York County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		063	Niagara County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		065	Oneida County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		067	Onondaga County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		069	Ontario County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		071	Orange County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		073	Orleans County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		075	Oswego County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		077	Otsego County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		079	Putnam County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		081	Queens County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
36	*NEW YORK*	083	Rensselaer County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
	(cont'd)	085	Richmond County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		087	Rockland County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		089	St. Lawrence County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		091	Saratoga County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		093	Schenectady County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		095	Schoharie County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		097	Schuyler County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		099	Seneca County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		101	Steuben County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		103	Suffolk County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		105	Sullivan County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		107	Tioga County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		109	Tompkins County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		111	Ulster County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		113	Warren County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		115	Washington County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		117	Wayne County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		119	Westchester County	12.8	12.6	12.1	9.0	6.8	6.7	6.6	6.7	6.9	10.3	11.7	12.5
		121	Wyoming County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
		123	Yates County	12.7	12.7	12.6	10.9	8.6	8.3	8.3	8.2	8.2	9.6	10.7	11.4
Oxygen Weight Percent															
		001	Albany County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		003	Allegany County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		005	Bronx County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		007	Broome County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		009	Cattaraugus County	0.8965	1.0344	0.8275	0.6551	0.8965	0.5862	0.8275	0.9654	0.6551	0.6896	0.9310	0.8965
		011	Cayuga County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		013	Chautauqua County	0.8965	1.0344	0.8275	0.6551	0.8965	0.5862	0.8275	0.9654	0.6551	0.6896	0.9310	0.8965
		015	Chemung County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		017	Chenango County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		019	Clinton County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		021	Columbia County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		023	Cortland County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		025	Delaware County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		027	Dutchess County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		029	Erie County	0.8965	1.0344	0.8275	0.6551	0.8965	0.5862	0.8275	0.9654	0.6551	0.6896	0.9310	0.8965
		031	Essex County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		033	Franklin County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		035	Fulton County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		037	Genesee County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		039	Greene County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		041	Hamilton County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		043	Herkimer County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		045	Jefferson County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		047	Kings County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		049	Lewis County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		051	Livingston County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		053	Madison County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
36	*NEW YORK*	055	Monroe County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
	(cont'd)	057	Montgomery County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		059	Nassau County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		061	New York County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		063	Niagara County	0.8965	1.0344	0.8275	0.6551	0.8965	0.5862	0.8275	0.9654	0.6551	0.6896	0.9310	0.8965
		065	Oneida County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		067	Onondaga County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		069	Ontario County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		071	Orange County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		073	Orleans County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		075	Oswego County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		077	Otsego County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		079	Putnam County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		081	Queens County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		083	Rensselaer County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		085	Richmond County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		087	Rockland County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		089	St. Lawrence County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		091	Saratoga County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		093	Schenectady County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		095	Schoharie County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		097	Schuyler County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		099	Seneca County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		101	Steuben County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		103	Suffolk County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		105	Sullivan County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		107	Tioga County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		109	Tompkins County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		111	Ulster County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		113	Warren County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		115	Washington County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		117	Wayne County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		119	Westchester County	1.8932	1.9467	1.8932	1.8753	1.9646	1.9467	1.9646	1.8217	1.9646	1.8217	1.8574	1.6431
		121	Wyoming County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
		123	Yates County	0.8751	1.0180	0.8216	0.6430	0.8930	0.5894	0.8216	0.9466	0.6787	0.6965	0.9466	0.8930
Gasoline Sulfur, ppm															
		001	Albany County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		003	Allegany County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		005	Bronx County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		007	Broome County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		009	Cattaraugus County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		011	Cayuga County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		013	Chautauqua County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		015	Chemung County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		017	Chenango County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		019	Clinton County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		021	Columbia County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		023	Cortland County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		025	Delaware County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
36	*NEW YORK*	027	Dutchess County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
	(cont'd)	029	Erie County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		031	Essex County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		033	Franklin County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		035	Fulton County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		037	Genesee County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		039	Greene County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		041	Hamilton County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		043	Herkimer County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		045	Jefferson County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		047	Kings County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		049	Lewis County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		051	Livingston County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		053	Madison County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		055	Monroe County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		057	Montgomery County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		059	Nassau County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		061	New York County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		063	Niagara County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		065	Oneida County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		067	Onondaga County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		069	Ontario County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		071	Orange County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		073	Orleans County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		075	Oswego County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		077	Otsego County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		079	Putnam County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		081	Queens County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		083	Rensselaer County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		085	Richmond County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		087	Rockland County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		089	St. Lawrence County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		091	Saratoga County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		093	Schenectady County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		095	Schoharie County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		097	Schuyler County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		099	Seneca County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		101	Steuben County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		103	Suffolk County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		105	Sullivan County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		107	Tioga County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		109	Tompkins County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		111	Ulster County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		113	Warren County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		115	Washington County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		117	Wayne County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		119	Westchester County	210.0	220.0	180.0	200.0	220.0	210.0	220.0	190.0	190.0	220.0	200.0	240.0
		121	Wyoming County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0
		123	Yates County	260.0	250.0	250.0	230.0	310.0	320.0	340.0	290.0	270.0	250.0	250.0	210.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
42	**PENNSYLVANIA**														
RVP, psi															
		001	Adams County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		003	Allegheny County	13.5	13.5	11.0	11.0	7.8	7.8	7.8	7.8	7.8	11.0	11.0	13.5
		005	Armstrong County	13.5	13.5	11.0	11.0	7.8	7.8	7.8	7.8	7.8	11.0	11.0	13.5
		007	Beaver County	13.5	13.5	11.0	11.0	7.8	7.8	7.8	7.8	7.8	11.0	11.0	13.5
		009	Bedford County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		011	Berks County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		013	Blair County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		015	Bradford County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		017	Bucks County	13.5	13.5	10.6	10.6	6.7	6.7	6.7	6.7	6.7	10.6	10.6	13.5
		019	Butler County	13.5	13.5	11.0	11.0	7.8	7.8	7.8	7.8	7.8	11.0	11.0	13.5
		021	Cambria County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		023	Cameron County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		025	Carbon County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		027	Centre County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		029	Chester County	13.5	13.5	10.6	10.6	6.7	6.7	6.7	6.7	6.7	10.6	10.6	13.5
		031	Clarion County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		033	Clearfield County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		035	Clinton County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		037	Columbia County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		039	Crawford County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		041	Cumberland County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		043	Dauphin County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		045	Delaware County	13.5	13.5	10.6	10.6	6.7	6.7	6.7	6.7	6.7	10.6	10.6	13.5
		047	Elk County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		049	Erie County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		051	Fayette County	13.5	13.5	11.0	11.0	7.8	7.8	7.8	7.8	7.8	11.0	11.0	13.5
		053	Forest County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		055	Franklin County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		057	Fulton County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		059	Greene County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		061	Huntingdon County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		063	Indiana County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		065	Jefferson County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		067	Juniata County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		069	Lackawanna County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		071	Lancaster County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		073	Lawrence County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		075	Lebanon County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		077	Lehigh County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		079	Luzerne County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		081	Lycoming County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		083	McKean County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		085	Mercer County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		087	Mifflin County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		089	Monroe County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		091	Montgomery County	13.5	13.5	10.6	10.6	6.7	6.7	6.7	6.7	6.7	10.6	10.6	13.5
		093	Montour County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
42	*PENNSYLVANIA (cont'd)*	095	Northampton County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		097	Northumberland County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		099	Perry County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		101	Philadelphia County	13.5	13.5	10.6	10.6	6.7	6.7	6.7	6.7	6.7	10.6	10.6	13.5
		103	Pike County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		105	Potter County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		107	Schuylkill County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		109	Snyder County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		111	Somerset County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		113	Sullivan County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		115	Susquehanna County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		117	Tioga County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		119	Union County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		121	Venango County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		123	Warren County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		125	Washington County	13.5	13.5	11.0	11.0	7.8	7.8	7.8	7.8	7.8	11.0	11.0	13.5
		127	Wayne County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		129	Westmoreland County	13.5	13.5	11.0	11.0	7.8	7.8	7.8	7.8	7.8	11.0	11.0	13.5
		131	Wyoming County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
		133	York County	13.5	13.5	11.0	11.0	8.7	8.7	8.7	8.7	8.7	11.0	11.0	13.5
Oxygen Weight Percent															
		001	Adams County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		003	Allegheny County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		005	Armstrong County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		007	Beaver County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		009	Bedford County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		011	Berks County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		013	Blair County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		015	Bradford County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		017	Bucks County	2.5303	2.5303	2.5303	2.5303	2.1075	2.1075	2.1075	2.1075	2.1075	2.5303	2.5303	2.5303
		019	Butler County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		021	Cambria County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		023	Cameron County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		025	Carbon County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		027	Centre County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		029	Chester County	2.5303	2.5303	2.5303	2.5303	2.1075	2.1075	2.1075	2.1075	2.1075	2.5303	2.5303	2.5303
		031	Clarion County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		033	Clearfield County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		035	Clinton County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		037	Columbia County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		039	Crawford County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		041	Cumberland County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		043	Dauphin County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		045	Delaware County	2.5303	2.5303	2.5303	2.5303	2.1075	2.1075	2.1075	2.1075	2.1075	2.5303	2.5303	2.5303
		047	Elk County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		049	Erie County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		051	Fayette County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		053	Forest County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		055	Franklin County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
42	*PENNSYLVANIA (cont'd)*	057	Fulton County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		059	Greene County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		061	Huntingdon County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		063	Indiana County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		065	Jefferson County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		067	Juniata County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		069	Lackawanna County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		071	Lancaster County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		073	Lawrence County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		075	Lebanon County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		077	Lehigh County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		079	Luzerne County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		081	Lycoming County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		083	McKean County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		085	Mercer County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		087	Mifflin County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		089	Monroe County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		091	Montgomery County	2.5303	2.5303	2.5303	2.5303	2.1075	2.1075	2.1075	2.1075	2.1075	2.5303	2.5303	2.5303
		093	Montour County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		095	Northampton County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		097	Northumberland County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		099	Perry County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		101	Philadelphia County	2.5303	2.5303	2.5303	2.5303	2.1075	2.1075	2.1075	2.1075	2.1075	2.5303	2.5303	2.5303
		103	Pike County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		105	Potter County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		107	Schuylkill County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		109	Snyder County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		111	Somerset County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		113	Sullivan County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		115	Susquehanna County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		117	Tioga County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		119	Union County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		121	Venango County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		123	Warren County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		125	Washington County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		127	Wayne County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		129	Westmoreland County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		131	Wyoming County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
		133	York County	0.1965	0.1965	0.2322	0.2322	0.2679	0.2679	0.2679	0.2679	0.2679	0.2322	0.2322	0.1965
Gasoline Sulfur, ppm															
		001	Adams County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		003	Allegheny County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		005	Armstrong County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		007	Beaver County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		009	Bedford County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		011	Berks County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		013	Blair County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		015	Bradford County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		017	Bucks County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
42	*PENNSYLVANIA (cont'd)*	019	Butler County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		021	Cambria County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		023	Cameron County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		025	Carbon County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		027	Centre County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		029	Chester County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		031	Clarion County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		033	Clearfield County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		035	Clinton County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		037	Columbia County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		039	Crawford County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		041	Cumberland County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		043	Dauphin County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		045	Delaware County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		047	Elk County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		049	Erie County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		051	Fayette County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		053	Forest County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		055	Franklin County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		057	Fulton County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		059	Greene County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		061	Huntingdon County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		063	Indiana County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		065	Jefferson County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		067	Juniata County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		069	Lackawanna County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		071	Lancaster County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		073	Lawrence County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		075	Lebanon County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		077	Lehigh County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		079	Luzerne County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		081	Lycoming County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		083	McKean County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		085	Mercer County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		087	Mifflin County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		089	Monroe County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		091	Montgomery County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		093	Montour County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		095	Northampton County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		097	Northumberland County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		099	Perry County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		101	Philadelphia County	279.0	279.0	279.0	279.0	129.0	129.0	129.0	129.0	129.0	279.0	279.0	279.0
		103	Pike County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		105	Potter County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		107	Schuylkill County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		109	Snyder County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		111	Somerset County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		113	Sullivan County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		115	Susquehanna County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
42	*PENNSYLVANIA (cont'd)*	117	Tioga County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		119	Union County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		121	Venango County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		123	Warren County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		125	Washington County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		127	Wayne County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		129	Westmoreland County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		131	Wyoming County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
		133	York County	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0	279.0
44	**RHODE ISLAND**														
RVP, psi															
		001	Bristol County	12.5	12.5	10.1	10.1	6.9	6.9	6.9	6.9	6.9	10.1	10.1	12.5
		003	Kent County	12.5	12.5	10.1	10.1	6.9	6.9	6.9	6.9	6.9	10.1	10.1	12.5
		005	Newport County	12.5	12.5	10.1	10.1	6.9	6.9	6.9	6.9	6.9	10.1	10.1	12.5
		007	Providence County	12.5	12.5	10.1	10.1	6.9	6.9	6.9	6.9	6.9	10.1	10.1	12.5
		009	Washington County	12.5	12.5	10.1	10.1	6.9	6.9	6.9	6.9	6.9	10.1	10.1	12.5
Oxygen Weight Percent															
		001	Bristol County	1.7110	1.7110	1.6801	1.6801	1.6745	1.6745	1.6745	1.6745	1.6745	1.6801	1.6801	1.7110
		003	Kent County	1.7110	1.7110	1.6801	1.6801	1.6745	1.6745	1.6745	1.6745	1.6745	1.6801	1.6801	1.7110
		005	Newport County	1.7110	1.7110	1.6801	1.6801	1.6745	1.6745	1.6745	1.6745	1.6745	1.6801	1.6801	1.7110
		007	Providence County	1.7110	1.7110	1.6801	1.6801	1.6745	1.6745	1.6745	1.6745	1.6745	1.6801	1.6801	1.7110
		009	Washington County	1.7110	1.7110	1.6801	1.6801	1.6745	1.6745	1.6745	1.6745	1.6745	1.6801	1.6801	1.7110
Gasoline Sulfur, ppm															
		001	Bristol County	193.0	193.0	166.4	166.4	131.0	131.0	131.0	131.0	131.0	166.4	166.4	193.0
		003	Kent County	193.0	193.0	166.4	166.4	131.0	131.0	131.0	131.0	131.0	166.4	166.4	193.0
		005	Newport County	193.0	193.0	166.4	166.4	131.0	131.0	131.0	131.0	131.0	166.4	166.4	193.0
		007	Providence County	193.0	193.0	166.4	166.4	131.0	131.0	131.0	131.0	131.0	166.4	166.4	193.0
		009	Washington County	193.0	193.0	166.4	166.4	131.0	131.0	131.0	131.0	131.0	166.4	166.4	193.0

Table C-1 (continued)

FIPS_State	State	FIPS_County	County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
50	**VERMONT**														
RVP, psi															
		001	Addison County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		003	Bennington County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		005	Caledonia County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		007	Chittenden County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		009	Essex County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		011	Franklin County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		013	Grand Isle County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		015	Lamoille County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		017	Orange County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		019	Orleans County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		021	Rutland County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		023	Washington County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		025	Windham County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
		027	Windsor County	9.5	9.5	9.5	9.5	8.5	8.5	8.5	8.5	8.5	9.5	9.5	9.5
Oxygen Weight Percent															
		001	Addison County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		003	Bennington County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		005	Caledonia County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		007	Chittenden County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		009	Essex County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		011	Franklin County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		013	Grand Isle County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		015	Lamoille County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		017	Orange County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		019	Orleans County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		021	Rutland County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		023	Washington County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		025	Windham County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
		027	Windsor County	0.1786	0.1786	0.2143	0.2143	0.2679	0.2679	0.2679	0.2679	0.2679	0.2143	0.2143	0.1786
Gasoline Sulfur, ppm															
		001	Addison County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		003	Bennington County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		005	Caledonia County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		007	Chittenden County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		009	Essex County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		011	Franklin County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		013	Grand Isle County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		015	Lamoille County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		017	Orange County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		019	Orleans County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		021	Rutland County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		023	Washington County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		025	Windham County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3
		027	Windsor County	209.3	209.3	209.3	209.3	183.1	183.1	183.1	183.1	183.1	209.3	209.3	209.3

Technical Support Document on
Agricultural and Forestry Smoke Management in the MANE-VU Region

Draft: March 2, 2006

1. Introduction

This technical support document aims to provide States with information useful in addressing agricultural and forestry smoke management in their State Implementation Plans (SIP). This document may also be useful for tribes in MANE-VU that choose to include smoke management issues in their Tribal Implementation Plans (TIP).

Each State must develop a long-term (10-15 years) strategy for making reasonable progress towards the national goal stated in 40 CFR 51.300(a), "preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution." States are required to develop long-term strategies for each mandatory Class I Federal area located within the state and each mandatory Class I Federal area located outside the state that may be affected by sources within the state. According to 40 CFR section 51.308(d)(3)(v)(E), States must consider "smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the State for these purposes" in developing its long-term strategy.

Prior to developing their Regional Haze SIP/TIP, States/tribes must consider the air quality and visibility impacts of fires in the Region and evaluate whether their existing approaches to regulating fires are adequate. States must determine whether or not smoke management is necessary to mitigate the impacts of fires to meet the 2018 reasonable progress goals for Class I Areas. If smoke management policies are required for a particular Class I Area, then a smoke management program (SMP) should be initiated by the affecting States as appropriate. If smoke management policies are not required to meet 2018 goals, then States must include a brief discussion in their SIPs as to why a SMP is not required at this time. If States already have a SMP or other fire management policy in place, then they are advised by the EPA to mention their policies in the SIP, whether or not they will be used to meet 2018 goals (see EPA's "Interim Air Quality Policy on Wildland and Prescribed Fires," available online at http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf).

A primary objective of this document is to provide information on the impact of fires on haze in the MANE-VU region. Section 2 describes fires and smoke management in the MANE-VU region, section 3 provides information on the air quality impacts of smoke from wildland and prescribed fires, section 4 presents fire emissions inventory data, and section 5 summarizes relevant source apportionment results. While the contribution of fires to regional haze appears to be minor, fires may cause visibility problems on an episodic basis.

States are not required to include a SMP in their SIP. However, there are incentives for States to certify to the EPA that they have adopted and are implementing a basic SMP, whether or not the State chooses to incorporate the SMP into their SIP or make the SMP federally enforceable. Section 6 describes existing SMPs in the Region, provides an explanation of the incentives for States, and briefly explains the necessary elements in a basic SMP. Section 7 summarizes the key points presented in this paper.

2. Fires and Smoke Management in the MANE-VU Region

While some of the fires that occur in the MANE-VU Region are subject to SMPs, others are not. The definitions provided in this section are consistent with the descriptions included in the EPA's "Interim Air Quality Policy on Wildland and Prescribed Fires" (prepared in 1998 and available online at http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf), and the Western Regional Air Partnership's "Policy for Categorizing Fire Emissions" (prepared in 2001 and available online at www.fs.fed.us/pnw/fera/research/FirePolicy.pdf). Agricultural and forestry smoke management applies to all fires that are managed to achieve resource benefits, regardless of the cause of ignition (e.g. deliberate to meet specific objectives, lightning, arson, accidental, etc.) or the purpose of the fire (resource management, hazard reduction, etc.). Agricultural fires include all fires ignited by management actions to achieve benefits on agricultural land, such as croplands and pasture. Prescribed fires include all fires ignited by management techniques to achieve benefits on land other than agricultural land. Prescribed fires can be used for managing forests or rangeland, land on which the historic climax plant community is predominantly grasses, grass-like plants, forbs, or shrubs. Managed burning of logging debris, sometimes called slash burning, may also be used for forest management. Land managers may also manage naturally ignited fires to achieve resource benefits. While planning for naturally ignited fires is obviously limited, some land managers have plans to manage naturally ignited fires for specific objectives. These fires are sometimes referred to as "wildland fires managed for resource benefits" or "prescribed natural fires."

Naturally ignited fires in areas without plans for prescribed fires are considered unwanted fires or "wildfires" and are not covered by agricultural and forestry smoke management. Wildfires include any unwanted, non-structural fires that occur on wildlands, where there are a limited number of structures, or agricultural lands. Wildfires may be ignited by lightning, escaped prescribed fires, arson, or accidents, such as fireworks, cigarettes, escaped campfires, or vehicle fires, and are suppressed by management action. High pollutant concentrations attributable to wildfires can be treated as due to a natural event under EPA's Natural Events Policy. Under this policy, EPA may use its discretion not to redesignate areas as nonattainment if the State develops and implements a plan to respond to the health impacts of natural events.

Residential, industrial, and commercial/institutional wood combustion, open burning, slash burning, and structure fires are also not covered by SMPs. Residential industrial, and commercial/institutional wood combustion includes the burning of wood in indoor fireplaces and woodstoves and outdoor equipment. Open burning activities can occur at residential, commercial, or industrial sites and involve the burning of yard waste, including various types of plants and plant growth.

Emissions inventory results from 2002 (see section 4) show that the majority of fire emissions in the MANE-VU Region are from residential wood combustion. The Region is not prone to wildland fires due to vegetation types and relatively abundant rainfall. Agricultural and prescribed burning are also uncommon in the Region.

Typically, wood smoke is not detected in large amounts at monitoring sites in the MANE-VU Region. Several source apportionment studies that have been conducted in the MANE-VU Region show that wood smoke is a small to moderate contributor to fine particle pollution at monitoring sites (see section 5). Most source apportionment studies cannot distinguish between different types of fires, but smoke from agricultural and forestry activities is unlikely to be significant in the MANE-VU Region.

There are a few documented examples of wildfires producing large quantities of wood smoke and causing visibility impairment in MANE-VU Class I Areas. These fires have typically occurred outside the Region. For example, the July 7, 2002 Quebec Fires resulted in the largest one-day visibility impairment recorded at MANE-VU monitoring sites in recent years.

3. Air Quality and Visibility Impacts of Pollutants from Wildland and Prescribed Fires

Recent management strategies for some Federal, State, and Tribal wildlands involve increased use of wildland and prescribed fires to improve the health of the ecosystems and minimize risks to public and fire fighter safety. However, smoke from wildland and prescribed fires can contribute significantly to regional haze. To address issues associated with how fire managers can effectively use fires to help ecosystems while minimizing visibility impairment, the U.S. EPA, in partnership with other agencies, issued the "Interim Air Quality Policy on Wildland and Prescribed Fires," available on-line at http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf. The following description of air quality and visibility considerations includes information presented in this document. Other types of fires that involve vegetative burning (e.g. agricultural fires, open burning, residential wood combustion, etc.) have similar affects on air quality and visibility.

Burning wildland vegetation emits several air pollutants, including particles, NO_x, CO, and organic compounds. The quantity and composition of the emissions depend on the type of material burned, its moisture content, and the combustion temperature. Particle pollution from wildland and prescribed fires includes particles that have a diameter as large as 100 μm. Particles that have diameter less than 10 μm are referred to as PM_{10} and fine particles that have a diameter less than 2.5 μm are referred to as $PM_{2.5}$. There is evidence that particle pollution has serious health effects, particularly for sensitive populations.

Particle pollution also diminishes visibility because particles and gases scatter and absorb light. Fine particles scatter light more efficiently than coarser particles per unit mass. The fine particles that primarily contribute to visibility impairment include sulfates, nitrates, organic compounds, soot, and soil dust. As humidity increases, light scattering efficiencies also increase due to the adsorption of water on fine particles. Since the eastern United States typically has higher relative humidities than the West, the naturally occurring visual range in the East is only 105 to 190 km while the range in the West is 190 to 270 km. Visibility impairment affects the enjoyment of daily activities. Diminished visibility in mandatory Class I Federal areas, "Areas of Great Scenic Importance," is particularly important because haze affects the public's appreciation of scenic views and tourism.

4. MANE-VU Fire Emissions Inventories

4.1 Analysis of the 2002 MANE-VU Modeling Inventory

MANE-VU compiled a regional emissions inventory for 2002 for use in modeling. The inventory includes fire emissions from each State in the MANE-VU region. States provided fire emissions as annual county level estimates. Some States also provided estimates for seasonal and/or daily emissions, but those data are not shown here. Emissions data was collected for CO, NH_3, NO_x, $PM_{2.5}$, PM_{10}, SO_2, and VOC, but not all States provided data for all pollutants or source category codes (SCCs). Fire emissions include industrial wood combustion, commercial/institutional wood combustion, residential wood combustion, open burning, agricultural burning, forest fires, slash burning, prescribed burning, and structure fires.

The data presented here are from Version 2.0 of the MANE-VU Modeling Inventory, with updated residential wood combustion data from New York. Values for State emissions were calculated by adding the county level annual data. It should be noted that Version 3.0 of the MANE-VU Modeling Inventory is currently being developed. In Version 3.0 data will likely be added by States for certain fire emissions categories. The final version of this technical support document will include the data from Version 3.0 of the Inventory.

Massachusetts, New Hampshire, and Vermont provided data on industrial wood combustion (SCC 2102008000). Maine, Massachusetts, New Hampshire, and New York provided data on commercial/institutional wood combustion (SCC 2103008000).

All MANE-VU States and the District of Columbia provided data on residential wood combustion from indoor fireplaces and woodstoves. Connecticut, Delaware, Maine, Maryland, Massachusetts, and New Hampshire provided data for total woodstoves and fireplaces (SCC 2104008000). The District of Columbia, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states. Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, and New Hampshire have data for outdoor equipment (SCC 2104008070). There is no data in Version 2.0 for outdoor equipment from New Jersey, New York, Pennsylvania, Rhode Island, or Vermont.

All States except Connecticut reported data for open burning of yard waste leaf species (SCC 2610000100), yard waste brush species (SCC 2610000400), and household waste (SCC 2610030000). Connecticut, Delaware, Maryland, New Jersey, Pennsylvania, and Vermont included data for open burning of land clearing debris (SCC 2610000500). Only Pennsylvania reported data for industrial open burning (SCC 2610010000) and commercial/institutional open burning (SCC 2610020000). The District of Columbia did not report emissions for any of the open burning categories.

Maine, New Jersey, and Vermont provided emissions data on Agricultural Field Burning (SCC 2801500000), which involves whole fields set on fire and includes the burning of all crop types. No States in the MANE-VU region reported emissions from Agricultural Propaning (SCC 2801501000), which involves tractor-pulled burners being used to burn stubble only, or Agricultural Stack Burning (SCC 280150200), which involves straw stacks being moved from the field prior to burning.

All MANE-VU States provided some emissions data for forest (wildland) fires (SCC 2810001000). The District of Columbia did not report forest fire emissions for 2002. Maine and Maryland reported emissions data for managed/slash burning (SCC 2810005000), which often involves the burning of logging debris. Delaware, the District of Columbia, Maine, Maryland, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island included emissions data on prescribed burning for forest management (SCC 2810015000). Only Maine reported emissions from prescribed burning of rangeland (SCC 2810020000), and the amounts of all pollutants were negligible. All MANE-VU States and the District of Columbia provided emissions data for structure fires (SCC 2810030000).

Relative to other area sources, wood burning is a large source of CO, a moderate source of NO_x, PM_{10}, $PM_{2.5}$, and VOC, and a minor source of NH_3 and SO_2 in the MANE-VU Region. Emissions of CO, NH_3, NO_x, PM_{10}, $PM_{2.5}$, SO_2, and VOC in the MANE-VU Region by wood burning category are included in Table 1. The data for MANE-VU States and the District of Columbia that were used to calculate MANE-VU totals are included in tables in the appendix.

Table 1: Wood Smoke Emissions (Tons/Year) in the MANE-VU Region by source category (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Source Category	CO	NH_3	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Industrial Wood Comb.[1]	19,492	0	9,975	15,088	13,061	2,604	573
Comm./Inst. Wood Comb.[2]	5,055	0	1,655	659	567	35	50
Residential Wood Comb.[3]	918,005	5,310	11,253	121,163	115,357	1,734	542,428
Agricultural Burning[4]	3,030	0	54	208	161	0	363
Wildland Fires[5]	18,381	237	470	2,406	2,179	18	1,967
Managed/Slash Fires[6]	42	0	1	5	5	0	6
Prescribed Fires[7]	13,609	71	196	1,361	1,179	55	777
Structure Fires[8]	4,035	0	162	951	900	533	752
Open Burning[9]	189,504	152	7,069	24,597	23,713	428	17,174
All Fires	**1,171,154**	**5,771**	**30,835**	**166,439**	**157,122**	**5,407**	**564,090**

[1] SCC 2102008000; [2] SCC 2103008000; [3] SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4] SCC 2801500000; [5] SCC 2810001000; [6] SCC 2810005000; [7] SCC 2810015000 and SCC 2810020000; [8] SCC 2810030000; [9] SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

While emissions from wood burning activities comprise a significant portion of MANE-VU area source emissions, only a small portion of wood burning activities are relevant to agricultural and forestry smoke management. Agricultural, managed/slash, and prescribed burning are subject to SMPs. On rare occasions, forest (wildland) fires and structure fires that are permitted to burn are also covered by SMPs. Table 2 shows the sum of agricultural, managed/slash, prescribed, structure, and wildland fires, the total area source emissions, and the percentage of area emissions from wood burning for each pollutant.

Table 2: Wood Smoke Emissions (Tons/Year) in the MANE-VU Region by source category (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

MANE-VU	CO	NH_3	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Agricultural[1], Wildland[2], Managed/Slash[3], Prescribed[4], and Structure[5] Fires	39,098	308	884	4,932	4,424	606	3,865
Total Area Source Emissions[6]	1,661,601	246,769	254,843	1,502,247	440,075	311,167	1,879,510
% of Area Source Emissions	**2.35%**	**0.12%**	**0.35%**	**0.33%**	**1.01%**	**0.19%**	**0.21%**

[1]SCC 2801500000; [2]SCC 2810001000; [3]SCC 2810005000; [4]SCC 2810015000 and SCC 2810020000; [5]SCC 2810030000, [6]Data from the summary developed by E.H. Pechan and Associates, Inc. of area source emissions included in the 2002 MANE-VU Modeling Inventory, Version 2.0.

While fire emissions are not significant sources in any of the MANE-VU States or the District of Columbia, some States have slightly greater emissions than others. Figure 1 shows emissions from agricultural, managed/slash, prescribed, forest, and structure fires by State.

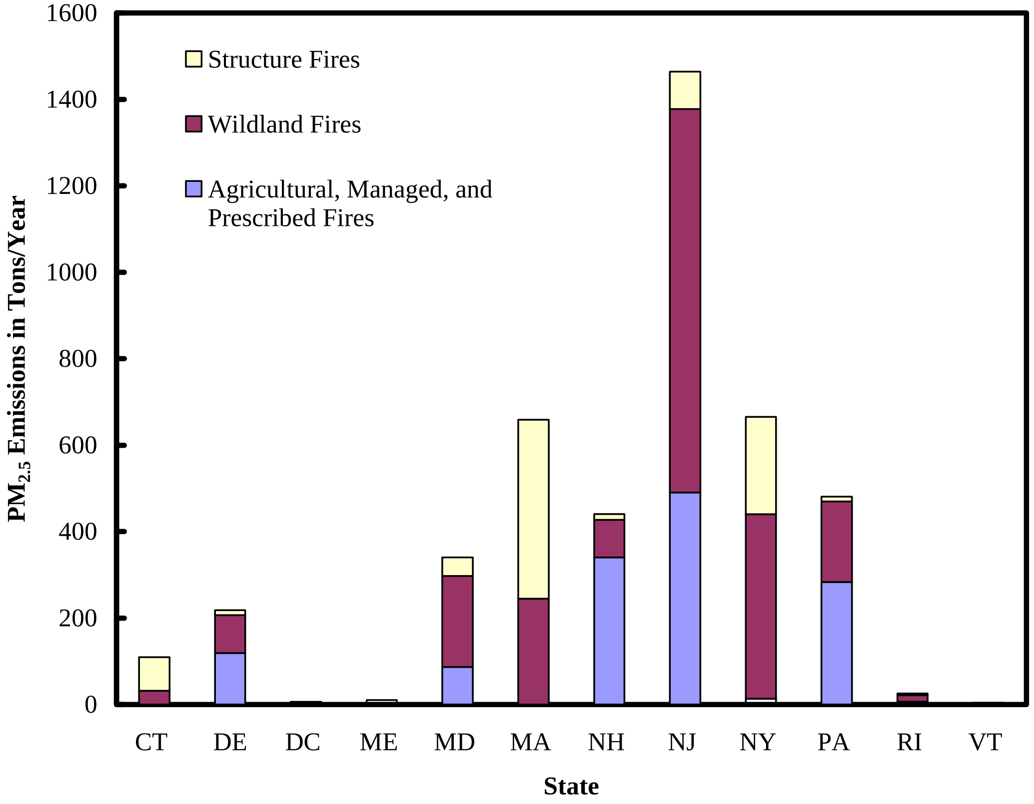

Figure 1: Fire emissions in the MANE-VU Region by state. (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Fires only account for approximately 2% of CO area source emissions, 1% of $PM_{2.5}$ area source emissions, and less than 1% of NH_3, NO_x, PM_{10}, SO_2, and VOC area source emissions in the MANE-VU Region. Considering that most forest and structure fires in the Region are unwanted “wildfires,” fires used for resource benefits are a very minor contributor to regional area source emissions.

Other sources of wood smoke are significantly larger sources of pollutants than fires used for resource benefits. Figure 2 shows the relative contributions of $PM_{2.5}$ emissions from the various wood burning source categories. The largest source categories for $PM_{2.5}$ are residential wood combustion (73.4%), open burning (15.1%), and industrial, commercial, and institutional wood combustion (8.7%). Structure fires and wildland fires, which are generally characterized as unwanted fires, only make up a minor portion of the wood burning emissions. Fires that are covered under SMPs, including fires due to agricultural, managed, and prescribed burning, comprise less than 1% of the total wood smoke emissions.

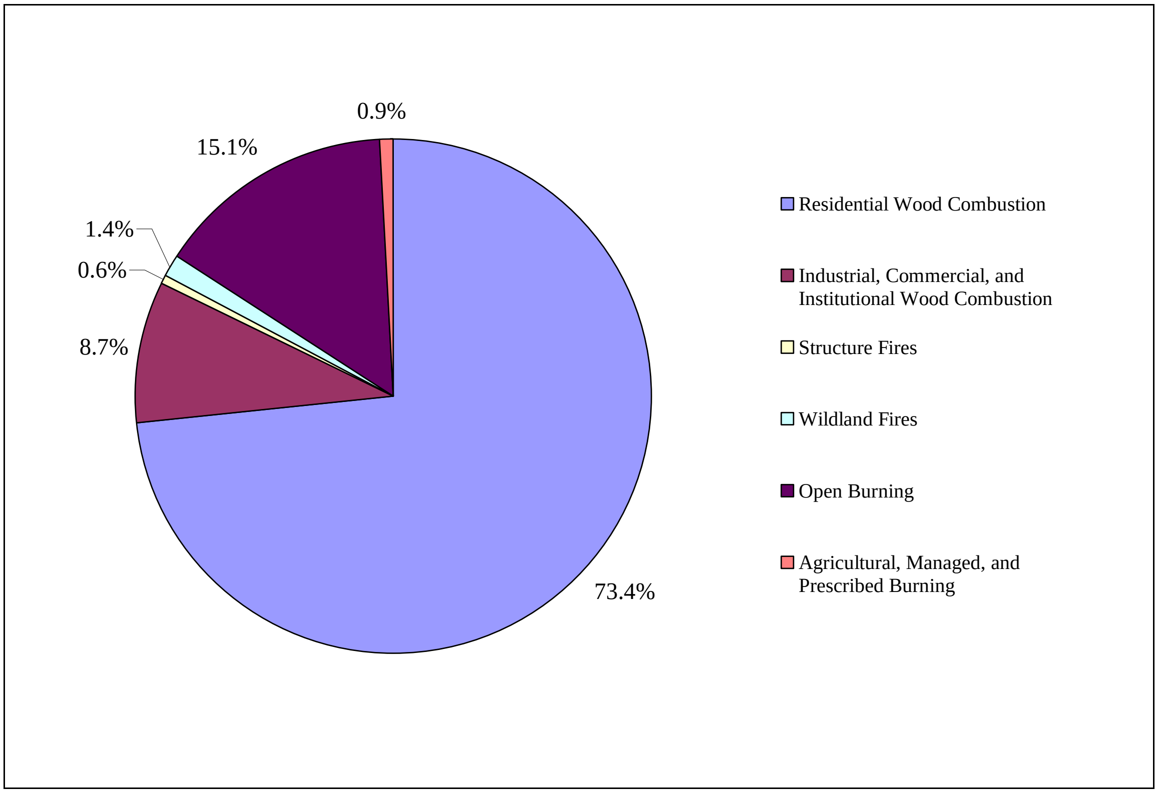

Figure 2: 2002 $PM_{2.5}$ Emissions from Wood Burning by Source Category (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated residential wood combustion data from New York)

4.2 Future Year Inventory Considerations

In setting reasonable progress goals and devising long term strategies, States must project the 2002 base year inventory to future years. When MANE-VU was developing future year emissions inventories, the National Park Service (NPS) and the United States Forest Service (USFS) were contacted to provide information on future burn plans. Information was not provided to MANE-VU in time, so the MANE-VU 2018 projection inventory holds fire emissions constant from 2002 through 2018.

4. Relevant MANE-VU Source Apportionment Study Results

States must include a contribution assessment and pollution apportionment analysis in their regional haze SIPs. MANE-VU is in the process of using a weight of evidence approach that relies on several methods for assessing the contribution of different emissions to regional haze at federal Class I areas. Preliminary findings of this work show that sulfate comprises one-half to two-thirds of $PM_{2.5}$ mass on the 20% haziest days and more than 40% of $PM_{2.5}$ mass on the 20% clearest days. Sulfates also have a much larger impact on visibility than the same mass of other pollutants. As a result, sulfates account for an even greater percentage of the particle–induced visibility impairment in the Region. The second most important contributor to $PM_{2.5}$ mass and also haze is organic carbon.

As part of the contribution assessment work, Serpil Kayin of MARAMA and Richard Poirot of the Vermont Department of Environmental Conservation summarized the results of studies that have used receptor-based models to apportion pollution sources at several sites within the Mid-Atlantic/Northeast Region and a few sites within the upwind or downwind influence area of the Region. The technical summary by Kayin and Poirot will appear as "Appendix B: Source Attribution by Receptor-Based Methods" in the MANE-VU document, *Tools and Techniques for Identifying Contributions to Regional Haze in the Northeast and Mid-Atlantic United States.* The most recent draft of Appendix B is available online at http://bronze.nescaum.org/Em/Haze-Contrib/AppendixB-04-07-05.pdf.

The primary goal of the receptor-based studies was to describe and quantify the major source categories that contribute to the observed $PM_{2.5}$ concentrations. Several methods were used to apportion $PM_{2.5}$ concentrations including mathematical receptor models and ensemble trajectory analysis techniques. Descriptions of the monitoring sites that were investigated by Kayin and Poirot are included in Table 3. For more information on the periods of data collection, analysis technique(s), and references, see the draft of "Appendix B: Source Apportionment by Receptor-Based Methods."

Table 3: Monitoring sites in the MANE-VU Region where source apportionment analyses have been conducted

Site	Location	Elevation (meters)	Type of Monitoring Network
Acadia National Park, ME	44 N, 68 W	150	IMPROVE
Lye Brook Wilderness, VT	43 N, 73 W	1010	IMPROVE
Underhill, VT	45 N, 73 W	400	IMPROVE
New York, NY (three sites in the Bronx, one site in Queens)	41 N, 74 W		Urban STN
Brigantine Wilderness, NJ	39 N, 74 W	15	IMPROVE
Baltimore-Washington Corridor (Fort Meade, MD)	39 N, 77 W	46	Site included in a University of Maryland study
Washington, DC	39 N, 77 W	30	McMillan IMPROVE
Shenandoah National Park, VA	39 N, 78 W	1098	IMPROVE
Jefferson/James River Face Wilderness Area, VA	38 N, 79 W	280	IMPROVE
Dolly Sodds Wilderness Area, WV	39 N, 79 W	1158	IMPROVE
Mammoth Cave National Park, KY	37 N, 86 W	248	IMPROVE
Great Smoky Mountains National Park, TN	36 N, 84 W	815	IMPROVE
Boundary Waters canoe area, MN	48 N, 91 W	524	IMPROVE
Charlotte, NC	35 N, 81 W	230	EPA Trends
Boston, MA (residential site in Watertown, MA)	42 N, 71 W		Site included in the Harvard Six Cities Study
Potsdam and Stockton, NY (one Potsdam site, one Stockton site)	47 N, 75 W 42 N, 79 W		Site included in a Clarkson University study
Toronto, Canada			Site located at the University of Toronto

The data presented in the report by Kayin and Poirot are source apportioned $PM_{2.5}$ mass and the percentage of $PM_{2.5}$ mass. While the sources for $PM_{2.5}$ and haze are the same, the relative importance of those sources on $PM_{2.5}$ concentration and visibility impairment differ somewhat. In addition to being related to $PM_{2.5}$ concentration, light extinction is also a function of the components of $PM_{2.5}$ and relative humidity. Thus, while source apportioned $PM_{2.5}$ mass data is highly relevant to regional haze, there are limitations to making direct comparisons. Certain pollutants, such as sulfate, make up a larger contribution to regional haze than to $PM_{2.5}$ mass.

The major sources of $PM_{2.5}$ identified were coal burning (primary and secondary sulfate aerosols), secondary organic matter from possibly mobile sources, nitrate aerosols, biomass burning (wood smoke and forest fires indicated by the presence of organic carbon, elemental carbon, and potassium), industrial sources (a variety of sources, including smelters, incinerators, and oil burning, indicated by the presence of elemental carbon and characteristic trace metals), a crustal source (dust and soil indicated by the presence of silicon, aluminum, calcium, iron, and titanium), and a sea salt source (identified by the presence of sodium and chloride).

A wood smoke or biomass burning source was identified at most of the rural sites, but was generally not detected or of small magnitude in larger urban areas, including Boston, New York City, Toronto, and Washington D.C. Wood smoke was also a negligible or low contributor (less than 10%) in Acadia National Park, Boundary Waters, Brigantine Wilderness, Charlotte, Dolly Sods Wilderness Area, Great Smoky Mountains National Park, and Potsdam and Stockton.

Wood smoke was identified as a significant source of average $PM_{2.5}$ mass (greater than 10%) in the Baltimore-Washington corridor, Lye Brook Wilderness, Mammoth Cave National Park, Shenandoah National Park, Jefferson/James River Face Wilderness Area, and Underhill. In Lye Brook Wilderness and Underhill, wood smoke was the second largest source, following regional secondary sulfate.

In the Lye Brook Wilderness Area, wood smoke comprised a relatively high percentage (35%) of the average $PM_{2.5}$ mass. However, the smoke source was not identified as especially important there on either the 20% best or worst visibility days.

Smoke also contributed significantly to the $PM_{2.5}$ mass at Underhill, VT. This source was found to make up a large portion (25%) of the $PM_{2.5}$ mass on the 20% clearest days but a smaller portion (7%) on the 20% dirtiest days. It was predicted that the site was influenced by Canadian fires.

In addition studies on source categories, there has also been work to investigate the source regions for wood smoke. Figure 3 is based on source apportionment and back trajectory results in the Eastern United States. The results for various IMPROVE sites are aggregated for the Northeast Region (Acadia National Park, Presidential Mountain Range, and Lye Brook Wilderness Area), the Mid-Atlantic Region (Washington D.C., Shenandoah National Park, and James River Face Wilderness Area), and the Southeast Region (Great Smoky Mountains National Park and Mammoth Cave National Park).

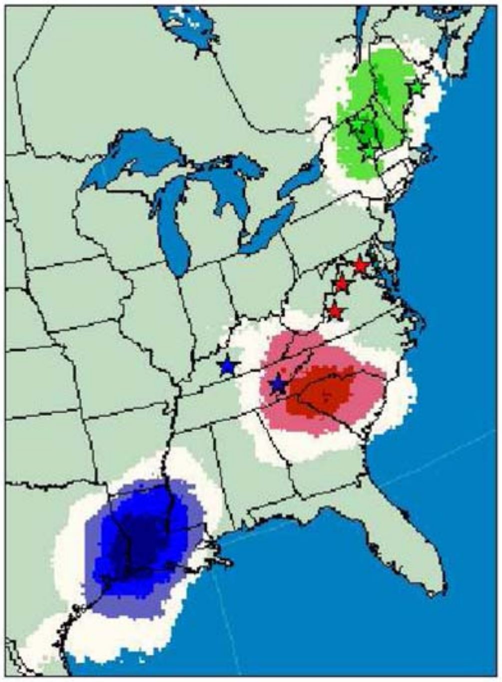

Figure 3: Wood smoke source regional aggregations (Source "Appendix B: Source Attribution by Receptor-Based Methods" in the MANE-VU document, *Tools and Techniques for Identifying Contributions to Regional Haze in the Northeast and Mid-Atlantic United States.* The most recent draft of Appendix B is available online at http://bronze.nescaum.org/Em/Haze-Contrib/AppendixB-04-07-05.pdf.) The results are aggregated for New England in green (Acadia National Park, Presidential Mountain Range, and Lye Brook Wilderness Area), the Mid-Atlantic in red (Washington D.C., Shenandoah National Park, and James River Face Wilderness Area), and the Southeast in blue (Great Smoky Mountains National Park and Mammoth Cave National Park).

The results shown in the figure demonstrate that in the Northeast wood smoke emissions are local, indicating that the smoke is mostly from residential wood combustion. However, in the Mid-Atlantic and Southeast Regions, the source regions for the wood smoke lie far from the monitoring sites, showing the probable influence of fires to the south.

Although source apportionment studies have not been conducted at all the Class I Areas in the MANE-VU Region, it is reasonable to conclude that throughout the Region, wood smoke is a small to moderate contributor to average fine mass. There are other general statements conclusions made in "Appendix B: Source Attribution by Receptor-Based Methods." In general, contributions are higher in rural areas than urban areas. There are also winter peaks in northern areas from residential wood burning, and occasional summer impacts from wildfires.

Although wood smoke is typically not a large contributor to $PM_{2.5}$ mass, there are exceptions, generally involving wildfires. A notable exception occurred on July 7, 2002. This event affected urban and rural sites and resulted in the largest one-day regional fine mass concentrations and visibility impacts recorded in recent years.

5. Smoke Management Programs in the MANE-VU Region

MARAMA, on behalf of MANE-VU, sent out a smoke management plan questionnaire to MANE-VU States and tribes in August 2004. The District of Columbia, Delaware, Maine, Maryland, New York, the Penobscot Indian Nation, the St. Regis Mohawk Tribe, and Vermont responded to the survey. All five states and the District of Columbia have the legal authority to allow or prohibit burning. Delaware, Maine, Maryland, and New York have a formal permitting system in place. Vermont has a SMP that applies to the nuisance of smoke. In 2004, Maine was in the development phase of a SMP being devised by the state forest service. States that do have a process for approving burns may choose to reference their program in the Regional Haze SIP as advised by the EPA.

There are incentives for States to adopt a SMP. The following statement is included in the "Interim Air Quality Policy on Wildland and Prescribed Fires," issued by the US EPA on April 23, 1998 (http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf).

> *If a certified SMP has not been implemented, EPA will not give special consideration to the high PM concentrations attributed to fires managed for resource benefits that cause or significantly contribute to: (1) violations of $PM_{2.5}$ or PM_{10} NAAQS, (2) visibility impairment in mandatory Class I Areas, or (3) failure to achieve reasonable progress toward the national visibility goal. Rather, EPA will call for adoption of the basic SMP, described in section IV of the Interim policy as part of the SIP/TIP for PM and visibility. The EPA will also notify the governor of the State or the tribal government that the area should be redesignated as nonattainment.*

The EPA also states in the Interim Policy that if State/tribal air quality managers certify in a letter to the EPA that at least a basic SMP has been adopted and implemented, "special consideration will be given under this policy to air quality data resulting from fires managed for resource benefits. When PM concentrations are attributable to wildfires that are treated under the Natural Events Policy, the EPA will "exercise its discretion, under section 107(d)(3) of the CAA, not to redesignate areas as nonattainment if the State develops and implements a plan to respond to the health impacts of natural events."

If States choose to adopt a SMP to protect the State from the future possibility of begin re-designated as non-attainment, there are several elements that should be included. These elements are described in EPA's "Interim Air Quality Policy on Wildland and Prescribed Fires," available on-line at http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf.

7. Summary

Smoke Management Programs are only required when smoke impacts from fires managed for resource benefits contribute significantly to regional haze. The results of the emissions inventory indicate that emissions from agricultural, managed, and prescribed burning are very minor source categories. Although source apportionment results show that wood smoke is a moderate contributor to visibility impairment at some Class I Areas in the MANE-VU Region, most of the wood smoke is attributable to residential wood combustion. It is unlikely that fires for agricultural or forestry management cause large impacts on visibility in any of the Class I Areas in the MANE-VU Region. On rare occasions, smoke from major fires degrades the air quality and visibility in the MANE-VU Area. However, these fires are generally unwanted wildfires that are not subject to SMPs.

Table X: Carbon Monoxide Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]						12,780.00	6,439.02					273.27	19,492.29
Comm./Inst. Wood Comb.[2]				398.40		414.30	125.30		4,117.03				5,055.03
Residential Wood Comb.[3]	65,252.83	9,108.60	1,141.55	99,653.19	61,174.59	104,461.99	63,713.43	70,620.56	334,864.80	74,914.96	2,690.71	30,407.56	918,004.75
Agricultural Burning[4]				1,368.00				1,661.76					3,029.76
Wildland Fires[5]	384.33	1,054.03		0.07	1,729.92	2,018.50	1,042.96	4,599.13	5,120.12	2,234.03	175.36	22.81	18,381.28
Managed/Slash Fires[6]				0.15	42.00								42.15
Prescribed Fires[7]		1,430.59	0.05	0.03	456.99		4,084.07	4,005.12	155.81	3,396.93	79.81		13,609.39
Structure Fires[8]	471.80	66.71	37.09	49.62	263.72	414.21	79.16	481.69	1,377.72	765.92	1.59	25.71	4,034.92
Open Burning[9]	243.96	998.36	0.00	6,318.23	70,978.49	2,418.51	1,895.67	170.03	8,003.64	86,714.58	294.93	11,467.75	189,504.16
All Fires	**66,108.96**	**11,659.92**	**1,178.69**	**101,469.46**	**63,667.22**	**120,088.99**	**75,483.94**	**81,368.25**	**345,635.49**	**81,311.83**	**2,947.47**	**30,729.35**	**981,649.57**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: Carbon Monoxide Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						12,780.00	6,439.02					273.27	19,492.29
2103008000				398.40		414.30	125.30		4,117.03				5,055.03
Indoor RWC[1]	61,903.34	8,290.40	605.51	97,150.23	56,108.05	98,315.64	61,753.56	70,620.56	334,864.80	74,914.96	2,690.71	30,407.56	897,625.32
2104008070	3,349.49	818.19	536.04	2,502.95	5,066.54	6,146.34	1,959.87						20,379.43
2801500000				1,368.00				1,661.76					3,029.76
2810001000	384.33	1,054.03		0.07	1,729.92	2,018.50	1,042.96	4,599.13	5,120.12	2,234.03	175.36	22.81	18,381.28
2810005000				0.15	42.00								42.15
2810015000		1,430.59	0.05	0.01	456.99		4,084.07	4,005.12	155.81	3,396.93	79.81		13,609.37
2810020000				0.02									0.02
2810030000	471.80	66.71	37.09	49.62	263.72	414.21	79.16	481.69	1,377.72	765.92	1.59	25.71	4,034.92
2610000100		22.29		293.77	437.37	69.12	1,002.53	60.28	1,290.94	1,743.11	7.35	635.15	5,561.90
2610000400		107.44		367.21	2,886.22	1,284.14	250.60	19.47	1,627.32	2,288.83	9.18	793.94	9,634.36
2610000500	243.96	739.49			66,601.11					69,750.94		9,240.48	146,575.98
2610010000										981.79			981.79
2610020000										2,516.36			2,516.36
2610030000		129.14		5,657.25	1,053.80	16.31	150.96	90.28	5,085.38	9,433.55	278.40	439.68	22,334.75
2610040400						1048.937	491.580					358.502	1,899.02
All Fires	**66,352.91**	**12,658.28**	**1,178.69**	**107,787.70**	**134,645.71**	**122,507.51**	**77,379.61**	**81,538.29**	**353,639.13**	**168,026.41**	**3,242.40**	**42,197.10**	**1,171,153.73**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: Ammonia Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]													0.00
Comm./Inst. Wood Comb.[2]													0.00
Residential Wood Comb.[3]	470.35	65.67	3.82	719.35	441.14	752.72	459.64	2,397.60					5,310.29
Agricultural Burning[4]													0.00
Wildland Fires[5]	1.73	4.74				47.73	4.69	127.40	50.26		0.79	0.09	237.43
Managed/Slash Fires[6]													0.00
Prescribed Fires[7]		6.42		0.51			18.37	6.92		15.28	0.36	22.96	70.82
Structure Fires[8]													0.00
Open Burning[9]		1.22			40.34	12.34	11.28		29.17	40.21		17.52	152.07
All Fires	**472.07**	**78.04**	**3.82**	**719.86**	**481.48**	**812.79**	**493.99**	**2,531.92**	**79.43**	**55.49**	**1.15**	**40.57**	**5,770.61**

[1] SCC 2102008000; [2] SCC 2103008000; [3] SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4] SCC 2801500000; [5] SCC 2810001000; [6] SCC 2810005000; [7] SCC 2810015000 and SCC 2810020000; [8] SCC 2810030000; [9] SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: Ammonia Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000													0.00
2103008000													0.00
Indoor RWC[1]	446.48	59.84		701.52	405.04	708.92	445.68	2397.60					5,165.07
2104008070	23.87	5.83	3.82	17.84	36.10	43.80	13.97						145.22
2801500000													0.00
2810001000	1.73	4.74				47.73	4.69	127.40	50.26		0.79	0.09	237.43
2810005000													0.00
2810015000		6.42		0.51			18.37	6.92		15.28	0.36	22.96	70.82
2810020000													0.00
2810030000													0.00
2610000100		0.25			4.92	0.78	11.28		14.52	19.61		7.15	58.51
2610000400		0.97			25.98	11.57			14.65	20.60		7.15	80.90
2610000500													0.00
2610010000													0.00
2610020000													0.00
2610030000													0.00
2610040400					9.44							3.23	12.67
FIRES	**472.07**	**78.04**	**3.82**	**719.86**	**481.48**	**812.79**	**493.99**	**2531.92**	**79.43**	**55.49**	**1.15**	**40.57**	**5,770.61**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: Nitrogen Oxides Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]	0.00	0.00	0.00	0.00	0.00	4,686.10	5,258.55	0.00	0.00	0.00	0.00	30.17	9,974.82
Comm./Inst. Wood Comb.[2]	0.00	0.00	0.00	1,206.40	0.00	197.90	102.33	0.00	148.33	0.00	0.00	0.00	1,654.96
Residential Wood Comb.[3]	821.26	120.19	13.25	1,265.06	751.16	1,331.80	815.04	856.75	3,929.40	929.66	34.37	384.73	11,252.67
Agricultural Burning[4]	0.00	0.00	0.00	54.00	0.00	0.00	0.00	0.18	0.00	0.00	0.00	0.00	54.18
Wildland Fires[5]	8.25	22.60	0.00	0.44	49.43	57.20	22.37	131.40	109.84	63.83	3.76	0.49	469.62
Managed/Slash Fires[6]	0.00	0.00	0.00	0.00	1.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.20
Prescribed Fires[7]	0.00	30.65	0.00	0.00	0.00	0.00	87.62	0.00	3.34	72.88	1.71	0.00	196.20
Structure Fires[8]	11.01	1.56	0.87	1.16	6.15	9.66	1.85	11.24	32.15	17.87	68.35	0.60	162.46
Open Burning[9]	6.58	36.06	0.00	399.34	2,402.02	88.29	83.71	10.40	488.20	3,154.06	19.65	380.75	7,069.06
All Fires	**847.10**	**211.06**	**14.12**	**2,926.39**	**3,209.97**	**6,370.95**	**6,371.47**	**1,009.97**	**4,711.27**	**4,238.30**	**127.85**	**796.74**	**30,835.17**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: Nitrogen Oxides Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						4686.10	5258.55					30.17	9,974.82
2103008000				1206.40		197.90	102.33		148.33				1,654.96
Indoor RWC[1]	786.79	111.77	7.73	1239.29	699.01	1268.54	794.87	856.75	3929.40	929.66	34.37	384.73	11,042.91
2104008070	34.48	8.42	5.52	25.76	52.15	63.26	20.17						209.76
2801500000				54.00				0.18					54.18
2810001000	8.25	22.60		0.44	49.43	57.20	22.37	131.40	109.84	63.83	3.76	0.49	469.62
2810005000				0.00	1.2								1.20
2810015000		30.65	0.00	0.00			87.62		3.34	72.88	1.71		196.20
2810020000				0.00									0.00
2810030000	11.01	1.56	0.87	1.16	6.15	9.66	1.85	11.24	32.15	17.87	68.35	0.60	162.46
2610000100		1.23			24.21	3.83	55.51	3.34	71.46	96.49		35.16	291.23
2610000400		3.84			103.08	45.85		0.70	58.12	81.74		28.35	321.68
2610000500	6.58	21.88			2200.42					2063.64		273.39	4,565.90
2610010000										69.30			69.30
2610020000										177.63			177.63
2610030000		9.11		399.34	74.31	1.15	10.64	6.37	358.62	665.26	19.65	31.04	1,575.48
2610040400						37.46	17.56					12.80	67.83
FIRES	**847.10**	**211.06**	**14.12**	**2926.39**	**3209.97**	**6370.95**	**6371.47**	**1009.97**	**4711.27**	**4238.30**	**127.85**	**796.74**	**30,835.17**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: PM$_{10}$ Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]	0.00	0.00	0.00	0.00	0.00	11,012.10	4,045.85	0.00	0.00	0.00	0.00	30.28	15,088.23
Comm./Inst. Wood Comb.[2]	0.00	0.00	0.00	0.00	0.00	465.30	78.73	0.00	115.03	0.00	0.00	0.00	659.06
Residential Wood Comb.[3]	8,520.69	1,227.88	157.87	12,569.57	8,194.29	13,689.27	8,019.21	9,363.04	44,821.80	10,285.66	375.25	3,938.41	121,162.93
Agricultural Burning[4]	0.00	0.00	0.00	2.15	0.00	0.00	0.00	203.61	0.00	0.00	0.00	2.14	207.90
Wildland Fires[5]	37.37	102.57	0.00	0.04	210.06	244.90	101.41	985.53	497.84	207.45	17.05	2.22	2,406.44
Managed/Slash Fires[6]	0.00	0.00	0.00	0.01	5.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.11
Prescribed Fires[7]	0.00	139.21	0.01	0.00	82.02	0.00	397.10	389.93	15.15	330.29	7.76	0.00	1,361.47
Structure Fires[8]	0.00	0.00	0.00	94.49	47.47	13.66	430.72	277.14	87.40	0.00	0.00	0.00	950.89
Open Burning[9]	30.79	122.27	0.00	2,673.38	8,205.49	345.94	329.81	34.42	1,599.93	9,753.43	128.07	1,373.52	24,597.06
All Fires	**8,588.85**	**1,591.94**	**157.87**	**15,339.66**	**16,744.44**	**25,771.17**	**13,402.83**	**11,253.66**	**47,137.16**	**20,576.83**	**528.13**	**5,346.57**	**166,439.10**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: PM$_{10}$ Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						11,012.10	4,045.85					30.28	15,088.23
2103008000						465.30	78.73		115.03				659.06
Indoor RWC[1]	8,061.89	1,115.81	84.44	12,226.73	7,500.30	12,847.37	7,750.75	9,363.04	44,821.80	10,285.66	375.25	3,938.41	118,371.45
2104008070	458.80	112.07	73.42	342.84	693.99	841.90	268.45						2,791.48
2801500000				2.15				203.61				2.14	207.90
2810001000	37.37	102.57		0.04	210.06	244.90	101.41	985.53	497.84	207.45	17.05	2.22	2,406.44
2810005000				0.01	5.10								5.11
2810015000		139.21	0.01	0.00	82.02		397.10	389.93	15.15	330.29	7.76		1,361.47
2810020000				0.00									0.00
2810030000				94.49	47.47	13.66	430.72	277.14	87.40				950.89
2610000100		4.38		99.67	85.91	13.58	196.94	11.84	253.58	342.40	2.49	124.76	1,135.55
2610000400		15.14		44.59	406.75	180.95	30.43	2.74	229.34	322.56	1.12	111.89	1,345.51
2610000500	30.79	74.39			7,481.36					7,016.37		929.52	15,532.42
2610010000													0.00
2610020000													0.00
2610030000		28.37		2,529.12	231.47	3.58	33.16	19.83	1,117.02	2,072.11	124.46	156.83	6,315.95
2610040400						147.83	69.28					50.52	267.63
FIRES	**8,588.85**	**1,591.94**	**157.87**	**15,339.66**	**16,744.44**	**25,771.17**	**13,402.83**	**11,253.66**	**47,137.16**	**20,576.83**	**528.13**	**5,346.57**	**166,439.10**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: $PM_{2.5}$ Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]	0.00	0.00	0.00	0.00	0.00	9,521.10	3,509.28	0.00	0.00	0.00	0.00	30.28	13,060.66
Comm./Inst. Wood Comb.[2]	0.00	0.00	0.00	0.00	0.00	402.30	68.28	0.00	96.57	0.00	0.00	0.00	567.15
Residential Wood Comb.[3]	8,520.69	1,227.88	157.87	12,569.57	8,194.29	13,689.27	8,019.21	9,363.04	39,291.34	10,285.66	375.25	3,662.72	115,356.78
Agricultural Burning[4]	0.00	0.00	0.00	2.15	0.00	0.00	0.00	156.30	0.00	0.00	0.00	2.14	160.59
Wildland Fires[5]	32.05	87.93	0.00	0.04	210.06	244.90	86.97	886.98	426.97	186.70	14.62	1.90	2,179.12
Managed/Slash Fires[6]	0.00	0.00	0.00	0.01	5.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.11
Prescribed Fires[7]	0.00	118.98	0.00	0.00	82.02	0.00	340.57	334.22	12.99	283.27	6.66	0.00	1,178.74
Structure Fires[8]	77.28	10.93	6.08	8.13	43.20	414.20	12.98	86.70	225.67	11.01	4.21	0.00	900.39
Open Burning[9]	30.79	116.41	0.00	9,935.62	617.61	270.29	309.62	33.64	1,453.33	9,505.04	117.59	1,323.10	23,713.04
All Fires	**8,660.81**	**1,562.13**	**163.95**	**22,515.52**	**9,152.28**	**24,542.07**	**12,346.91**	**10,860.88**	**41,506.87**	**20,271.68**	**518.32**	**5,020.14**	157,121.58

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: $PM_{2.5}$ Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						9521.10	3509.28					30.28	13,060.66
2103008000						402.30	68.28		96.57				567.15
Indoor RWC[1]	8061.89	1115.81	84.44	12226.73	7500.30	12847.37	7750.75	9363.04	39291.34	10285.66	375.25	3662.72	112,565.30
2104008070	458.80	112.07	73.42	342.84	693.99	841.90	268.45						2,791.48
2801500000				2.15				156.30				2.14	160.59
2810001000	32.05	87.93		0.04	210.06	244.90	86.97	886.98	426.97	186.70	14.62	1.90	2,179.12
2810005000				0.01	5.10								5.11
2810015000		118.98	0.00	0.00	82.02		340.57	334.22	12.99	283.27	6.66		1,178.73
2810020000				0.00									0.00
2810030000	77.28	10.93	6.08	8.13	43.20	414.20	12.98	86.70	225.67	11.01	4.21		900.39
2610000100		4.38		99.67	85.91	13.58	196.94	11.84	253.58	342.40	2.49	124.76	1,135.55
2610000400		11.67		38.44	319.72	139.48	28.91	3.64	176.80	248.67	1.12	86.26	1,054.68
2610000500	30.79	74.39		7481.36						7016.37		929.52	15,532.42
2610010000													0.00
2610020000													0.00
2610030000		25.98		2316.14	211.98	3.28	30.36	18.16	1022.95	1897.62	113.98	143.62	5,784.07
2610040400						113.96	53.41					38.95	206.32
FIRES	**8660.81**	**1562.13**	**163.95**	**22515.52**	**9152.28**	**24428.11**	**12293.50**	**10860.88**	**41506.87**	**20271.68**	**518.32**	**4981.19**	**157,121.58**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: Sulfur Dioxide Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Source Category	**CT**	**DE**	**DC**	**ME**	**MD**	**MA**	**NH**	**NJ**	**NY**	**PA**	**RI**	**VT**	**TOTAL**
Industrial Wood Comb.[1]	0.00	0.00	0.00	0.00	0.00	532.50	268.30	0.00	0.00	0.00	0.00	1,803.37	2,604.17
Comm./Inst. Wood Comb.[2]	0.00	0.00	0.00	0.00	0.00	22.40	5.24	0.00	7.57	0.00	0.00	0.00	35.21
Residential Wood Comb.[3]	120.13	16.07	2.03	184.00	107.05	193.51	119.02	122.39	666.00	141.97	5.25	56.34	1,733.77
Agricultural Burning[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.18
Wildland Fires[5]	2.26	6.20	0.00	0.00	0.00	0.00	6.14	0.00	0.00	2.39	0.00	1.03	18.02
Managed/Slash Fires[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Prescribed Fires[7]	0.00	8.40	0.00	1.60	0.00	0.00	24.02	0.00	0.92	19.98	0.47	0.00	55.39
Structure Fires[8]	0.00	0.00	0.00	0.00	0.00	532.50	0.00	0.00	0.00	0.00	0.00	0.00	532.50
Open Burning[9]	0.00	2.95	0.00	66.56	49.62	28.23	14.40	1.70	88.02	150.21	3.28	23.14	428.11
All Fires	**122.39**	**33.62**	**2.03**	**252.15**	**156.66**	**1,309.14**	**437.12**	**124.28**	**762.51**	**314.55**	**9.00**	**1,883.89**	5,407.34

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: Sulfur Dioxide Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

SCC	**CT**	**DE**	**DC**	**ME**	**MD**	**MA**	**NH**	**NJ**	**NY**	**PA**	**RI**	**VT**	**TOTAL**
2102008000						532.50	268.30					1803.37	2604.17
2103008000						22.40	5.24		7.57				35.21
Indoor RWC[1]	114.83	14.78	1.18	180.04	99.02	183.77	115.92	122.39	666.00	141.97	5.25	56.34	1701.49
2104008070	5.30	1.30	0.85	3.96	8.02	9.73	3.10						32.27
2801500000								0.18					0.18
2810001000	2.26	6.20				0.00	6.14	0.00		2.39		1.03	18.02
2810005000													0.00
2810015000		8.40	0.00	1.60			24.02	0.00	0.92	19.98	0.47		55.39
2810020000													0.00
2810030000						532.50		0.00					532.50
2610000100		0.15			2.97	0.47	6.80	0.41	8.76	11.83		4.31	35.70
2610000400		1.27			34.22	15.13		0.23	19.30	27.14		9.41	106.71
2610000500													0.00
2610010000													0.00
2610020000													0.00
2610030000		1.52		66.56	12.43	0.19	1.77	1.06	59.97	111.24	3.28	5.17	263.18
2610040400						12.44	5.83					4.25	22.52
FIRES	**122.39**	**33.62**	**2.03**	**252.15**	**156.66**	**1309.14**	**437.12**	**124.28**	**762.51**	**314.55**	**9.00**	**1883.89**	**5407.34**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: VOC Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]	0.00	0.00	0.00	0.00	0.00	362.10	182.44	0.00	0.00	0.00	0.00	28.14	572.68
Comm./Inst. Wood Comb.[2]	0.00	0.00	0.00	27.31	0.00	15.31	3.55	0.00	3.94	0.00	0.00	0.00	50.11
Residential Wood Comb.[3]	41,067.78	5,952.16	732.81	59,815.62	39,433.79	66,217.39	38,651.94	16,217.03	237,762.00	25,537.32	1,096.92	9,943.74	542,428.48
Agricultural Burning[4]	0.00	0.00	0.00	128.40	0.00	0.00	0.00	235.00	0.00	0.00	0.00	0.00	363.40
Wildland Fires[5]	18.09	49.55	0.00	0.01	92.90	345.40	49.08	778.57	240.95	382.98	8.25	1.08	1,966.85
Managed/Slash Fires[6]	0.00	0.00	0.00	0.03	5.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.73
Prescribed Fires[7]	0.00	67.38	0.00	0.01	70.31	0.00	192.19	275.73	7.33	159.86	3.76	0.00	776.56
Structure Fires[8]	86.50	12.23	6.80	9.10	48.35	76.00	14.51	88.31	252.58	140.42	12.53	4.71	752.03
Open Burning[9]	20.00	77.30	0.00	2,119.95	5,266.93	192.34	358.82	22.18	795.09	7,235.23	101.34	985.08	17,174.26
All Fires	**41,192.36**	**6,158.62**	**739.61**	**62,100.43**	**44,917.97**	**67,208.53**	**39,452.53**	**17,616.82**	**239,061.89**	**33,455.80**	**1,222.80**	**10,962.75**	**564,090.10**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: VOC Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 2.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						362.10	182.44					28.14	572.68
2103008000				27.31		15.31	3.55		3.94				50.11
Indoor RWC[1]	38,031.23	5,210.41	246.85	57,546.51	34,840.60	60,645.29	36,875.18	16,217.03	237,762.00	25,537.32	1,096.92	9,943.74	523,953.07
2104008070	3,036.55	741.75	485.96	2,269.11	4,593.18	5,572.10	1,776.76						18,475.41
2801500000				128.40				235.00					363.40
2810001000	18.09	49.55		0.01	92.90	345.40	49.08	778.57	240.95	382.98	8.25	1.08	1,966.85
2810005000				0.03	5.70								5.73
2810015000		67.38	0.00	0.00	70.31		192.19	275.73	7.33	159.86	3.76		776.56
2810020000				0.00									0.00
2810030000	86.50	12.23	6.80	9.10	48.35	76.00	14.51	88.31	252.58	140.42	12.53	4.71	752.03
2610000100		5.57		73.44	109.34	17.28	250.63	15.07	322.73	435.78	1.84	158.79	1,390.47
2610000400		14.58		49.84	391.70	174.25	34.01	2.64	220.85	310.63	1.25	107.75	1,307.49
2610000500	20.00	50.76			4,571.41					4,787.64		634.26	10,064.07
2610010000										346.51			346.51
2610020000										888.13			888.13
2610030000		6.39		1,996.68	52.12	0.81	7.47	4.47	251.51	466.55	98.26	35.63	2,919.87
2610040400					142.36		66.71					48.65	257.72
FIRES	**41,192.36**	**6,158.62**	**739.61**	**62,100.43**	**44,917.97**	**67,208.53**	**39,452.53**	**17,616.82**	**239,061.89**	**33,455.80**	**1,222.80**	**10,962.75**	**564,090.10**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

FINAL

Assessment of Reasonable Progress for Regional Haze In MANE-VU Class I Areas

Methodology for Source Selection, Evaluation of Control Options, and Four Factor Analysis

Prepared for:

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List of Acronyms

AFGD	Advanced Flue Gas Desulfurization
BACM	Best Available Control Measure
BART	Best Available Retrofit Technology
BLM	Bureau of Land Management
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
CO_2	carbon dioxide
DOE	Department of Energy
EGU	Electric Generating Unit
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
HAP	Hazardous Air Pollutant
ICI	Industrial, Commercial, Institutional
IPM®	Integrated Planning Model
kW	kilowatt
kWh	kilowatt-hour
LADCO	Lake Michigan Air Directors Consortium
LAER	Lowest Achievable Emission Rate
LNB	Low NO_X Burner
LSD	Lime Spray Drying // Low Sulfur Diesel
LSFO	Limestone Forced Oxidation

List of Acronyms - continued

MACT	Maximum Achievable Control Technology
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MARAMA	Mid-Atlantic Regional Air Management Association
MEL	Magnesium Enhanced Lime
MM	million
MMBTU	Million British Thermal Units
MRPO	Midwest Regional Planning Organization
MW	Megawatt
NESCAUM	Northeast States for Coordinated Air Use Management
NO_X	nitrogen oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O&M	Operation and Maintenance
OFA	Over-fire Air
PADD	Petroleum Administration for Defense District
PM	Particulate Matter
PM_{10}	Particulate Matter with diameter 10 micrometers or less
$PM_{2.5}$	Particulate Matter with diameter 2.5 micrometers or less
PSD	Prevention of Significant Deterioration
RACM	Reasonably Available Control Measure
RACT	Reasonably Available Control Technology
RWC	Residential Wood Combustion
SACR	Selective Auto-catalytic Reduction
SCC	Source Classification Code
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-catalytic Reduction
SO_2	sulfur dioxide
SOFA	Separated Over-fire Air
ULSD	Ultra Low Sulfur Diesel

EXECUTIVE SUMMARY

The Regional Haze regulations set forth under 40 CFR 51.308(d)(1) require States to achieve reasonable progress toward natural visibility conditions. The national visibility goal in Class I areas is defined in the CAA Section 169A(a)(1) as "the prevention of any future, and the remedying of any existing, impairment of visibility…", and is expected to be satisfied by 2064 with a return to natural visibility conditions. States containing Class I areas must set Reasonable Progress Goals (RPGs) to define future visibility conditions that are expected (but not required) to be equal to, or better, than visibility conditions expected by the uniform rate of progress at any future year until natural conditions are achieved. RPGs are to be established for the final year in the planning period, which in the case of the first SIP is 2018.

Following draft guidance from EPA in establishing RPGs, States must set a baseline from which reasonable progress towards visibility improvement will be measured. The MANE-VU baseline year for the emission inventory is 2002 and for monitoring is 2000-2004. The next task is to identify key pollutants affecting visibility impairment at each Class I area. The major pollutant contributing to visibility impairment in MANE-VU has been shown to be sulfate.

In order to determine the key source regions and source types affecting visibility impairment at each Class I area, a contribution assessment was prepared by NESCAUM for MANE-VU. Major contributors were identified by ranking emissions sources, comparing Q/d (emission impact over distance), and modeling visibility impacts. Source apportionment and other analyses documented in MANE-VU's contribution assessment showed that several source categories have impacts on visibility at MANE-VU Class I areas.

The largest contribution to visibility impairment at most sites was from burning of coal, primarily utility and industrial combustion sources in MANE-VU and nearby States. At forested rural sites, biogenic organics are a moderate to large contributor to visibility impairment, but other sources of secondary organics also contribute. Wood smoke and ammonium nitrate were identified as small to moderate contributors.

Based on information from the contribution assessment and additional emissions inventory analysis, MANE-VU selected the following source categories for analysis in this project:

- Coal and oil-fired Electric Generating Units, (EGUs);
- Point and area source industrial, commercial and institutional boilers;
- Cement kilns;
- Lime kilns;
- The use of heating oil; and
- Residential wood combustion

This document presents the results of an analysis of the economic and environmental impacts of potential control scenarios that could be implemented by MANE-VU States to reduce emissions from the above source categories in order to make reasonable progress toward meeting visibility improvement goals. The purpose of this analysis is to present information that can be used by States to develop policies and implementation plans to address reasonable progress goals. Control technologies to achieve reasonable progress goals are evaluated with respect to four factors listed in the Clean Air Act (Section 169A):

- Cost,
- Compliance timeframe,
- Energy and non-air quality environmental impacts, and
- Remaining useful life for affected sources.

The "four factor" analysis was applied to control options identified for each of the selected source categories. Cement kilns and lime kilns are analyzed together due to the similarity of the two source categories.

The table below presents a summary of the four factor analysis for the source categories analyzed. Detailed information on control technologies assessed in this effort is presented in the main body of this document.

Table I Summary of Results from the Four Factor Analysis

Source Category	Primary Regional Haze Pollutant	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	IPM* v.2.1.9 predicts $775-$1,690 $170-$5,700 based on available literature	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	$130-$11,000 based on available literature	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, control device energy requirements, wastewater issues	10-30 years
Cement and Lime Kilns	SO_2	$1,900-$73,000 based on available literature	2-3 years following SIP submittal	Control device energy requirements, wastewater issues	10-30 years
Heating Oil	SO_2	$550-$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 and VOC	$0-$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 (IPM®) application by ICF for MANE-VU

This report also contains information on current and planned controls at 20 specific non-EGU sources and 30 specific EGU sources identified by MANE-VU to consider control strategies already in place or planned by 2018.

CHAPTER 1

INTRODUCTION

BACKGROUND

The Regional Haze regulations set forth under 40 CFR 51.308(d)(1) require States to achieve reasonable progress toward natural visibility conditions. The national visibility goal in Class I areas is defined in the CAA Section 169A(a)(1) as "the prevention of any future, and the remedying of any existing, impairment of visibility…", and is expected to be satisfied by 2064 with a return to natural visibility conditions. States containing Class I areas must set Reasonable Progress Goals (RPGs) to define future visibility conditions that are expected (but not required) to be equal to, or better, than visibility conditions expected by the uniform rate of progress at any future year until natural conditions are achieved. RPGs are to be established for the final year in the planning period, which in the case of the first SIP is 2018.

Following draft guidance from EPA in establishing RPGs, States must set a baseline from which reasonable progress towards visibility improvement will be measured. The MANE-VU baseline year for the emission inventory is 2002 and for monitoring is 2000-2004. The next task is to identify key pollutants affecting visibility impairment at each Class I area. The major pollutant contributing to visibility impairment in MANE-VU has been shown to be sulfate.

In addition to the planned reductions that will be included as part of the State SIPs for regional haze, federal programs will also have significant benefits in reducing regional haze by 2018 and beyond. A list of EPA's national and regional rules as well as voluntary programs that will assist in the reduction of fine particle pollution are as follows:

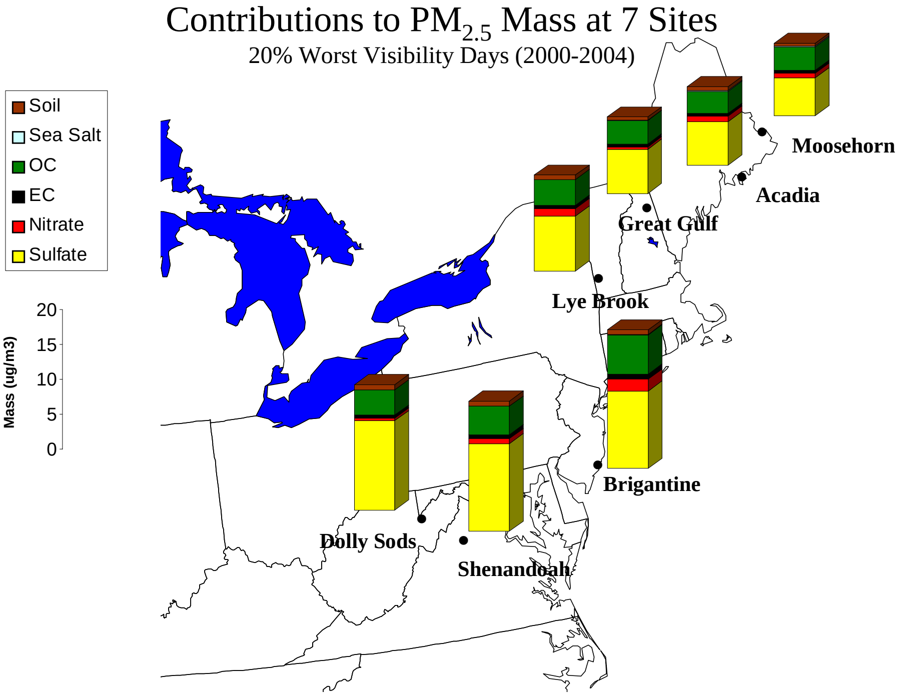
- Clean Air Interstate Rule (CAIR)
- The Acid Rain Program
- NO_X SIP Call
- 2004 Clean Air Nonroad Diesel Rule
- 2007 Clean Diesel Trucks and Buses Rule
- Tier 2 Vehicle Emission Standards and Gasoline Sulfur Program
- Emission standards for other engines (highway and non-highway use)
- National Clean Diesel Campaign
- The Great American Woodstove Changeout

More information and links to the programs listed above can be found on the following website: http://www.epa.gov/pm/reducing.html

DETERMINATION OF EMISSION SOURCE CATEGORIES AND INDIVIDUAL SOURCES MOST RESPONSIBLE FOR REGIONAL HAZE IN MANE-VU CLASS I AREAS

Particles in the $PM_{2.5}$ size range are directly responsible for visibility reduction. Figure 1.1 generated by NESCAUM from analysis of monitoring data shows the components of $PM_{2.5}$ mass at the seven Class I areas of concern on the 20% worst visibility days during the period from 2000-2004. These components of $PM_{2.5}$ are directly responsible for visibility reduction.

Figure 1.1



NESCAUM, 2006. "2000-2004 Visibility Rankings and Glide Paths.ppt." PowerPoint Presentation developed by Gary Kleiman.

From Figure 1.1, it is apparent that sulfate is the largest contributor to $PM_{2.5}$ mass at the Class I areas of concern. The second largest contributor to $PM_{2.5}$ mass is organic carbon (OC). Nitrates, elemental carbon (EC), soil, and sea salt also contribute to $PM_{2.5}$ mass.

Source apportionment and other analyses documented in MANE-VU's contribution assessment indicated that a number of source categories have impacts on visibility at MANE-VU Class I areas. The largest contribution to visibility impairment at most sites was SO_2 from coal-combustion, primarily utility and industrial sources in MANE-VU and nearby States. At forested rural sites, biogenic organics are a moderate to large contributor to visibility impairment but other sources of secondary organics also contribute. Wood smoke and ammonium nitrate were identified as small to moderate contributors (see Appendix B of the Contribution Assessment).

The contribution assessment also included an analysis of haze-associated pollutant emissions. “SO_2 is the primary precursor pollutant for sulfate particles. Sulfate particles commonly account for more than fifty percent of particle light extinction at northeastern Class I areas on the clearest days and for as much as or more than eighty percent on the haziest days.” The assessment noted that point sources dominate SO_2 emissions in the MANE-VU region. Point source emissions sources primarily consist of stationary combustion sources for generating electricity, industrial power, and heat. Commercial and residential heating constitute another important source category in MANE-VU States. An analysis of the largest sources in the region also indicates that a few large kilns are among the largest SO_2 sources in the region.

Figures 1.2 and 1.3 show the top emissions source categories of $PM_{2.5}$ and SO_2 from Version 3 of the 2002 MANE-VU emissions inventory. The largest SO_2 source categories are the largest contributors to visibility impairment in MANE-VU.

Figure 1.2 MANE-VU 2002 Version 3 Annual Emissions Inventory Top $PM_{2.5}$ Primary Source Categories

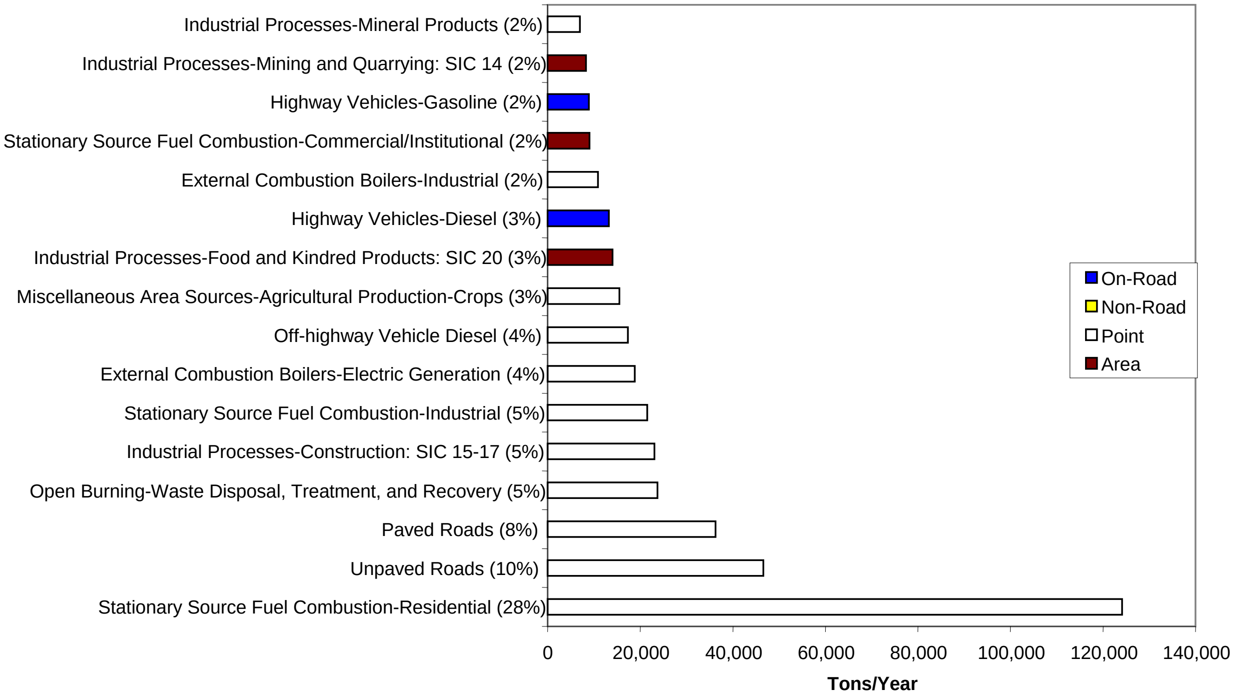
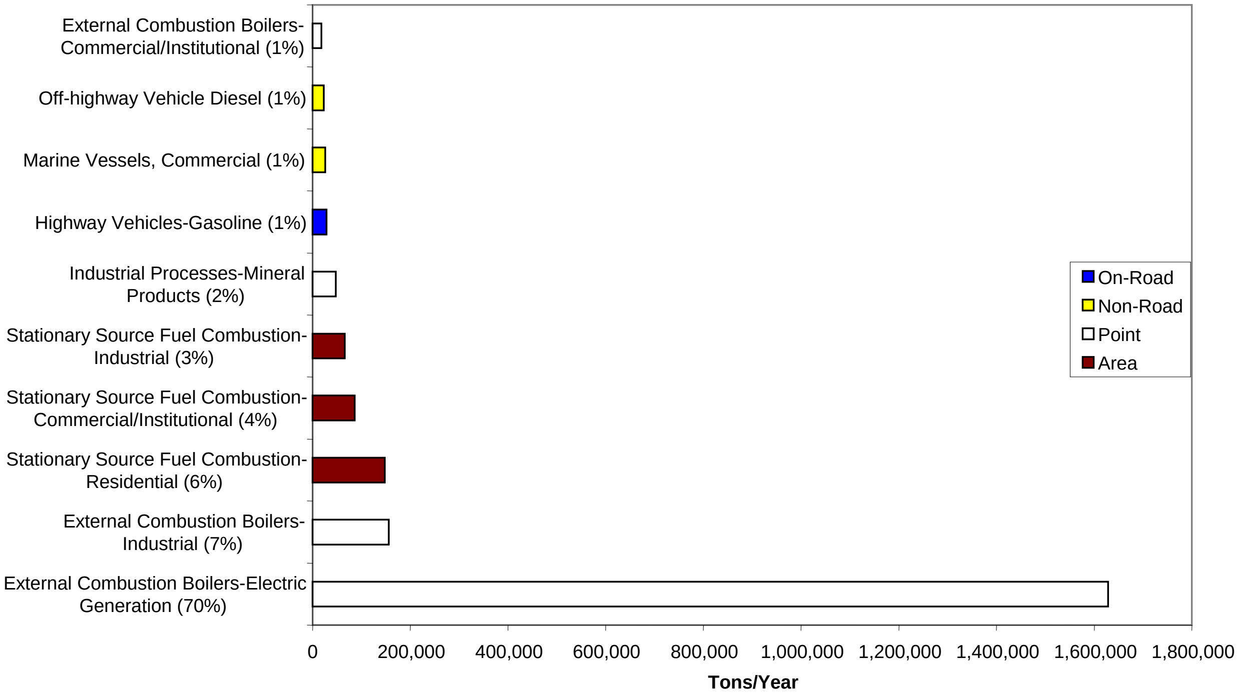


Figure 1.3 MANE-VU 2002 Version 3 Annual Emissions Inventory Top SO_2 Source Categories



<u>Description of Individual Source Identification Process and Modeling</u>

The following discussion describes the data and procedures that were used to identify the individual sources with the greatest impact on regional haze in MANE-VU Class I areas. The individual sources included in this report (see Chapters 3, 5, and 7) were determined by identifying the sources with the maximum predicted 24-hour sulfate ion impact.

From 2004 to 2006, the Vermont Department of Environmental Conservation (VTDEC) participated in MANE-VU RPO planning activities by performing regional scale screening modeling of pollutants known to contribute to regional haze at Class I areas in the MANE-VU region. The model used by VTDEC was the CALPUFF model run on a domain including most of the eastern United States. Both point and area sources were modeled for the entire year 2002, and variable hourly CEMS emission data were used for all the largest 750+ EGUs in the domain. Model results were primarily intended to be used in conjunction with other source/receptor modeling methods as part of the technical underpinning of the document, *Contributions to Regional Haze in the Northeast and Mid-Atlantic United States: Mid-Atlantic/Northeast Visibility Union (MANE-VU) Contribution Assessment*, prepared by NESCAUM for MANE-VU and dated August 2006. This document contains more detailed discussion of the approach used to develop inputs for the modeling platform, the model setup, and its validation. It can be found at the following link: http://www.manevu.org/Document.asp?fview=Reports#

Starting in 2006, through its participation on two MANE-VU RPO workgroups, (the BART Workgroup and the Reasonable Progress Workgroup), which were charged with developing technical support information for regional haze plans for the MANE-VU Class I areas, VTDEC made available some of the EGU source modeling results previously generated during its work on the contribution assessment report cited above. VTDEC also performed new point source modeling with the same CALPUFF modeling platform for a number of additional large point sources identified by the workgroups, primarily non-EGUs. The new point source modeling was performed for sources that did not have CEMS hourly emission data. This new modeling performed specifically for the workgroups differed in this fundamental way from the modeling of large EGUs with available CEMS hourly emission data which had been done for the contribution assessment. All new non-EGU point source modeling performed with CALPUFF by VTDEC for the BART and Reasonable Progress Workgroups utilized a constant average hourly emission rate (annual tons/8760) for the year 2002 based on emissions provided by the individual States in which the sources were located. Except for a more complete set of discrete receptors covering each Class I area, all other inputs and settings of the CALPUFF modeling system, including the NWS Observation-based CALMET created wind-fields, were exactly the same as used in the contribution assessment modeling work.

For the Reasonable Progress Workgroup, VTDEC assembled the results of its earlier individual CEMS-based stack modeling of EGUs into tables which listed the maximum 24-hr (calendar day) sulfate ion impact predicted at any receptor in each Class I area due to the emissions from each individual EGU modeled (more than 750). Because the largest contributing pollutant to visibility impairment in all the MANE-VU Class I areas is the sulfate ion, the Reasonable Progress Workgroup felt that ranking point sources based on this maximum 24-hour impact alone would be an appropriate way to prioritize their relative potential for improving visibility and making reasonable progress at these areas. Once the maximum 24-hr sulfate ion impacts modeled for 2002 were ranked from greatest to smallest by EGU, the top impacting EGUs were identified for each of the Class I areas.

In order to examine and prioritize potentially controllable non-EGU large point sources of SO_2 located both within MANE-VU and external to MANE-VU, the Reasonable Progress Workgroup examined the 2002 NEI based on SIC code selections. Selected stack points for sources selected were modeled individually using the stack parameters and the constant annual average emission rate of SO_2 only. VTDEC converted the annual total tons of SO_2 reported by the state to the NEI for that stack point into an average hourly emission rate and ran the CALPUFF model for the 194 largest points identified in three lists supplied by Delaware. The selection of points to model was based first on a selection of the top 100 emitting points modeled from a group of several hundred ICI boilers (list 1) and Cement and Lime Kilns (list 2) identified by SCC code and extracted from the 2002 NEI database. Later this list of 100 stack emission points to model was expanded by adding the top 94 stack points not previously included in the ICI and kiln lists, but identified by more inclusive selection criteria based on SCC codes (list 3) and ranked by annual SO_2 emissions.

The maximum predicted 24-hour sulfate ion impact from each of the 194 non-EGUs modeled were combined into an ordered table showing the largest impacting non-EGU at top and the least impacting non-EGU at the bottom for each Class I area. A similar ordered table was created showing the annual average sulfate ion impacts of these 194 non-EGU stack points. The top non-EGUs impacting each Class I area were then selected from the top of each list.

The ranked listings for EGUs represent the EGUs most likely to produce the largest sulfate ion impact at each Class I area on a 24-hour basis. The EGU modeled results were based on variable hourly SO_2 emissions from the CEMS data submitted by the sources themselves. For the EGUs, the modeled stack ID for which the hourly SO_2 emission was reported might be a single electric generating unit or it might be a combination of two or more individual electric generating units operating at a plant and emitting from the same stack. The CALPUFF modeling was done on the emission rate supplied for the particular hour of the year 2002 and did not determine whether that emission was from a single EGU or from a combination of several at a plant. Therefore, to identify which particular unit at a plant reporting multiple units emitting from a single stack is responsible for the specific impact due to that hourly emission, would require more information than was available to VTDEC. The reported impact is from the stack and the distribution among units combined in that stack's CEMs data cannot be determined from the modeling results.

For the non-EGU points modeled, there is a slight probability that emissions modeled may have been only from a particular "process" level in the NEI database structure. There may have been more than one process reported for the same emission point during the year 2002 so that a sum of two or more process annual emissions should be modeled and summed for the entire unit level emission control potential to be identified. The top modeled impacts are simply the top for each area based on the 194 separate stack points modeled with each individual annual average emission rate supplied from one of the three NEI selected listings VTDEC received.

APPROACH TO DEMONSTRATING REASONABLE PROGRESS

Based on the contribution assessment, including modeling and emissions inventory analysis, MANE-VU selected the following source categories for analysis in this project:

- Coal and oil-fired Electric Generating Units, (EGUs);
- Point and area source industrial, commercial and institutional boilers;
- Cement kilns;
- Lime kilns;
- The use of heating oil; and
- Residential wood combustion

This document presents the results of an analysis of the economic and environmental impacts of potential control scenarios that could be implemented by MANE-VU States to demonstrate reasonable progress toward meeting visibility improvement goals. The purpose of this analysis is to present information that can be used by States to develop policies and implementation plans to address reasonable progress goals. Control technologies to achieve reasonable progress goals are evaluated with respect to four factors listed in the Clean Air Act (Section 169A):

- Cost,
- Compliance timeframe,
- Energy and non-air quality environmental impacts, and
- Remaining useful life for affected sources.

The “four factor” analysis is applied to control options identified for the selected source categories. The analysis of cement kilns and lime kilns was combined into one section due to the similarity of the two sources.

Category analyses are presented for electric generating units (EGUs), industrial, commercial, and institutional (ICI) boilers, cement kilns, lime kilns, distillate-oil fired heating units, and residential wood combustion. Only sulfur dioxide (SO_2) emissions are considered for the first five categories. The SO_2 emitted from sources in these five source categories comprised approximately 90% of all SO_2 emitted from within MANE-VU in 2002. For residential wood combustion, the analysis is presented for particulate matter. $PM_{2.5}$ emissions from this source were 28% of the total $PM_{2.5}$ emitted from within MANE-VU in 2002. Biomass burning causes both direct emissions of primary particles and emissions of volatile organics which can contribute to the formation of secondary organic carbon particles. Organic carbon is typically the second-largest contributor to regional haze in the MANE-VU region.

For EGUs, ICI boilers, and kilns control options include fuel switching, fuel preparation, *in-situ* modifications, and add-on controls. Because of the similarity in available control options, cement and lime kilns have been combined into one category. For oil-fired heating oil, the only control option considered is reduction in sulfur content in the fuel oil. For residential wood combustion and outdoor wood-fired boilers, we have included descriptions of alternative technologies for replacement and emission reduction.

Additionally, we have assembled current and planned controls for the 20 specific non-EGU and 30 EGU sources based on information from State agencies and Integrated Planning Model (IPM®). The purpose of selecting these sources is to find out whether the sources that have the greatest impacts on Class I areas near MANE-VU in 2002 are already controlled or will be controlled by 2018. In many cases, States have supplied a schedule of planned controls for these facilities, which we have included in tabular form in this report. In the case of EGUs, we obtained information from the States and from modeled projections developed using Integrated Planning Model (IPM®).

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CHAPTER 2

SOURCE CATEGORY ANALYSIS: ELECTRIC GENERATING UNITS (EGUs)

SOURCE CATEGORY DESCRIPTION

The MANE-VU contribution assessment demonstrated that the principal contributor to visibility impairment in Class I MANE-VU areas and Class I areas affected by emissions from sources within MANE-VU is SO_2 from EGUs. Roughly 70% of the 2.3 million tons of SO_2 emissions in the 2002 emissions inventory (2002 MANE-VU Emissions Inventory Version 3) were from EGUs, making them the largest source category contributing to regional haze in terms of total visibility impairing emissions and in terms of number of facilities.

Boilers at EGUs burn various fuels to produce heat for steam production which is then used to drive turbine generators for electricity production. The primary fuel combusted in EGU boilers in the eastern United States is coal from mines in the Midwest and Appalachia. Coal from this region generally contains 2-4% sulfur. The sulfur contained in the coal is emitted as SO_2 from the boiler. Coal obtained from western States is generally lower in sulfur, with a sulfur content of <1%.

Nationally, 90% of the SO_2 emissions from the EGUs are from coal-fired electric utility boilers. These coal-fired utility boilers are also the largest sources of NO_X and PM emissions, which also contribute to regional haze. All coal-fired electric utility power plants in the United States use control devices to reduce PM emissions. Additionally, many of the boilers are required to use controls for SO_2 or 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. According to the EPA Clean Air Markets Division, (Personal communication with Mr. Peter Kokopeli, EPA – CAMD on April 3, 2007), as of January 1, 2006, the percentage of coal-fired EGU capacity in the United States with SO_2 and/or NO_X control devices (as a percentage of heat input), were as follows:

> 2% of coal-fired EGU capacity had SO_2 control only;
> 57% of coal-fired EGU capacity had NO_X control only;
> 32% of coal-fired EGU capacity had SO_2 and NO_X controls;
> 9% of coal-fired EGU capacity had no SO_2 or NO_X controls.

As 66% of coal-fired EGU capacity, (as a percentage of heat input), have no SO_2 controls, there is room for significant reductions in emissions of SO_2. There is currently a trend towards improving control of SO_2 through installation of additional controls and making other process and fuel changes. The four factor analysis of potential control scenarios for EGUs contained in this chapter addresses the control options and costs, time requirements, energy and non-air impacts, and source life associated with these controls.

Although PM and NO_X from coal-fired utility boilers contribute to regional haze, the MANE-VU contribution assessment conducted by NESCAUM determined that SO_2 from power plants was the largest contributor to regional haze in the MANE-VU Class I areas. Therefore, the focus of this control option analysis for coal-fired boilers is on SO_2 controls. Effects of the SO_2 control options on PM and NO_X emissions are addressed where applicable, to ensure that the impact on emissions of these pollutants is considered for planning purposes.

In addition to coal combustion, some EGUs in MANE-VU States also burn fuel oil and/or natural gas. However, the EGU sources with the greatest impact on MANE-VU Class I areas were all coal-fired units. Emissions of SO_2 from natural gas combustion are negligible, but SO_2 emissions from fuel oil combustion are directly proportional to the sulfur content of the fuel. The cost of switching from a high sulfur distillate fuel oil to a lower sulfur distillate fuel oil is addressed in Chapter 8 of this report.

The SCCs applicable to coal-fired utility boilers include SCCs beginning 1-01-001-XX, 1-01-002-XX, and 1-01-003-XX.

EVALUATION OF CONTROL OPTIONS

Effective post-combustion SO_2 controls for EGUs and particularly coal-fired boilers are well understood and have been applied to a large number of sources over the years in response to regulations in the form of NSPS, PSD/NSR, State RACT Rules and the Title IV Acid Rain Program. Additional SO_2 reductions are anticipated as a result of the Clean Air Interstate Rule (CAIR), which was finalized on May 12, 2005.

In addition to post-combustion controls that can be applied to reduce emissions of SO_2 from coal-fired boilers, there are other strategies that can be used to reduce emissions of SO_2. Examples of such strategies include switching to a fuel with a lower sulfur content, and coal cleaning prior to combustion. Methods of SO_2 control applicable to coal-fired boilers are listed in Table 2.1 with a brief description of the control option, applicability, and range of performance. A more detailed description of the control option and an analysis of the four factor assessment for reasonable progress follow the table.

MACTEC assembled the list of available SO_2 control options for the EGU source category given in Table 2.1 from available documentation. Note that the estimated performance of each control option varies greatly and depends on a variety of site specific factors, including the boiler type. Examples of three major types of coal-fired boiler include fluidized bed combustors, stoker boilers, and pulverized coal boilers. In addition to these three types of coal-fired boilers there are many subcategories of boilers, characterized by their specific design. Control devices designed for these types of boilers vary in terms of cost as well as estimated performance.

Table 2.1 SO_2 Control Options for Coal-fired EGU Boilers

Technology	Description	Applicability	Performance
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	Potential control measure for all coal-fired EGUs currently using coal with high sulfur content	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal
Switch to natural gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-fired EGUs	Virtually eliminate SO_2 emissions by switching to natural gas
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired EGUs	20-25% reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) - Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemicals are sometimes used)	Applicable to all coal-fired EGUs	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) –Dry	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

Table references:
1. *Assessment of Control Technology Options for BART-Eligible Sources*, NESCAUM, March 2005.
2. *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options, STAPPA-ALAPCO*, March 2006.

Switch to Low Sulfur Coal

Fuel switching encompasses several different control options. Often it is not possible to completely switch from one type of fuel to another. One option is blending lower-polluting fuels with baseline fuels to reduce overall emissions. For example, many coal-fired boiler operators blend lower sulfur subbituminous coals with high sulfur bituminous coals to reduce SO_2 emissions. In other cases, bituminous coals with a lower sulfur content can be substituted for high sulfur bituminous coal.

The feasibility of fuel switching depends partly on the characteristics of the plant and the particular type of fuel change being considered. Many plants will be able to switch from high-sulfur to low-sulfur bituminous coal without serious difficulty, but switching from bituminous to subbituminous coal may present greater challenges and costs. In some instances, fuel switching will require significant investment and modifications to an existing plant. Switching to a lower sulfur coal can affect coal handling systems, boiler performance, PM control effectiveness and ash handling systems. In any case, fuel switching or blending has been a key strategy used by EGUs to comply with the federal Acid Rain Program. Overall SO_2 reductions estimated from switching to low-sulfur coal range from 50-80%.

Switch to Natural Gas

Switching from coal combustion to natural gas combustion virtually eliminates SO_2 emissions, but it is currently uneconomical to consider this option for base load EGUs due to the fuel quantity necessary and the price of natural gas. The price of natural gas and coal are variable, but in terms of heating value, the price of natural gas over the past several years has been several times higher than coal. According to information published on the EIA website, in January 2007 the price of natural gas was approximately four times higher than coal according to average monthly costs of fuel delivered to electricity producers during that month.

Coal Cleaning

According to the 2006 STAPPA-ALAPCO document on control technologies titled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*, coal cleaning or washing is a widely practiced method of reducing impurities in coal, particularly sulfur. Reducing the sulfur content of the fuel used in the boiler reduces the SO_2 emissions proportionally. Coal cleaning has been shown to reduce SO_2 emissions by 20-25%, while increasing the heating value of the fuel. Additional removal can be achieved through advanced chemical washing techniques, but no detailed information on these techniques was available.

Conventional (physical) coal washing techniques remove ash and sulfur from coal by crushing the fuel and separating the components in a liquid bath, such as water. The lighter coal particles float to the top of the bath for recovery, while the heavier impurities sink to the bottom for removal.

Coal sulfur exists in two forms, inorganic and organic. The inorganic sulfur in coal called pyrite is primarily in the form of ferrous sulfate ($FeSO_4$). Because it is not chemically bound within the coal, 40-50% of this pyrite can be removed through coal washing. The organic form of sulfur is chemically bound in the molecular structure of the coal itself and cannot be physically washed out. Organic sulfur accounts for between 35-75% of the total sulfur in Illinois Basin coals in the example given by STAPPA-ALAPCO. Depending on the percentage of the sulfur in a given coal sample which exists in the form of pyrite, varying amounts of the total sulfur can be removed.

Although there are benefits associated with coal washing, there are limitations associated with this technology. The 20-25% SO_2 reduction is beneficial, but post-combustion controls have been shown to reduce SO_2 emissions by greater percentages. Also, solid and liquid wastes are generated using the washing process and must be addressed.

Flue Gas Desulfurization (FGD) - Wet

There are three types of FGD scrubbers: wet, spray dry, and dry. According to the 2006 STAPPA-ALAPCO document on control technologies titled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*, EPA reports that 85% of the FGD systems in the

United States are wet systems. Twelve percent of the FGD systems are spray dry systems, and 3% are dry systems. The operating parameters, impacts on capacity factor, and costs of each SO_2 removal method are different. Capacity factor is the amount of energy a facility generates in one year divided by the total amount it could generate if it ran at full capacity.

SO_2 in the 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”. Most wet FGD systems 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 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. Integrated Planning Model (IPM®) used by EPA to predict future EGU control strategies assumes that this technology will be used to control SO_2 from coal-fired boilers that are 100 MW or larger, that combust bituminous coal with 2% or higher sulfur content by weight. Integrated Planning Model (IPM®) documentation refers to the specific scrubber technology as Limestone Forced Oxidation, (LSFO), and assumes 95% SO_2 removal using this technology. Data and documentation obtained for use in this report are from Integrated Planning Model (IPM®) version 2.1.9.

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 disposal of large quantities of waste sludge.

Another wet scrubber technology used to control emissions of SO_2 from EGUs is Magnesium Enhanced Lime, (MEL). This technology is available to coal-fired boilers from 100 MW to 550 MW in capacity, that combust bituminous, sub-bituminous or lignite coal with less than 2.5% sulfur content by weight. Integrated Planning Model (IPM®) assumes that MEL provides 96% SO_2 removal.

The SO_2 removal efficiencies of existing wet limestone scrubbers range from 31-97%, with an average of 78%. The SO_2 removal efficiencies of existing wet lime scrubbers range from 30 to 95%. 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.

Flue Gas Desulfurization (FGD) – Spray Dry

A spray dryer absorber (sometimes referred to as wet-dry or semi-dry scrubber) 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 sludge 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 60-95%.

Lime Spray Drying (LSD) is a dry SO_2 scrubber technology applied in Integrated Planning Model (IPM®) runs for coal-fired boilers 550 MW or larger that combust bituminous, subbituminous or lignite coal with sulfur content between 0.4% and 2% sulfur by weight. Integrated Planning Model (IPM®) assumes that LSD provides 90% SO_2 removal.

Flue Gas Desulfurization (FGD) –Dry

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 40-60%.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR EGUs

Each of the control options presented in Table 2.1 is evaluated in this section according to the four factors for determining reasonable progress as required by Section 169A(g)(1) of the Clean Air Act and 40 CFR 51.308(d)(1)(i)(A). The information provided in this section is intended to be used by the States in setting Reasonable Progress Goals for reducing regional haze in the MANE-VU Class I areas.

Cost of Compliance

For EGUs, EPA used Integrated Planning Model (IPM®) to predict which units will install controls at what costs and which units will buy credits. Integrated Planning Model (IPM®) predicts a least-cost solution to meet power production demands within emissions constraints. Emissions may be reduced by fuel-switching, use of controls or by using power from a cleaner unit. The RPOs made some Integrated Planning Model (IPM®) runs to determine which units will install controls to comply with the EPA CAIR rule. Additionally, MANE-VU investigated an even more stringent "CAIR Plus" strategy using Integrated Planning Model (IPM®). In Chapter 3, the parsed results (projections disaggregated to the unit level), available for the CAIR Plus strategy are used to help estimate costs for specific EGUs. It should be noted that Integrated Planning Model (IPM®) is an industry-wide model, and the control costs output from the model represent the industry-wide average cost of control that can be expected based on a set industry-wide emission reduction. Integrated Planning Model (IPM®) results can also be viewed as the predicted cost of control at a model plant. The costs of control at individual facilities are dependent on a number of factors and cannot be determined for any specific individual facility from Integrated Planning Model (IPM®) results.

Table 2.2 contains the marginal costs of SO_2 emission reductions, also known as the SO_2 allowance price, for MANE-VU Base Case CAIR, (MARAMA_5c), and CAIR Plus, (MARAMA 4c), Integrated Planning Model (IPM®) runs. These costs include the capital costs of new investments, fuel costs, and the operation and maintenance costs of power plants. For both the CAIR and CAIR Plus run, Integrated Planning Model (IPM®) installed scrubbers to meet the demand for SO_2 reduction while meeting the demand for electricity. Integrated Planning Model (IPM®) also installed NO_X controls, but the cost of achieving the NO_X emissions reductions was provided independently from SO_2 controls. Application of SO_2 controls such as use of cleaner and lower-sulfur coals or post combustion controls such as wet scrubbers generally help to reduce PM emissions in addition to SO_2. SO_2 controls generally do not affect PM or NO_X emissions.

Table 2.2 Marginal Costs of Emission Reductions (Allowance Prices) Calculated by Integrated Planning Model (IPM®) for the CAIR Base Case and CAIR Plus Runs (2006 $/ton)

Pollutant	CAIR Base Case (MARAMA_5c)						CAIR Plus Policy Case (MARAMA_4c)					
	2008	2009	2010	2012	2015	2018	2008	2009	2010	2012	2015	2018
SO_2	774	837	905	979	1,141	1,338	975	1,055	1,139	1,233	1,437	1,684

Table reference:
Final Draft Report - Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®), ICF Resources; May 30, 2007.
Note – A conversion factor of 1.2101 was used to convert the dollar values from 1999 to 2006
www.inflationdata.com

The CAIR Plus strategy requires additional SO_2 and NO_X control beyond EPA's CAIR program. ICF's report on the CAIR and CAIR Plus Integrated Planning Model (IPM®) runs titled: *Final Draft Report - Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning*

Model (IPM®), states that the power sector opts for a technology strategy for complying with the CAIR Plus proposal requirements. In the CAIR Plus analysis, the CAIR Plus region requires the installation of an additional 19.5 GW of scrubbers and 77.8 GW of SCR by 2012. These controls represent a 30% increase in scrubbers and 185% increase in SCRs in 2012 compared to the Integrated Planning Model (IPM®) CAIR run. By 2018, the cumulative installation of scrubbers is 17% higher and the installation of SCR is 98% higher for the CAIR Plus run compared to the CAIR run. The resulting SO_2 and NO_X emissions from the CAIR and CAIR Plus Integrated Planning Model (IPM®) runs are listed for MANE-VU in Table 2.3.

Table 2.3 NO_X and SO_2 Emissions from the Electric Power Sector (Thousand Tons)

	2008 SO_2 | NO_X	2009 SO_2 | NO_X	2010 SO_2 | NO_X	2012 SO_2 | NO_X	2015 SO_2 | NO_X	2018 SO_2 | NO_X
CAIR Base Case (MARAMA_5c)	802 | 386	650 | 272	518 | 213	463 | 209	410 | 202	394 | 199
CAIR Plus Policy Case (MARAMA_4c)	735 | 376	556 | 228	396 | 159	376 | 162	312 | 153	271 | 146

Table reference:
Final Draft Report - Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®), ICF Resources; May 30, 2007.

Cost of Switching to Low Sulfur Coal

Switching to a low-sulfur coal or blending a lower sulfur coal can impact cost due to the following two main reasons:

1. The cost of low-sulfur coal compared to higher sulfur coal
2. The cost of necessary boiler or coal handling equipment modifications

The cost of low-sulfur coal compared to higher sulfur coal is not only related to the “dollar per ton” cost of the coal, but also related to the heating value of the coal.

Recent data from the Energy Information Administration show the average price of coals from various locations together with estimated heating values and sulfur content. The prices of coal indicated in Tables 2.4 and 2.5 do not include the cost of delivery.

The energy-based cost of each of the coals listed in Table 2.4 is approximately the same, with the exception of coal from the Powder River Basin. Powder River Basin coal has a significantly lower heating value than the other four varieties of coal, but on an energy basis, it is still approximately one third the cost of the other coals listed. Since Powder River Basin coal contains significantly less sulfur, it would seem that this coal would be the best fuel for boilers trying to incorporate a lower sulfur coal. Unfortunately, due to the lower heating value of the coal, boilers that are configured to burn coal with a higher heating value can only use a small percentage of this low-sulfur coal (no higher than 15% Powder River Basin coal). The only way to burn higher percentages of the Powder River Basin coal would be to extensively retrofit the boilers or suffer from poor boiler performance and other operating difficulties. Such retrofits should be reviewed in light of current Prevention of Significant Deterioration (PSD) permitting regulations to ensure that all such requirements are met and that emissions do not increase. The coal prices included in Table 2.4 do not reflect the cost of boiler retrofits required to combust low sulfur coal.

Table 2.4 Recent Average Coal Prices from Various Locations in the U.S. (12/2006) ($/ton)

	Central Appalachia (Bituminous)	Northern Appalachia (Bituminous)	Illinois Basin (Bituminous)	Powder River Basin (Subbituminous)	Uinta Basin (Low-S Bituminous)
Coal Heating Value (BTU/lb)	12,500	13,000	11,000	8,800	11,700
Sulfur Content (%)	1.2	<3	5	0.8	0.8
Cost/ton ($)	$47.25	$43.00	$33.33	$9.85	$36.00

Table reference:
EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html

The two types of coal used for fuel in EGU boilers in the United States are bituminous and subbituminous coals. Bituminous coals have varying amounts of sulfur, but the sulfur content of bituminous coal is generally higher than subbittuminous coal. Traditionally, many EGU boilers have been designed to combust bituminous coal because of the higher carbon content and heating value.

Table 2.5 shows the average 2005 cost data from the Energy Information Administration for bituminous and subbituminous coal. The purpose of this information is to demonstrate the difference in cost of these coals based on their heating value. Assuming a heat content for bituminous coal of 12,000 BTU/lb and 10,000 BTU/lb for subbituminous coal allows the calculation of the cost of the coal on an energy basis. The coal prices included in Table 2.5 do not reflect the cost of boiler retrofits required to combust low sulfur coal.

Table 2.5 Average U.S. Bituminous and Subbituminous Coal Prices (2006 dollars/ton)

Fuel	Average Price per Ton	Average Price per MMBTU
Bituminous Coal	$38.00	$1.58
Subbituminous Coal	$8.96	$0.44

Table reference:
EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html
Note – A conversion factor of 1.0323 was used to convert the dollar values from 2005 to 2006 www.inflationdata.com

Switching to subbituminous coal can reduce SO_2 emissions by up to 80%, but changes must be made to the boilers to compensate for the lower heating value of the subbituminous coal. Much of the difference in fuel price is due to the difficulty in using subbituminous coal in boilers designed to combust bituminous coal. The 2006 STAPPA-ALAPCO document, *Controlling Fine Particulate Matter Under the Clean Air Act*, states that "fuel substitution is not feasible for sources where the substitution would require excessive retrofits or would entail substantial performance losses."

Cost of Coal Cleaning

The World Bank reports that the cost of physically cleaning coal varies from $1 to $10 per ton of coal cleaned, depending on the coal quality, the cleaning process used, and the degree of cleaning desired. In most cases the costs were found to be between $1 and $5 per ton of coal cleaned. Based on the recent prices of coal from Tables 2.4 and 2.5, this cost represents a 2-15% increase in the cost of coal.

In addition to lowering the emissions from coal combustion, coal cleaning also increases the heating value of the fuel. This lowers the transportation cost of the fuel per unit of energy, offsetting the costs associated with the coal washing. It is not clear whether this has been taken into account in the cost information provided by the World Bank.

Cost of Flue Gas Desulfurization (FGD) – Wet

The cost of flue gas desulfurization varies depending on a number of factors including the size of the boiler, SO_2 reduction requirements, boiler capacity factor, and fuel sulfur content. Taking these factors into account, the typical cost effectiveness of a 1,000 MMBTU/hr (~300MW) coal-fired boiler equipped with wet FGD is around $410 per ton of SO_2 reduced when combusting high-sulfur coal. This cost is based on a boiler capacity factor of 83% and SO_2 removal efficiency of 90%. Assuming the same boiler and SO_2 control efficiency, but firing low-sulfur coal, the cost per ton is slightly more expensive at $510 per ton of SO_2 controlled. (*Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, March 2006) (Converted from 2003 to 2006 dollars using a conversion factor of 1.0959 www.inflationdata.com)

A similar cost estimation from the same STAPPA-ALAPCO document provides information for boilers in the size range of >4,000 MMBTU/hr (~ 1,200 MW) and <4,000 MMBTU/hr achieving >90% SO_2 removal efficiency. These cost estimates demonstrate the initial and ongoing costs of installing wet scrubbers. For units >1,200 MW, the capital costs are between $380-$850/MW; operation and maintenance costs (O&M) range from $7-$27/MW; and the ultimate cost effectiveness is shown to be from $230-$570/ton SO_2 removed. For boilers <1,200 MW, the capital costs are between $850-$5,100/MW; operation and maintenance costs (O&M) range from $28-$68/MW; and the ultimate cost effectiveness is shown to be from $570-$5,700/ton SO_2 removed. This information demonstrates a strong cost effectiveness advantage realized by installing control devices on the larger emission units. (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383 www.inflationdata.com)

In another independent analysis of control costs, Integrated Planning Model (IPM®) background documentation defines a range of control efficiencies, costs, and applicability based on unit size and coal type. (http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html) Two wet scrubber (wet FGD) control technologies are discussed in Integrated Planning Model (IPM®)

background documentation; (1) Limestone Forced Oxidation (LSFO), and (2) Magnesium Enhanced Lime (MEL). Both of the scrubber control technologies are applicable to distinct unit sizes and coal types, but there is no indication in the parsed Integrated Planning Model (IPM®) results as to which type of scrubber has been applied by the model. Both scrubber technologies are assumed to achieve a SO_2 removal percentage of 95% or greater. According to Integrated Planning Model (IPM®) documentation, the costs used by Integrated Planning Model (IPM®) for these control technologies were developed by EPA and presented in a document titled *Emissions: A Review of Technologies*, (EPA-600/R-00-093), October 2000 prepared by EPA's Office of Research and Development. The cost and performance calculations were primarily a function of heat rate, capacity, and sulfur content. The range of various scrubber costs is included in Attachment 1. Using the data in Attachment 1 and applying a standard engineering economics analysis (Attachment 2), the costs of SO_2 removal using these control technologies vary from approximately $300-$1,100 per ton of SO_2 removal, (Converted from 1999 to 2006 dollars using a conversion factor of 1.2101 www.inflationdata.com).

Cost of Flue Gas Desulfurization (FGD) – Spray Dry

The cost of flue gas desulfurization varies depending on a number of factors including the size of the boiler, SO_2 reduction requirements, boiler capacity factor, and fuel sulfur content. Taking these factors into account, the typical cost effectiveness of a 1,000 MMBTU/hr (~300MW) coal-fired boiler equipped with spray dry FGD is around $420 per ton of SO_2 reduced. This cost is based on a boiler capacity factor of 83% and SO_2 removal efficiency of 90%. (*Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, March 2006) (Converted from 2003 to 2006 dollars using a conversion factor of 1.0959 www.inflationdata.com)

EPA reports in a 2005 document titled *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*, that conventional Spray Dry FGD systems can cost from $155-$237 per kW, have fixed operation and maintenance costs ranging from $1.55-$7.25 per kW-yr, and variable operation and maintenance costs from 0.2-0.7 mills/kWh. These costs are associated with a 300 MW plant. (Converted from 2005 to 2006 dollars using a conversion factor of 1.0322 www.inflationdata.com)

A similar cost estimation from STAPPA-ALAPCO, 2006 provides information for boilers in the size range of >2,000 MMBTU/hr (~600 MW) and <2,000 MMBTU/hr achieving from 80-90% SO_2 removal efficiency. These cost estimates provide the initial and ongoing costs of installing wet scrubbers. For units >600 MW, the capital costs are between $140-$510/MW; operation and maintenance costs range from $14-$34/MW; and the ultimate cost effectiveness is shown to be from $170-$340/ton SO_2 removed. For boilers <600 MW per hour, the capital costs are between $510-$5,100/MW; operation and maintenance costs (O&M) range from $34-$1,020/MW; and the ultimate cost effectiveness is shown to be from $570-$4,550/ton removed. As was the case with wet scrubbers, this information demonstrates a strong cost effectiveness advantage realized by installing control devices on the larger emission units. (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383 www.inflationdata.com)

Integrated Planning Model (IPM®) background documentation defines a range of control efficiencies, costs, and applicability based on unit size and coal type.

(http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html) Lime Spray Dry (LSD) technology is one form of SO_2 control applied by Integrated Planning Model (IPM®). LSD is assumed to achieve a SO_2 removal percentage of 90%. According to Integrated Planning Model (IPM®) documentation, the costs used by Integrated Planning Model (IPM®) for these control technologies were developed by EPA and presented in a document titled *Emissions: A Review of Technologies*, (EPA-600/R-00-093), October 2000 prepared by EPA's Office of Research and Development. The cost and performance calculations were primarily a function of heat rate, capacity, and sulfur content. The range of various scrubber costs is included in Attachment 1. Depending on boiler size, boiler capacity factor, and coal sulfur content, the fixed capital costs range from \$142 to \$183/kW, while fixed operation and maintenance costs (O&M) range from \$5 to \$7/kW-yr and variable O&M costs range from 1.9 to 2.4 mills/kWh. Assuming the typical costs in Attachment 1, an EGU rated 800 MW, a capital cost investment of \$156/kW or \$125 million would be expected. Fixed O&M and variable O&M costs would be approximately \$6/kW-yr and 2.2 mills/kWh respectively and would depend on the EGU annual output. This cost could be expected to reduce SO_2 emissions by 90%. The cost and performance calculations were primarily a function of heat rate, capacity, and sulfur content. Using the data in Attachment 1 and applying a standard engineering economics analysis (Attachment 2), the costs of SO_2 removal using this control technology varies from approximately \$480-\$600 per ton of SO_2 removal, (Converted from 1999 to 2006 dollars using a conversion factor of 1.2101 www.inflationdata.com).

Cost of Flue Gas Desulfurization (FGD) – Dry

The cost of flue gas desulfurization varies depending on a number of factors including the size of the boiler, SO_2 reduction requirements, boiler capacity factor, and fuel sulfur content. Taking these factors into account, the typical cost effectiveness of a 1,000 MMBTU/hr (~300MW) coal-fired boiler equipped with dry FGD is around \$693 per ton of SO_2 reduced when combusting high-sulfur coal. This cost is based on a boiler capacity factor of 83% and SO_2 removal efficiency of 40%. Assuming the same boiler and SO_2 control efficiency, but firing low-sulfur coal, the cost per ton is slightly higher at \$764 per ton of SO_2 controlled. (*Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, March 2006) (Converted from 2003 to 2006 dollars using a conversion factor of 1.0959 www.inflationdata.com)

The 2005 EPA document titled, *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*, shows that advanced dry FGD systems can cost from \$50-\$150 per kW, have fixed operation and maintenance costs ranging from <\$1 -\$3 per kW-yr, (based on 1-2% of capital), and variable operation and maintenance costs from 0.2-0.7 mills/kWh. Assuming an SO_2 reduction percentage of 40%, capacity factor of 85%, coal sulfur content of 1.5%, and coal heat content of 12,000 BTU/lb and applying a standard engineering economics analysis (Attachment 2), the costs of SO_2 removal using this control technology varies from approximately \$250-\$850 per ton (Converted from 2005 to 2006 dollars using a conversion factor of 1.0322 www.inflationdata.com)).

Summary of SO_2 Reduction Costs

The cost of SO_2 reductions on a per ton basis for EGUs is dependent on the cost (and availability) of fuels, boiler size and type, equipment retrofit costs, the desired emission reduction, and other site specific factors. Although these factors can cause the cost of the reductions to be well above or below the industry average, a summary of estimated ranges for SO_2 reductions is included in Table 2.6 for FGDs. Sufficient data were not available to calculate a range of costs with reasonable certainty for fuel switching or coal cleaning. Within the range of estimated costs for a given boiler size, the low end of the SO_2 reduction cost is generally associated with a high boiler capacity factor. The reason for this is due to the high capital costs and fixed operation and maintenance costs of the control device. With higher boiler capacity factors, the control device is able to reduce more tons of SO_2, which effectively reduces the per ton cost of the reduction.

Table 2.6 Estimated Cost Ranges for SO_2 Control Options for Coal-fired EGU Boilers (2006 dollars/ton of SO_2 Reduced)

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

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

4. U.S. EPA. EPA-600/R-05/034; *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*; March 2005.
5. U.S. EPA. Integrated Planning Model (IPM®) background documentation located on website: http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html
6. *Final Draft Report - Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®), ICF Resources*; May 30, 2007.
7. World Bank Organization. Information located on website: http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/aqsocc.stm

Time Necessary for Compliance

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 I of the 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. For the purposes of this review, we have assumed that a maximum of 2 years after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning) and a maximum of 3 years is adequate for the installation of post combustion controls.

For post-combustion controls, site-specific information must be supplied to vendors in order to determine the actual time needed for installation of a given control. Large scale implementation of control devices within the EGU sector, particularly in a short time period, may require consideration of impacts on regional electricity demands. Integrated Planning Model (IPM®) has allowed for these and other impacts in determining the least cost approach to emission reductions, however, there is a great deal of uncertainty associated with modeled results in comparison to real-world applications of control strategies.

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 Impacts

Fuel switching and cleaning may add to transportation issues and secondary environmental impacts from waste disposal and material handling operations (e.g. fugitive dust). Additionally, these SO_2 control methods can create fuel supply problems if several large customers of various types of coal suddenly make changes in purchasing patterns. The main impact would be on the stability of fuel prices. It is not likely that this would be a persistent problem.

Another impact of fuel switching is that the modifications required for switching from one fuel to another may require a unit to be examined for major NSR permitting requirements. This is true even for modifications required for addition of controls since the modifications could trigger the definition of a “significant modification” under NSR/PSD.

Fuel switching between types and geographic sources of coal and installation of control devices can significantly effect mercury emissions. Data from EPA's Mercury Information Collection Request (ICR) revealed that many power plants have existing mercury capture as a co-benefit of air pollution control technologies for NO_X, SO_2 and PM. This includes capture of particulate-bound mercury in PM control equipment and capture of soluble ionic mercury in wet FGD systems. Additional data have also shown that the use of SCR for NO_X control enhances oxidation of elemental mercury to the soluble ionic form, resulting in increased removal in the wet FGD system for units burning bituminous coal. Overall the ICR data revealed higher levels of Hg capture for bituminous coal-fired plants as compared to subbituminous coal-fired plants. Other factors that influence mercury emissions from coal combustion are chlorine content of the coal and fly ash composition.

FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage. According to Integrated Planning Model (IPM®) background documentation, wet FGD systems reduce the capacity of the EGU by 2.1%. This means that the scrubber reduces the amount of electricity for sale to the grid by 2.1%. The main effect of this reduction is the increased cost of energy production.

The primary environmental impact of FGD systems is the generation of wastewater and sludge from the SO_2 removal process. When the exhaust gas from the boiler enters the FGD the SO_2, metals, and other solids are removed from the exhaust and collected in the FGD liquid. The liquid slurry collects in the bottom of the FGD in a reaction tank. The slurry is then dewatered and a portion of the contaminant-laden water is removed from the system as wastewater. Waste from the FGD systems will increase sulfate, metals, and solids loading in a facility’s wastewater, potentially impacting community wastewater treatment facilities for smaller units that do not have self contained water treatment systems. In some cases FGD operation necessitates installation of a clarifier on site to remove excessive pollutants from wastewater. This places additional burdens on a facility or community wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge must be stabilized prior to land filling. If a calcium sulfate sludge is produced, dewatering alone is necessary before land filling, however, SO_2 removal costs are higher due to increased equipment costs for this type of control system. In some cases calcium sulfate sludge can be sold for use in cement manufacturing.

With wet FGD technologies a significant visible plume is present from the source due to condensation of water vapor as it exits the smoke stack. Although the water eventually evaporates and the plume disappears, community impact may be significant.

Remaining Useful Life of the Source

Available information for remaining useful life estimates of EGU boilers indicates a wide range of operating lifetimes, depending on 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, repowering, 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.

REFERENCES

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CHAPTER 3

ANALYSIS OF SELECTED ELECTRIC GENERATING UNITS (EGUs)

EGU FACILITY CONTROLS

The Vermont Department of Environmental Conservation (VTDEC) used the CALPUFF model to estimate sulfate ion impacts from large EGUs and determine the major EGUs and process units (boilers) at the EGUs that contribute to visibility impairment in Class I MANE-VU areas and Class I areas affected by emissions from sources within MANE-VU (See Chapter 1, for more details). Modeling was based on 2002 SO_2 emissions, and the results of the modeling showed the SO_2 emissions of the 100 highest emitting EGUs and the contribution of these sources toward the SO_2 concentration in each of the Class I areas. Proximity of the individual sources to Class I areas and variations in meteorology on the 20% worst visibility days resulted in varying impacts from individual sources on each Class I area. In subsequent discussions with MARAMA and the Reasonable Progress Workgroup, MACTEC was directed to focus on the emissions from the top 30 individual sources for this analysis. The 30 individual sources are located at 23 distinct facilities. The location of the 23 EGU facilities of interest is included in Figure 3.1.

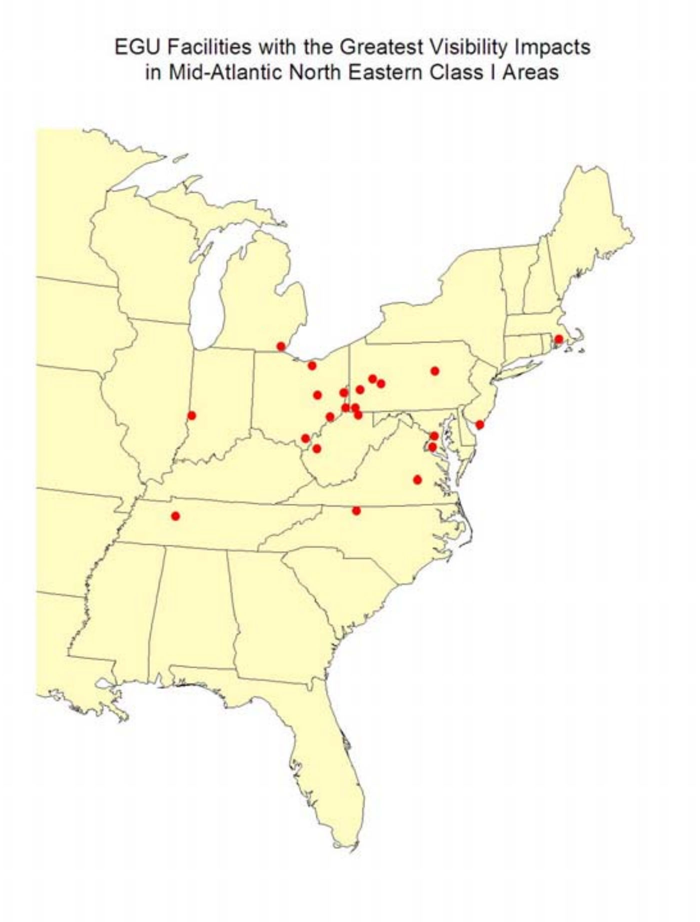
Since EGUs are the largest emitters of SO_2 in the United States and have the greatest impact on haze in the MANE-VU Class I areas, it is particularly useful to determine what controls have recently been applied at these facilities (since the 2002 emission inventory). Also important is information about controls that are currently being applied at facilities, or are planned for addition in the future.

MACTEC gathered information from two primary sources of data for analysis of controls to be applied at the 30 EGUs.

1. Integrated Planning Model (IPM®) results from the MANE-VU CAIR Plus (MARAMA 4c) run.
2. Information from State agencies with facilities in the list of the top 30 individual sources. We requested EGU permit information, information about SO_2 controls recently implemented or planned at the facility and any available information on BART, consent decrees, or other regulations that will impact EGU control devices.

The MANE-VU CAIR Plus model results represent an estimate of the additional controls that might be installed under a more stringent cap and trade program in the Eastern U.S. The comparison of this estimate to the known planned controls for these 30 key EGUs is intended to give an idea of whether a stricter cap would in fact result in great controls at these sources.

Figure 3.1



Note: Some facilities are too close to differentiate on the map

INTEGRATED PLANNING MODEL (IPM®) ANALYSIS

For EGUs, EPA used the Integrated Planning Model (IPM®) to estimate which units will install controls at what costs and which units will buy credits. The RPOs also made some Integrated Planning Model (IPM®) runs to determine which units will install controls to comply with the EPA CAIR rule. Additionally, an even more stringent “CAIR Plus” strategy was investigated using the Integrated Planning Model (IPM®). The parsed results which include modeled control scenarios for individual EGUs were used to help determine costs for EGUs, and ultimately estimate the marginal cost of SO_2 reductions for the model planning years of 2009, 2012, and 2018.

MACTEC obtained information from the CAIR Plus Policy Case, (MARAMA_4c) for the years 2009, 2012, and 2018 for the 30 EGUs. The information obtained included unit design capacity, SO_2 emissions, assumed existing controls, and controls to be applied as calculated by the Integrated Planning Model (IPM®). The information was available for each of the individual years, (2009, 2012, and 2018). Also available were the resulting changes in design capacity due to controls, production output, or other factors from Integrated Planning Model (IPM®). The parsed model data do not supply specific design information pertaining to the scrubber size, costs, or other related information for individual units. It is only possible to determine the year that the scrubber is due to be installed on individual process units. Information from the CAIR Plus Integrated Planning Model (IPM®) run is included in Table 3.1. Integrated Planning Model (IPM®) projections in Table 3.1 are not intended to be interpreted literally, but only as an example of the least-cost results from one set of inputs to the model. Also, the controls applied by Integrated Planning Model (IPM®) may differ from planned controls at the facility. For information on planned controls at these facilities, please see Table 3.2

Table 3.1 Integrated Planning Model (IPM® version 2.1.9) CAIR Plus Projections for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

State	Facility ID	Facility	Primary Emissions Point Descriptions	Point #	2002 SO_2 Total (Tons)[1]	2018 SO_2 Total (Tons)[2]	SO_2 Reduction (2002-2018) (Tons/Year)[3]	% SO_2 Reduction (2002-2018)[3]	Design Capacity[4]	Existing Control[4]	MANE_VU CAIR Plus Projection[5]
TN	D03406C10	Johnsonville	Coal - wall fired; dry bottom boiler	10	108,789	46,000	63,000	58%	15,688 MMBTU	Cold-side ESP; LNB	SCR by 2012
OH	D028404	Conesville	Coal - tangential; dry bottom boiler	4	92,340	7,000	85,000	92%	764 MW	Cold-side ESP; LNB + OFA + BOOS	SCR and Scrubber by 2009
PA	D031361	Keystone	Coal - tangential; dry bottom boiler	1	87,709	5,000	83,000	94%	8,010 MMBTU	Cold-side ESP + SCR; LNB; OFA	Scrubber by 2009
OH	D02872C04	Muskingum River	Coal - cyclone; wet bottom boiler	4	24,484	1,000	23,000	96%	205 MW to 201 MW by 2012	Cold-side ESP; OFA	SCR and Scrubber by 2012
PA	D03179C01	Hatfield's Ferry	Coal - wall fired; dry bottom boiler	1	55,695	13,000	43,000	77%	5,766 MMBTU	Cold-side ESP + SNCR; LNB	None
OH	D02876C01	Kyger Creek	Coal - wall fired; wet bottom boiler	1	13,789	1,000	13,000	93%	13,789 MMBTU	Cold-side ESP + SCR; OFA	Scrubber by 2012
WV	D03935C02	John E. Amos	Coal - wall fired; dry bottom boiler	2	31,465	6,000	25,000	81%	7,020 MMBTU	Cold-side ESP + SCR; LNB	Scrubber
PA	D031362	Keystone	Coal - tangential; dry	2	62,890	4,000	59,000	94%	8,010 MMBTU	Cold-side ESP + SCR; LNB; OFA	Scrubber by 2009
IN	D01010C05	Wabash River	Coal - wall fired; dry bottom boiler	5	9,380	1,000	8,000	89%	95 MW	Cold-side ESP + Cyclone; LNB + OFA	SNCR by 2009
PA	D031491	Montour	Coal - tangential; dry bottom boiler	1	61,005	4,000	57,000	93%	744 MW	Cold-side ESP + SCR; LNB + OFA	Scrubber by 2009
NC	D080421	Belews Creek	Coal - wall fired; dry bottom boiler	1	57,848	3,000	55,000	95%	1,096 MW	Cold-side ESP + SCR; LNB	Mercury control
WV	D03948C02	Mitchell	Coal - wall fired; dry bottom boiler	2	29,532	6,000	24,000	80%	7,020 MMBTU	Cold-side ESP + SCR + Wet Scrubber; LNB	None
PA	D031222	Homer City	Coal - wall fired; dry bottom boiler	2	55,346	3,000	52,000	95%	6,792 MMBTU	Cold-side ESP + SCR; LNB + OFA	Scrubber by 2009
PA	D031492	Montour	Coal - tangential; dry bottom boiler	2	50,441	4,000	46,000	92%	729 MW	Cold-side ESP + SCR; LNB + OFA	Scrubber by 2009
MD	D01571CE2	Chalk Point	Coal - wall fired; dry bottom boiler	2	23,537	2,000	22,000	92%	335 MW	Cold-side ESP; LNB	SCR and Scrubber by 2009
MI	D01733C12	Monroe	Coal - cell fired; dry bottom boilers	1 & 2	48,563	28,000	21,000	42%	770, 785 MW	Cold-side ESP + SCR; LNB	None
PA	D031221	Homer City	Coal - wall fired; dry bottom boiler	1	45,745	3,000	43,000	93%	607 MW	Cold-side ESP + SCR; LNB + OFA	Scrubber by 2009
NC	D080422	Belews Creek	Coal - wall fired; dry bottom boiler	2	45,236	3,000	42,000	93%	1,096 MW	Cold-side ESP + SCR; LNB	Mercury control
WV	D039432	Fort Martin	Coal - wall fired; dry bottom boiler	2	45,890	5,000	41,000	89%	4,634 MMBTU	Cold-side ESP + SNCR; LNB + OFA	Scrubber by 2012
WV	D039431	Fort Martin	Coal - tangential; dry bottom boiler	1	45,228	5,000	40,000	89%	4,460 MMBTU	Cold-side ESP + SNCR; LNB + OFA	Scrubber by 2012
WV	D039353	John E. Amos	Coal - wall fired; dry bottom boiler	3	44,030	9,000	35,000	80%	11,900 MMBTU	Cold-side ESP + SCR; LNB	Scrubber

Table 3.1 Integrated Planning Model (IPM® version 2.1.9) CAIR Plus Projections for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

State	Facility ID	Facility	Primary Emissions Point Descriptions	Point #	2002 SO_2 Total (Tons) [1]	2018 SO_2 Total (Tons) [2]	SO_2 Reduction (2002-2018) (Tons/Year) [3]	% SO_2 Reduction (2002-2018)[3]	Design Capacity[4]	Existing Control[4]	MANE_VU CAIR Plus Projection[5]
OH	D0283612	Avon Lake	Coal - wall fired; dry bottom boiler	12	41,872	6,000	36,000	86%	6,040 MMBTU	Cold-side ESP	Scrubber by 2009; SCR by 2012
VA	D037976	Chesterfield	Coal - tangential; dry bottom boiler	6	40,923	4,000	37,000	90%	6,650 MMBTU	Cold-side ESP; LNB + OFA	SCR and Scrubber by 2012
PA	D082261	Cheswick	Coal - tangential; dry bottom boiler	1	42,018	5,000	37,000	88%	550 MW	Cold-side ESP + SCR ; LNB + OFA	Scrubber by 2009
OH	D028281	Cardinal	Coal - cell fired; dry bottom boilers	1	39,894	2,000	38,000	95%	600 MW to 587 MW in 2012	Cold-side ESP + SCR; LNB	Scrubber by 2012
MD	D015731	Morgantown	Coal - tangential; dry bottom boiler	1	37,757	3,000	35,000	92%	570 MW	Cold-side ESP; LNB +OFA	SCR and Scrubber by 2009
OH	D028667	W H Sammis	Coal - wall fired; dry bottom boiler	7	33,720	3,000	31,000	91%	593 MW to 818 MW in 2012	Cold-side ESP + SNCR; LNB	Scrubber in 2009; Coal to IGCC in 2012
MD	D015732	Morgantown	Coal - tangential; dry bottom boiler	2	32,587	3,000	30,000	91%	570 MW	Cold-side ESP; LNB +OFA	SCR and Scrubber by 2009
MA	D016193	Brayton Point	Coal - wall fired; dry bottom boiler	3	19,451	3,000	16,000	85%	5,800 MMBTU	Cold-side ESP; LNB + OFA	SCR, Scrubber, Mercury Control by 2009
NJ	D023781	B L England	Coal - cyclone; wet bottom boiler	1	10,080	1,000	9,000	90%	129 MW	Cold-side ESP; + SNCR; OFA	None

Note: CEMS hourly data was used in the modeling of the emission units, not annual emissions. Also, a single emission unit at a generating plant may represent two or more emission units at that plant emitting from the same stack point. (Refer to the detailed explanation in the Introduction section of this report).

Table references:

1. 2002 SO_2 total for the emission point from RPO emission inventory
2. Integrated Planning Model (IPM®) CAIR Plus projected 2018 SO_2 total for the emission point (rounded to nearest 1,000 tons)
3. Approximate reduction in SO_2 emissions for 2018 Integrated Planning Model (IPM®) versus 2002 RPO emission inventory (rounded to nearest 1,000 tons)
4. Information from Integrated Planning Model (IPM®) and RPO emission inventories
5. Information from Integrated Planning Model (IPM®) CAIR Plus Scenario

Integrated Planning Model (IPM®) background documentation defines a range of control efficiencies, costs, and applicability based on unit size and coal type. (http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html) Three scrubber control technologies are discussed briefly in Integrated Planning Model (IPM®) background documentation; 1. Limestone Forced Oxidation (LSFO), 2. Magnesium Enhanced Lime (MEL) and 3. Lime Spray Dryer (LSD). Each of the three scrubber control technologies are applicable for distinct unit sizes and coal types, but there is no indication in the parsed Integrated Planning Model (IPM®) results as to which type of scrubber has been applied by the model. All three scrubber technologies are assumed to achieve a SO_2 removal percentage of 90% or greater. The range of various scrubber costs is included in Attachment 1. Depending on boiler size, boiler capacity factor, and coal sulfur content, the fixed capital costs range from $140 to $580/kW, while fixed operation and maintenance costs (O&M) range from $5 to $24/kW-yr and variable O&M costs range from 1.0 to 2.4 mills/kWh. Assuming the typical costs in Attachment 1, an EGU rated 500 MW, (the approximate average of the 30 units included in this analysis), a capital cost investment of $216/kW or $110 million would be expected. Fixed O&M and variable O&M costs would be approximately $11/kW-yr and 2.0 mills/kWh, respectively and would depend on the EGU annual output. This cost could be expected to reduce SO_2 emissions by greater than 90%. A typical SO_2 reduction from a 500 MW unit (assuming a minimum of 90% reduction), based on the 30 units included in this analysis would be from 4,000 to 40,000 tons annually. (Converted from 1999 to 2006 dollars using a conversion factor of 1.2101 www.inflationdata.com)

INFORMATION OBTAINED FROM STATE AGENCIES

The 30 EGUs analyzed here are already subject to a variety of existing emission control requirements, including CAIR, BART, mercury controls, the NO_X SIP call, and EPA's acid rain control program. Therefore, it is expected that at least some of the 30 EGUs will already be adding control by 2018.

To investigate this possibility, MACTEC contacted State agencies with facilities in the list of the top 30 individual sources. We requested EGU permit information, information about SO_2 controls recently implemented or planned at the facility, and any available information on BART, consent decrees, or other regulations that will impact EGU control devices. The information we have obtained is included in Table 3.2.

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Johnsonville[1, 2, 3]	TN	108,789	Coal-fired Boilers 01-10 for steam & electricity generation. The units are pulverized coal, dry-bottom boilers without fly ash reinjection. Units 1-6 are Combustion Engineering tangentially-fired boilers. Units 7-10 are Foster Wheeler wall fired boilers. All boilers exhaust through a common stack.	43-0011-01-10	15,688 MMBTU/hr	ESP	Combustion of low-sulfur fuel (since 2002) SCR by 2018	2018 SO_2 emissions will be approximately 51,000 tpy
Conesville[4]	OH	92,340	Unit 4 Main Boiler - Combustion Engineering model 7868 pulverized coal-fired, dry-bottom boiler	B004	7,960 MMBTU/hr	ESP	FGD and SCR by 8/18/09	N/A
Keystone (aka Reliant Energy Northeast Mgmt/Keystone Power Plant)[5]	PA	87,709	Boiler 1 w/low NO_X burner	1 (031)	8,717 MMBTU/hr	Cold-side ESP SCR	FGD	Alternate operation: SCR System Boiler 1
Muskingum River[6]	OH	24,484	Unit 3 Main Boiler - Babcock and Wilcox model RB-248 (custom) coal-fired, cyclone boiler	B004	2,150 MMBTU/hr	ESP	None planned	N/A

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	**State**	**2002 SO_2 Total (tons)[a]**	**Primary Emissions Point Description**	**Point ID (Permit ID No.)**	**Design Capacity**	**Existing Control(s)**	**Proposed/ Planned Control(s)**	**Additional Information**
Hatfield's Ferry[5]	PA	55,695	Babcock & Wilcox Boiler #1 that burns bituminous coal (227 tons/hr) and No. 2 fuel oil (1,384 gal/hr)	1 (031)	5,766 MMBTU/hr	Cold-side ESP	FGD	N/A
Kyger Creek[6]	OH	13,789	Unit #1 Boiler- Babcock and Wilcox pulverized coal-fired, wet-bottom boiler	B001	1,850 MMBTU/hr	ESP	SCR, FGD operational by 1/01/09	N/A
John E. Amos[7,8]	WV	31,465	Dry-bottom wall-fired coal boiler	2	800 MW, 7,020 MMBTU/hr	ESP Low NO_X burners SCR	FGD (12/2008)	Vents through CS012
Keystone (aka Reliant Energy Northeast Mgmt/Keystone Power Plant)[5]	PA	62,890	Boiler 2 w/low NO_X burner	2 (032)	8,717 MMBTU/hr	Cold-side ESP SCR	FGD	Alternate operation: SCR System Boiler 2
Wabash (aka Duke Energy Indiana, Inc. - Wabash River Generating Station)[9, 10]	IN	9,380	Wall fired coal electric utility boiler (pulverized – dry bottom) constructed in 1956 using No. 2 fuel oil as ignition fuel	5	1,096.2 MMBTU/hr	Low- NO_X burner (NO_X) ESP (PM)	None	Stack is equipped with CEM for SO_2

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	**State**	**2002 SO_2 Total (tons)[a]**	**Primary Emissions Point Description**	**Point ID (Permit ID No.)**	**Design Capacity**	**Existing Control(s)**	**Proposed/ Planned Control(s)**	**Additional Information**
Montour (aka PPL Montour, LLC – Montour Steam Electric Station)[5]	PA	61,005	CE Boiler – Unit #1 that burns bituminous coal and No. 2 fuel oil	1 (031)	7,317 MMBTU/hr	Cold-side ESP SCR	FGD	N/A
Belews Creek (aka Duke Power's Belews Creek Plant)[11]	NC	57,848	Coal-fired electric utility boiler constructed in 1974	1	1,120 MW	None	Scrubbers (2008)	Expected rate under their compliance plan for the Clean Smokestacks Act is 0.150 lbs SO_2/MMBTU. Expected emissions SO_2 for 2013 and later is 5,512 tpy.
Mitchell[7, 12]	WV	29,532	Dry-bottom wall-fired coal boiler	2	800 MW, 7,020 MMBTU/hr	ESP Low NO_X burners	FGD (1/2007); SCR (4/2007)	Vents through CS012
Homer City (aka Homer City OL/Homer City Generation Station[13]	PA	55,346	Boiler No. 2 (Unit 2)	2 (032)	6,792 MMBTU/hr	Cold-side ESP SCR	FGD	N/A
Montour (aka PPL Montour, LLC – Montour Steam Electric Station)[5]	PA	50,441	CE Boiler – Unit #2 that burns bituminous coal and No. 2 fuel oil	2 (032)	1,239 MMBTU/hr	Cold-side ESP SCR	FGD	N/A

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	**State**	**2002 SO_2 Total (tons)[a]**	**Primary Emissions Point Description**	**Point ID (Permit ID No.)**	**Design Capacity**	**Existing Control(s)**	**Proposed/ Planned Control(s)**	**Additional Information**
Chalk Point[15, 16]	MD	23,537	Steam Unit 2 is a wall fired, dry bottom, supercritical boiler base loaded unit. The primary fuel is coal with natural gas and No. 2 oil used for ignition.	2	342 MW	Low NO_X burners ESP SACR LNBs & SOFA (NO_X)	SCR and FGD (2009/2010 timeframe)	Unit covered under the MD Healthy Air Act
Monroe (aka Detroit Edison – Monroe Power Plant)[16]	MI	48,563	4 cell burner boilers (Boiler Unit Nos. 1, 2, 3, and 4) constructed in the late 1960s (1968-1969) and modified in 1994	EG01 EG02 EG03 EG04	3,000 MW (total)	Dry wire ESP (SO_3) FGD (Units 3 & 4) @ 97% CE	May put scrubbers on Units 1 & 2 later	If additional scrubbers are added, a SO_2 reduction of 97% is anticipated
Homer City (aka Homer City OL/Homer City Generation Station[13]	PA	45,745	Boiler No. 1 (Unit 1)	1 (031)	6,792 MMBTU/hr	Cold-side ESP SCR	FGD	N/A
Belews Creek (aka Duke Power's Belews Creek Plant)[11]	NC	45,236	Coal-fired electric utility boiler constructed in 1975	2	1,120 MW	None	Scrubbers (2008)	Expected rate under their compliance plan for the Clean Smokestacks Act is 0.150 lbs SO_2/MMBTU. Expected emissions SO_2 for 2013 and later is 4,639 tpy.

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Fort Martin[7, 8]	WV	45,228	Tangentially-fired coal boiler	1	552 MW, 4,460 MMBTU/hr	ESP Low NO_X burners SNCR Trim	FGD (4Q 2009)	N/A
Fort Martin[7, 8]	WV	45,890	Wall-fired coal boiler	2	55 MW, 4,634 MMBTU/hr	ESP Low NO_X burners SNCR Trim	FGD (1Q 2010)	N/A
John E. Amos[7, 8]	WV	44,030	Dry-bottom wall-fired coal boiler	3	1,300 MW, 11,900 MMBTU/hr	ESP Low NO_X burners SCR	FGD (12/2007)	N/A
Avon Lake[6]	OH	41,872	Boiler #12 - Pulverized coal-fired, dry bottom, boiler	B012	6,040 MMBTU/hr	ESP	SCR and FGD operational by 2010	N/A
Chesterfield (aka Chesterfield Power Station)[17]	VA	40,923	Combustion Engineering tangentially-fired coal boiler equipped with startup burners	6 (ES-6A)	6,650 MMBTU/hr	SCR ESP Stage combustion coal burners	FGD (95% CE under construction, operational 2008)	The unit is restricted to burn 2,330,160 tons/yr of coal at an annual average heating value of 12,500 BTU/lbs
Cheswick (aka Cheswick Power Station)[18]	PA	42,018	Tangentially-fired "main" boiler that burns bituminous coal (primary fuel), natural gas, and synfuel	1	5,500 MMBTU/hr (coal & synfuel) 1,000 MMBTU/hr (NG)	Low NO_X burners SCR ESP w/flue gas conditioning (PM)	FGD (98% CE planned)	N/A

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Cardinal[6, 12]	OH	39,894	Unit 1 Main Boiler - Babcock and Wilcox, pulverized coal-fired, dry bottom, cell burner boiler	B001	527 MMBTU/hr	ESP	FGD (2/2008)	N/A
Morgantown[14, 15]	MD	37,757	Combustion Engineering, Inc., Unit Boiler No. 1 - steam generating coal-fired utility boiler installed in 1967 which primarily combusts Eastern Bituminous coal containing no more than 2% sulfur by weight and secondary fuel is No. 6 oil containing no more than 2% sulfur by weight	1 (F-1)	5,317 MMBTU/hr	ESP SO_3 injection Low NO_X burners	SCR and FGD (2009/2010 timeframe)	Stacks equipped with SO_2, NO_X, CO_2, and ultrasonic flow monitors. Unit covered under the MD Healthy Air Act.
W H Sammis[6]	OH	33,720	Coal Fired Boiler No.1 - Foster-Wheeler pulverized coal-fired, dry-bottom boiler	B007	1,822 MMBTU/hr	Fabric filter	ESP FGD operational 12/31/09 SNCR Operational 06/06	N/A

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Morgantown[14, 15]	MD	32,587	Combustion Engineering, Inc., Unit Boiler No. 2 - steam generating coal-fired utility boiler installed in 1967 primarily combusts Eastern Bituminous coal w/ no more than 2% sulfur by weight and secondary fuel is No. 6 oil w/ no more than 2% sulfur by weight	1 (F-2)	5,317 MMBTU/hr	ESP SO_3 injection Low NO_X burners	SCR and FGD (2009/2010 timeframe)	Stacks equipped with SO_2, NO_X, CO_2, and ultrasonic flow monitors. Unit covered under the MD Healthy Air Act.
Brayton Point[19]	MA	19,451	Water tube boiler	3 (EU3)	5,655 MMBTU/hr	ESP w/flue gas conditioning (PCD-3)	Fuel sulfur content (2011) FGD (2011)	BART recommended controls for SO_2 are 95% control or 0.15 lb/MMBTU (coal), 0.33 lb/MMBTU (0.3% fuel sulfur limit) (oil)
B L England[20, 21]	NJ	10,080	Wet-bottom, cyclone coal boiler	1	129 MW	ESP SNCR	None	The facility will either close by 2012 or install scrubbers on all coal-fired units. One scrubber is already installed and the other unit would get a 95% CE –minimum, but unclear if this unit is already controlled.

[a] 2002 SO_2 total for the emission point from RPO emission inventory.

[1] Tennessee Department of Environment and Conservation, Division of Air Pollution Control. Personal communication regarding Johnsonville facility from Ms. Julie Aslinger (615-532-0587, Julie.Aslinger@state.tn.us) via E-mail on March 1, 2007.

[2] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comment regarding Johnsonville facility received from Ms. Julie Aslinger (615-532-0587, Julie.Aslinger@state.tn.us) via E-mail on March 30, 2007.

[3] MACTEC, Inc., "Documentation of the Base G 2002 Base Year, 2009 and 2018 Emission Inventories for VISTAS", January, 2007.

[4] Ohio Environmental Protection Agency, Division of Air Pollution Control. Personal communications regarding Conesville facility from Mr. William Spires (614-644-3618, bill.spires@epa.state.oh.us) via E-mail on February 20 and 21, 2007.

[5] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding Keystone, Hatfield's Ferry, and Montour facilities from Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) via E-mail on January 31 and February 7, 2007.

[6] Ohio Environmental Protection Agency, Division of Air Pollution Control. Personal communication regarding Muskingum, Kyger Creek, Avon Lake, Cardinal, and WH Sammis facilities from Mr. William Spires (614-644-3618, bill.spires@epa.state.oh.us) via E-mail on February 20, 2007.

[7] West Virginia Division of Air Quality. Personal communication regarding John. E. Amos, Mitchell, and Fort Martin facilities from Ms. Laura Crowder (304-926-0499 Ext. 1247, LCROWDER@wvdep.org) via E-mail on February 17, 2007.

[8] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding John E. Amos, Mitchell, and Fort Martin and facilities received from Ms. Laura Crowder (304-926-0499 Ext. 1247, LCROWDER@wvdep.org) via E-mail on March 30, 2007.

[9] Indiana Department of Environmental Management, Office of Air Quality. Personal communication regarding Wabash facility between Mr. Jay Koch (317-233-0581, JKOCH@idem.IN.gov) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[10] Indiana Department of Environmental Management, Office of Air Quality. Personal communications regarding Wabash facility from Mr. Jay Koch (317-233-0581, JKOCH@idem.IN.gov) via E-mail on February 1 and 5, 2007.

[11] North Carolina Department of Environment and Natural Resources, Division of Air Quality. Personal communications regarding Belews Creek facility from Ms. Sheila Holman (919-715-0971, shelia.holman@ncmail.net) via E-mail on February 1 and 2, 2007.

[12] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding Mitchell and Cardinal facilities received from Mr. David J. Long, P.E. of American Electric Power (614-716-1245, djlong@aep.com) via E-mail on March 29, 2007.

[13] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding Homer City facility from Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) via E-mail on January 31 and February 7 and 8, 2007.

[14] Maryland Department of the Environment. Personal communication regarding Chalk Point and Morgantown facilities from Mr. Andy Heltibridle (410-537-4218, aheltibridle@mde.state.md.us) via U.S. mail on February 9, 2007.

[15] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding Chalk Point and Morgantown facilities received from Mr. Brian Hug (410-537-4125, bhug@mde.state.md.us) via E-mail on March 14, 2007.

[16] Michigan Department of Environmental Quality, Air Quality Division. Personal communication regarding Monroe facility from Ms. Teresa Walker (517-335-2247, walkertr@michigan.gov) via E-mail on February 7, 2007.

[17] Virginia Department of Environmental Quality, Division of Air Quality. Personal communication regarding Chesterfield facility from Ms. Doris McLeod (504-698-4197, damcleod@deq.virginia.gov) via E-mail on February 9, 2007.

[18] Allegheny County Health Department. Personal communications regarding Cheswick facility from Ms. Jayme Graham (412-578-8129, JGraham@achd.net) via E-mail on February 2, 2007.

[19] Massachusetts Department of Environmental Protection. Personal communications regarding Brayton Point facility from Mr. Donald Squires (617-292-5618, Donald.Squires@state.ma.us) via E-mail on February 2 and 7, 2007.

[20] New Jersey Department of Environmental Protection, Division of Air Quality. Personal communications regarding B.L. England facility between Mr. Ray Papalski (609-633-7225, Ray.Papalski@dep.state.nj.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[21] New Jersey Department of Environmental Protection, Division of Air Quality. Personal communications regarding B.L. England facility from Mr. Ray Papalski (609-633-7225, Ray.Papalski@dep.state.nj.us) via E-mail on February 1, 2007.

Table 3.3 presents a side by side comparison of the predicted control information from Tables 3.1 and 3.2. The existing control information available from Integrated Planning Model (IPM®) data was in disagreement with the information reported by the States for many of the EGUs. Since controls at the EGUs may have changed recently [since Integrated Planning Model (IPM® v.2.1.9)], Table 3.3 reports existing control information obtained from the States for this report. The information on proposed or planned controls obtained from the States reflects that 26 of the 30 EGUs included in this study plan to install SO_2 control (FGD/scrubber), or switch to a lower sulfur coal prior to 2018. SO_2 reduction estimates from the States were only available for some of the EGUs, but reflect a significant reduction in SO_2 for those units for which an estimate was supplied.

Regarding the control information from Integrated Planning Model (IPM®) CAIR Plus results, Integrated Planning Model (IPM®) predicts that 21 of the 30 EGUs will install SO_2 in the CAIR Plus scenario. Additionally, Integrated Planning Model (IPM®) predicts a reduction in SO_2 at all 30 EGUs included in this study, including the 9 units for which no SO_2 control is added. The SO_2 reductions estimated by Integrated Planning Model (IPM®) are said to be achieved through a number of compliance strategies in addition to control, such as fuel switching, plant retirements, plant dispatch, and new builds. Additional information on all Integrated Planning Model (IPM®) compliance strategies and well as information on NO_X reductions are available in Integrated Planning Model (IPM®) documentation available on EPA's website and in the ICF report titled: *Final Draft Report – Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®).*

Table 3.3 Comparison of Controls Predicted by Integrated Planning Model (IPM®) CAIR Plus Results versus Proposed/Planned Control Additions by the State/Facility (by 2018) at the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	**State**	**Point #**	**2002 SO_2 (tons)**	**Existing Controls (based on information from State)**	**Facility/State Proposed/Planned Controls {% SO_2 reduction}**	**IPM® Predicted Controls (CAIR Plus) {% SO_2 reduction}**
Johnsonville	TN	10	108,789	ESP	Low sulfur fuel since 2002; SCR by 2018 {53% reduction in SO_2}	SCR by 2012 {58% reduction in SO_2}
Conesville	OH	4	92,340	ESP	FGD and SCR by 8/18/09 {SO_2 reduction unavailable}	SCR and Scrubber by 2009 {92% reduction in SO_2}
Keystone	PA	1	87,709	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {94% reduction in SO_2}
Muskingum River	OH	4	24,484	ESP	None planned {SO_2 reduction assumed 0%}	SCR and Scrubber by 2012 {96% reduction in SO_2}
Hatfield's Ferry	PA	1	55,695	Cold-side ESP	FGD {SO_2 reduction unavailable}	None {77% reduction in SO_2}
Kyger Creek	OH	1	13,789	ESP	SCR, FGD operational by 1/01/09 {SO_2 reduction unavailable}	Scrubber by 2012 {93% reduction in SO_2}
John E. Amos	WV	2	31,465	ESP; Low NO_X burners; SCR	FGD by 12/2008 {SO_2 reduction unavailable}	Scrubber {81% reduction in SO_2}

Table 3.3 Comparison of Controls Predicted by Integrated Planning Model (IPM®) CAIR Plus Results versus Proposed/Planned Control Additions by the State/Facility (by 2018) at the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	Point #	2002 SO_2 (tons)	Existing Controls (based on information from State)	Facility/State Proposed/Planned Controls {% SO_2 reduction}	IPM® Predicted Controls (CAIR Plus) {% SO_2 reduction}
Keystone	PA	2	62,890	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {94% reduction in SO_2}
Wabash River	IN	5	9,380	Low NOX burners; ESP	None planned {SO_2 reduction assumed 0%}	SNCR by 2009 {89% reduction in SO_2}
Montour	PA	1	61,005	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {93% reduction in SO_2}
Belews Creek	NC	1	57,848	None	Scrubbers (2008) {90% reduction in SO_2}	Mercury control {95% reduction in SO_2}
Mitchell	WV	2	29,532	ESP; Low NO_X burners	FGD (1/2007); SCR (4/2007) {SO_2 reduction unavailable}	None {80% reduction in SO_2}
Homer City	PA	2	55,346	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {95% reduction in SO_2}
Montour	PA	2	50,441	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {92% reduction in SO_2}
Chalk Point	MD	2	23,537	Low NO_X burners; ESP; SACR LNBs & SOFA	SCR and FGD (2009/2010 timeframe) {SO_2 reduction unavailable}	SCR and Scrubber by 2009 {92% reduction in SO_2}
Monroe	MI	1 & 2	48,563	Dry wire ESP; FGD	Possible addition of scrubbers {97% SO_2 reduction if controlled}	None {42% reduction in SO_2}
Homer City	PA	1	45,745	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {93% reduction in SO_2}
Belews Creek	NC	2	45,236	None	Scrubbers (2008) {90% reduction in SO_2 }	Mercury control {93% reduction in SO_2}
Fort Martin	WV	2	45,890	ESP, Low NO_X burners; SNCR Trim	FGD (4Q 2009) {SO_2 reduction unavailable}	Scrubber by 2012 {89% reduction in SO_2}
Fort Martin	WV	1	45,228	ESP, Low NO_X burners; SNCR Trim	FGD (1Q 2010) {SO_2 reduction unavailable}	Scrubber by 2012 {89% reduction in SO_2}
John E. Amos	WV	3	44,030	ESP, Low NO_X burners; SCR	FGD (12/2007) {SO_2 reduction unavailable}	Scrubber {80% reduction in SO_2}
Avon Lake	OH	12	41,872	ESP	SCR and FGD operational by 2010 {SO_2 reduction unavailable}	Scrubber by 2009; SCR by 2012 {86% reduction in SO_2}
Chesterfield	VA	6	40,923	SCR; ESP; Stage combustion burners	FGD operational 2008 {95% reduction in SO_2}	SCR and Scrubber by 2012 {90% reduction in SO_2}
Cheswick	PA	1	42,018	Low NOX burners; SCR; ESP w/flue gas conditioning	None {SO_2 reduction assumed 0%}	Scrubber by 2009 {88% reduction in SO_2}
Cardinal	OH	1	39,894	ESP	FGD (2/2008) {SO_2 reduction unavailable}	Scrubber by 2012 {95% reduction in SO_2}

Table 3.3 Comparison of Controls Predicted by Integrated Planning Model (IPM®) CAIR Plus Results versus Proposed/Planned Control Additions by the State/Facility (by 2018) at the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	Point #	2002 SO_2 (tons)	Existing Controls (based on information from State)	Facility/State Proposed/Planned Controls {% SO_2 reduction}	IPM® Predicted Controls (CAIR Plus) {% SO_2 reduction}
Morgantown	MD	1	37,757	ESP; SO_3 injection; Low NO_X burners	SCR and FGD (2009/2010 timeframe) {SO_2 reduction unavailable}	SCR and Scrubber by 2009 {92% reduction in SO_2}
W H Sammis	OH	7	33,720	Fabric filter	ESP and FGD operational 12/31/09; SNCR operational 6/06 {SO_2 reduction unavailable}	Scrubber in 2009; Coal to IGCC in 2012 {91% reduction in SO_2}
Morgantown	MD	2	32,587	ESP; SO_3 injection; Low NO_X burners	SCR and FGD (2009/2010 timeframe) {SO_2 reduction unavailable}	SCR and Scrubber by 2009 {91% reduction in SO_2}
Brayton Point	MA	3	19,451	ESP w/flue gas conditioning (PCD-3)	Fuel sulfur content (2011); FGD 2011 {95% reduction in SO_2}	SCR, Scrubber, Mercury Control by 2009 {85% reduction in SO_2}
B L England	NJ	1	10,080	ESP;SNCR	Facility will either close or install scrubbers by 2012 {95% reduction in SO_2}	None {90% reduction in SO_2}

Table Reference: See full reference information for Integrated Planning Model (IPM®) and State agency contacts associated with Tables 3.1 and 3.2.

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Energy Information Administration (EIA). Information located on website: http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html

World Bank Organization. Information located on website: http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/aqsocc.stm

Attachment 1. Illustrative Scrubber Costs (1999 $) for Representative MW and Heat Rates under the Assumptions in EPA Base Case 2004

Scrubber Type	Capacity (MW)	Heat Rate (BTU/kWh)			Cost
		9,000	10,000	11,000	
LSFO Min. Cutoff: >= 100 MW Max. Cutoff: None Assuming 3.0% Sulfur Content Coal (by weight) with Heating Value of 11,900 BTU/lb	100	456	469	481	Cap.Cost ($/kW)
		19	19	20	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
	300	225	234	243	Cap.Cost ($/kW)
		11	11	20	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
	500	173	180	187	Cap.Cost ($/kW)
		9	9	9	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
	700	142	149	155	Cap.Cost ($/kW)
		8	8	8	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
	1,000	157	166	174	Cap.Cost ($/kW)
		7	8	8	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
MEL Min. Cutoff: >= 100 MW Max. Cutoff: <500 MW Assuming 1.5% Sulfur Content Coal (by weight) with Heating Value of 11,900 BTU/lb	100	340	351	362	Cap.Cost ($/kW)
		17	17	17	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
	200	224	233	241	Cap.Cost ($/kW)
		12	12	12	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
	300	224	235	245	Cap.Cost ($/kW)
		11	11	12	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
	400	200	210	220	Cap.Cost ($/kW)
		10	10	10	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
	500	178	187	196	Cap.Cost ($/kW)
		9	9	9	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
LSD Min. Cutoff: >= 550 MW Max. Cutoff: None Assuming 1.5% Sulfur Content Coal (by weight) with Heating Value of 11,900 BTU/lb	600	137	144	151	Cap.Cost ($/kW)
		5	5	6	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh
	700	127	134	140	Cap.Cost ($/kW)
		5	5	5	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh
	800	124	130	135	Cap.Cost ($/kW)
		5	5	5	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh
	900	125	131	137	Cap.Cost ($/kW)
		4	4	4	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh
	1,000	118	124	130	Cap.Cost ($/kW)
		4	4	4	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh

Table reference:Copy of Table 5.3 from EPA Integrated Planning Model (IPM®) documentation (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/bc5emission.pdf). (Note: To adjust cost data from 1999 to 2006, multiply by 1.2101 www.inflationdata.com

Attachment 2. Engineering Methodology Used to Calculate $/ton Pollutant Reduction

Calculation of Cost per ton of SO2 of scrubbing

First, calculate annual cost of a scrubber ($/kW/yr)

Cost data

	Cap	Fix O&M	Var O&M		
	469	19	1.7		
	$/Kw	$/KW-yr	$/kWh		
Assume	Cap Rec Factor		CapacFact		
	0.15		0.85		
	1/yr		dimensionless		
			8760 h/yr		
				TOTAL	
Implies	70.35	19	12.6582	**102.01**	*This is the annual cost per kW for a scrubber*
	$/KW-yr	$/KW-yr	$/KW-yr	$/KW-yr	

Then calculation annual emissions reduction from the scrubber

Calculate emissions rate (lb/MBTU) based on coal S content

Fraction S	SO2/S		Heat Content		SO2 Emissions rate
3%	2	divided by	0.012	=	5
dimensls	dimesnlss		MBTU/lb		lb/MBTU

Use emissions rate and assumed plant efficiency/operating hours to get emissions/kw/yr

UnconSO2	Reduction	Heat Rate	Cap Factor	Hr/yr	tons/lb		
5	0.9	0.01	0.85	8760	0.0005	=	**0.167535**
lb/MBTU	dimensionl	MBTU/kWh	dimensls	hr/yr	tons/lb		tons/kw-yr

Check of units:

~~lb~~	~~mbtu~~	~~hr~~	ton
~~mbtu~~	kW -~~hr~~	yr	~~lb~~

Result: Get $/ton of reduction

divide cost/kw/yr by ton/kw/yr =	**608.877**	=	102.01	divided by	0.167535
			$/KW-yr		tons/kw-yr

CHAPTER 4

SOURCE CATEGORY ANALYSIS: INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

SOURCE CATEGORY DESCRIPTION

The MANE-VU contribution assessment has demonstrated that SO_2 emissions are the principal contributor to visibility impairment in Class I areas in the northeast. After electric generation units, Industrial, Commercial, and Institutional (ICI) boilers and heaters are the next largest class of pollution sources that contribute to SO_2 emissions. Typical industrial applications include chemical, refining, manufacturing, metals, paper, petroleum, food production and a wide variety of other small industries and commercial heating applications. Commercial and institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities. Most commercial and institutional boilers are small, with 80% of the population smaller than 15 million British Thermal Units per hour (MMBTU/hr). A fairly wide range of fuels are used by ICI boilers, ranging from coal, petroleum coke, distillate and residual fuel oils, natural gas, wood waste or other class of waste products. Boilers aggregated under the ICI classification are generally smaller than boilers in the electric power industry, and typically have a heat input in the 10 to 250 MMBTU/hr range; however, industrial boilers can be as large as 1,000 MMBTU/hr or as small as 0.5 MMBTU/hour.

The process that a particular unit serves strongly influences the boiler fuel choice. For example, the iron and steel industry uses coal to generate blast furnace gas or coke oven gas that is used in boilers, resulting in sulfur emissions. Pulp and paper processing may use biomass as a fuel, resulting in high PM emissions. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category. While many boilers are capable of co-firing liquid or gaseous fuels in conjunction with solid fuels, boilers are usually designed for optimum combustion of a single specific, fuel. Changes to the fuel type may, therefore, reduce the capacity, duty cycle, or efficiency of the boiler.

Boiler design also plays a role in the uncontrolled emission rate. Most ICI boilers are of three basic designs: water tube, fire tube, or cast iron. The fuel-firing configuration is a second major identifier of boiler design for solid fuels. Stoker boilers are the oldest technology and are still widely used for solid-fueled boilers. Pulverized coal boilers succeeded stokers as a more efficient method of burning coal and are used in larger boiler designs. Circulating fluidized bed (CFB) boilers are the most recent type of boiler for solid fuel combustion and are becoming more commonplace. CFB boilers are capable of burning a variety of fuels, and are more efficient and less polluting than stoker or pulverized coal boilers. Combined heat and power (CHP) or cogeneration technologies are also used to produce electricity and steam or hot water from a single unit. Some ICI boilers are used only in the colder months for space heating, while others have high capacity utilization year round.

Clean Air Act Regulations Controlling ICI Boilers

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. Each of these regulatory programs is discussed in the following paragraphs. Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements includes Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on the locale's degree of non-attainment with ambient air standards.

Title I also imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. In 1986, EPA codified the NSPS for industrial boilers (40 CFR part 60, subparts Db and Dc) and revised portions of them in 1998 to reflect improvements in control methods for the reduction of NO_X emissions. Subpart Db applies to fossil fuel-fired ICI units greater than 100 MMBTU per hour that were constructed or modified after June 19, 1984. Subpart Dc applies to fossil fuel-fired ICI units from 10 to 100 MMBTU per hour that were constructed or modified after June 9, 1989.

In addition, Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency (known as New Source Review, or NSR). NSR prescribes control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in non attainment areas. Control strategies that constitute BACT and LAER evolve over time and are reviewed on a case by case basis in State permitting proceedings.

On September 13, 2004, EPA published a final rule under Title III of the CAA to substantially reduce emissions of toxic air pollutants from ICI boilers. These Maximum Achievable Control Technology (MACT) standards apply to ICI boilers located at major sources of hazardous air pollutants (HAPs). There are many options for complying with the MACT standards, ranging from continued use of existing control systems to fuel switching to the installation of a fabric filter and wet scrubber technologies. Thus, the control technologies used to reduce the level of HAP emitted from affected sources are also expected to reduce emissions of PM, and to a lesser extent, SO_2 emissions.

Title IV of the CAA addresses acid rain by focusing primarily on power plant emissions of SO_2. Title IV includes an Opt-in Program that allows sources not required to participate in the Acid Rain Program the opportunity to enter the program on a voluntary basis and receive their own acid rain allowances. The Opt-in Program offers sources such as ICI boilers a financial incentive to voluntarily reduce its SO_2 emissions. By reducing emissions below allowance allocation, an opt-in source will have unused allowances, which it can sell in the SO_2 allowance market.

The regulation of ICI boilers by various CAA programs has resulted in a variety of unit level emission limits resulting from SIP, NSPS, NSR, or MACT 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.

EVALUATION OF CONTROL OPTIONS

An undesirable by-product of the combustion of sulfur, SO_2 is associated with the combustion of most fossil fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8% or more. Distillate oils typically have sulfur contents less than 0.5% while residual oil can have 1-2% sulfur by weight. Petroleum coke, a byproduct of the oil refining process, may have as much as 6% sulfur. Pipeline quality natural gas contains virtually no sulfur, while landfill gas may contain varying amounts of sulfur depending on the materials contained in the landfill. A variety of air pollution control technologies are employed to meet requirements for sulfur dioxide control and are dependant on a number of factors to determine which technique is utilized for a given facility.

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 this evaluation is 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 should be considered as part of a longer-term solution.

Control techniques may be classified into three broad categories: fuel treatment/substitution, combustion modification, and post-combustion control. Fuel treatment primarily reduces SO_2 and includes coal cleaning using physical, chemical, or biological processes. Fuel substitution involves burning a cleaner fuel or renewable fuel. Combustion modification includes any physical or operational change in the furnace or boiler and is sometimes discussed in conjunction with post-combustion control technologies. Post-combustion control employs a device after the combustion of the fuel and is applied to control emissions of SO_2. It should be noted that physical or operational changes to a furnace or boiler may require that the unit be examined for applicability under the Prevention of Significant Deterioration (PSD) program.

There are a wide variety of proven control technologies for reducing SO_2 emissions from ICI boilers. The method of SO_2 control appropriate for any individual ICI boiler is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost effective emissions reduction technologies for SO_2 are available and are effective in reducing emissions from the exhaust gas stream of ICI boilers.

Effective post-combustion SO_2 controls for boilers, and particularly coal-fired boilers, are well understood and have been applied to a number of sources over the years in response to regulations in the form of NSPS, PSD/NSR, State RACT Rules and the Title IV SO_2 program. Additional SO_2 reductions are anticipated as a result of regional pollution control initiatives prompted by the Clean Air Interstate Rule (CAIR), which was passed on May 12, 2005.

In addition to post-combustion controls that can be applied to reduce emissions of SO_2 from fossil fuel fired boilers, there are other strategies that can be used to reduce emissions of SO_2.

Examples of such strategies include switching to a fuel with a lower sulfur content, or coal cleaning prior to combustion. Methods of SO_2 control applicable to ICI boilers are listed in Table 4.1 with a brief description of the control option, applicability, and range of performance. After the table, a more detailed description of the control option and an analysis of the four factor assessment for reasonable progress is presented.

SO_2 Control Option Descriptions

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 fuel switching and, more significantly, in fluidized bed boilers, in which limestone is added to the fuel in the combustion chamber.

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 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. Descriptions of available SO_2 control technology options are in Table 4.1. A brief discussion of these techniques follows.

Table 4.1 Available SO_2 Control Options For ICI Boilers

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

Table references:
1. *Assessment of Control Technology Options for BART-Eligible Sources*, NESCAUM, March 2005.
2. *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, March 2006.

Switch to Coal with Lower Sulfur Content

Switching from a high sulfur fuel to one with sufficiently low sulfur content is the first option available for SO_2 reduction in this category for pre-combustion control of SO_2. Fuels naturally low in sulfur content are readily available for solid (coal) and liquid (oil) fired boilers. For coal-fired boilers, low-sulfur fuels may be obtained directly or, 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 fuel may not be a technically feasible or economically practical SO_2 control alternative for all boilers. In some cases, a fuel with the required sulfur content to meet the applicable emission reduction may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a fuel is available, use of the lower-sulfur fuel that must be transported long distances from the supplier may not be cost competitive with burning higher sulfur fuel supplied by near-by suppliers and using a post-combustion control device. The feasibility of fuel switching depends partly on the characteristics of the plant and the particular type of fuel change being considered. Many plants will be able to switch from high-sulfur to low-sulfur bituminous coal without serious difficulty, but switching from bituminous to sub-bituminous coal may present greater challenges and costs. In some instances, fuel switching will require significant investment and modifications to an existing plant. Switching to a lower sulfur fuel, either coal or oil, can affect fuel handling systems, boiler performance, PM control effectiveness and ash handling systems. Overall SO_2 reductions estimated from switching to low-sulfur fuels range from 50-80%.

Switch to Natural Gas

Switching from coal combustion to natural gas combustion virtually eliminates SO_2 emissions. It is technically feasible to switch from coal to natural gas, but it is currently uneconomical to consider this option for large ICIs due to the fuel quantity necessary and the price of natural gas. The price of natural gas is roughly seven times the price of coal in terms of heating value.

Reduced Sulfur Oil

Oil-fired boilers may opt for lower sulfur distillate fuels or, if available, ultra-low sulfur distillate fuel. Number 2 distillate fuel oil, heating oil, and highway diesel fuel oil are the same refinery-produced liquid, and are only differentiated for tax purposes. This differentiation is accomplished through addition of a red dye in the fuels supplied for non-transportation related use. Currently, the sulfur content in Number 2 oil varies between 15 and 20,000 ppm. Beginning in 2006, the permissible level of sulfur in highway diesel fuel (ultra low sulfur diesel, or ULSD) was reduced to15 ppm. Prior to that, highway low sulfur diesel fuel was refined to contain 500 ppm sulfur (Low Sulfur Diesel, or LSD). Consequently, refineries have already performed the capital investments required for the production of LSD and ULSD fuel oil. Based on EIA data for the week of Feb 23, 2007 domestic production of ULSD fuel oil accounted for about 45% of all distillate oil in the United States and LSD fuel oil accounted for slightly over 17% of domestic production (See Chapter 8).

Coal Cleaning

According to the 2006 STAPPA-ALAPCO document on control technologies titled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*, coal cleaning or washing is a widely practiced method of reducing impurities in coal, particularly sulfur. Reducing the sulfur content of the fuel used in the boiler reduces the SO_2 emissions proportionally. Coal cleaning has been shown to reduce SO_2 emissions by 20-25%, while increasing the heating value of the fuel. Additional removal can be achieved through advanced chemical washing techniques, but no detailed information on these techniques was available.

Conventional (physical) coal washing techniques remove ash and sulfur from coal by crushing the fuel and separating the components in a liquid bath, such as water. The lighter coal particles float to the top of the bath for recovery, while the heavier impurities sink to the bottom for removal.

Although there are benefits associated with coal washing, there are limitations associated with this technology. The 20-25% SO_2 reduction is beneficial, but post-combustion controls have been shown to reduce SO_2 emissions by greater percentages. Also, solid and liquid wastes are generated using the washing process and must be addressed.

Combustion Control

SO_2 reduction is also possible through combustion related control technologies. One such technology that has been demonstrated and is currently available is the use of fluidized bed boilers.

Fluidized bed boilers generally operate at lower temperatures than other combustion systems, 800° to 870° C (1500° F to 1600° 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° C (1500° 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 up to 90% 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.

Flue Gas Desulfurization (FGD)

There are three types of FGD scrubbers: wet, spray dry, and dry. According to the 2006 STAPPA-ALAPCO document on control technologies titled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*, EPA reports that 85% of the FGD systems in use in the United States are wet systems. Twelve percent of the FGD systems are spray dry systems, and 3% are dry systems. The operating parameters, efficiency, and costs of each SO_2 removal method are different.

SO_2 in the 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”. Most wet FGD systems for control of SO_2 emissions 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 used by a small 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 hemi-hydrate 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 disposal of large quantities of waste sludge.

The SO_2 removal efficiencies of existing wet limestone scrubbers range from 31-97%, with an average of 78%. The SO_2 removal efficiencies of existing wet lime scrubbers range from 30 to 95%. 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.

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 60-95%.

For the dry injection process, dry powdered lime (or another suitable sorbent such as trona) 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%.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR ICI BOILERS

Each of the control options presented in Table 4.1 is reviewed in this section utilizing a four factor analysis approach for determining reasonable progress as required by Section 169A(g)(1) of the Clean Air Act and Section 51.308(d)(1)(i)(A). The information provided in this section is intended to be used by the States in setting Reasonable Progress Goals (RPGs) for reducing regional haze in Class I areas in MANE-VU Class I areas.

Cost of Compliance

To compare the various control options, information has been compiled on the cost-effectiveness of retrofitting controls. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases.

Cost of Switching to Low Sulfur Coal, Distillate Oil, or Natural Gas

Switching to a low-sulfur coal or blending a lower sulfur coal can impact cost due to the following two main reasons:

1. The cost of low-sulfur coal compared to higher sulfur coal.
2. The cost of boiler or coal handling equipment modifications necessary

The cost of low-sulfur coal compared to higher sulfur coal is not only related to the “dollar per ton” cost of the coal, but the heating value of the coal also impacts the cost analysis.

Table 4.2 reflects the potential sulfur reduction possible by switching fuels:

Table 4.3 shows the average 2004 and 2005 cost data from the Energy Information Administration for various fuels.

Refineries were required to make significant capital investments to meet the LSD and ULSD highway fuel sulfur requirement. To achieve the LSD and ULSD sulfur goals, refineries were required to implement diesel desulfurization technologies. Estimates for the capital costs were developed in 2001 by the Energy Information Administration (EIA) and are based on calendar year 1999. Table 4.4 presents the capital costs for desulfurization technologies presented by the EIA. The EIA developed estimates for new and revamped desulfurization technologies at existing refineries.

Table 4.2 Potential SO_2 Reductions Through Fuel Switching

Original Fuel	Sub-bituminous Coal (% Reduction)	Distillate oil (% Reduction)	Natural Gas (% Reduction)
Bituminous Coal	72.9	91.2	99.9
Sub-bituminous coal	-	69.5	99.9
Residual Oil	-	91.5	99.9
Distillate Oil	-	-	99.7

Calculations based on typical fuel sulfur content listed in Department of Energy EIA analysis for 2000. *Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation*

In its highway diesel fuel rulemaking, EPA also developed cost estimates for the deployment and implementation of desulfurization technologies at refineries. EPA estimated that it would cost existing refineries an estimated $50 million per refinery to install desulfurization technologies. No estimates were made for the costs associated with new refineries as none are currently being constructed in the United States. The EPA analysis spread the investment cost over a 2-year period. Consequently, it was estimated that the US refinery-wide investment for calendar year 2004 was $2.45 billion and $2.83 billion for calendar year 2005 (EIA 2001) (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383 www.inflationdata.com).

Using the most recently available EIA price information for 2006 No. 2 Distillate oil for industrial, commercial, and institutional facilities in the northeast (excluding taxes), a cost per ton of SO_2 removed was calculated to be $734/ton SO_2 by switching to 500 ppm LSD and $554/ton SO_2 by switching to ULSD fuel oils. (See the discussion of fuel oil prices in Chapter 7 – Heating Oil.)

Cost of Coal Cleaning

The World Bank, an organization which assists with economic and technological needs in developing countries reports that the cost of physically cleaning coal varies from $1 to $10 per ton of coal cleaned, depending on the coal quality, the cleaning process used, and the degree of cleaning desired. In most cases the costs were found to be between $1 and $5 per ton of coal cleaned.

Cost of Combustion Control

Dry sorbent injection, (DSI), systems have lower capital and operation costs than post-combustion FGD systems due to: simplicity of design, lower water use requirements, and smaller land use requirements. Table 4.3 presents the estimated costs of adding DSI based SO_2 controls to ICI boilers based on boiler size, fuel type, and capacity factor. Capacity factor is the amount of energy a boiler generates in one year divided by the total amount it could generate if it ran at full capacity.

Table 4.3 Estimated Dry Sorbent Injection (DSI) Costs For ICI Boilers (2006 dollars)

Fuel	SO_2 Reduction (%)	Capacity Factor (%)	Cost Effectiveness ($/Ton of SO_2)		
			100 MMBTU/hr	250 MMBTU/hr	1,000 MMBTU/hr
2%-sulfur coal	40	14	4,686	3793	2,979
		50	1,312	1062	834
		83	772	624	490
3.43%-sulfur coal	40	14	2,732	2,212	1,737
		50	765	619	486
		83	450	364	286
2%-sulfur coal	85	14	2,205	1,786	1,402
		50	617	500	392
		83	363	294	231
3.43%-sulfur coal	85	14	1,286	1,040	818
		50	360	291	229
		83	212	171	134

Calculations based on information available from EPA Publications, EPA-452/F-03-034, *Air Pollution Control Technology Fact Sheet*, and EPA-600/R-05-034, *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*
(Converted from 2005 to 2006 dollars using a conversion factor of 1.0322 www.inflationdata.com)

Cost of FGD

Installation of post-combustion SO_2 control in the form of FGD has several impacts on facility operation, maintenance, and waste handling. FGD systems typically require significant area for construction of the absorber towers, sorbent tanks, and waste handling. The facility costs are, therefore, variable and dependent on the availability of space for construction of the FGD system. Solid waste handling is another factor that influences the cost of FGD control systems. Significant waste material may be generated that requires disposal. This cost may be mitigated, however, by utilization of a forced oxidation FGD process that produces commercial quality gypsum, which may be sold as a raw material for other commercial processes.

Table 4.4 presents the total estimated cost effectiveness of adding FGD based SO_2 controls to ICI boilers based on boiler size, fuel type, and capacity factor. There is no indication that these cost data include revenue from gypsum sales. Revenue from gypsum sales would reduce the cost of these controls.

Table 4.4 Estimated Flue Gas Desulfurization (FGD) Costs For ICI Boilers (2006 dollars)

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

a. Assumes sulfur content = 3.43% and ash content = 12.71%.
b. Assumes sulfur content = 2.0% and ash content = 13.2%.
c. Sulfur content of oil is not specified.

Table references:
Source: *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, 2006.
Primary Reference: Khan, S. *Methodology, Assumptions, and References—Preliminary SO_2 Controls Cost Estimates for Industrial Boilers* (EPA-HQ-OAR-2003-0053-166), October-November 2003.
(Converted from 2004 to 2006 dollars using a conversion factor of 1.0672 www.inflationdata.com)

Time Necessary for Compliance

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 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. For the purposes of this review, we have 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.

Refiners in the United States are already producing low sulfur diesel fuel which may be marketed as distillate oil. There is a potential that offshore refiners may not be able to produce enough 15 ppm sulfur for export to the Northeast United States to meet peak demand, but so far this has not occurred.

ICI boilers would not have to retrofit or install expensive control technology to burn ULSD distillate fuel oil, therefore, compliance with the standard is driven by supply and demand of the lower sulfur distillate oils.

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.

Energy and Non-Air Impacts

Fuel switching and cleaning do not significantly affect the efficiency of the boiler but may add to transportation issues and secondary environmental impacts from waste disposal and material handling operations (e.g. fugitive dust). FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

The primary environmental impact of FGD systems is the generation of wastewater and sludge from the SO_2 removal process. When the exhaust gas from the boiler enters the FGD the SO_2, metals, and other solids are removed from the exhaust and collected in the FGD liquid. The liquid slurry collects in the bottom of the FGD in a reaction tank. The slurry is then dewatered and a portion of the contaminant-laden water is removed from the system as wastewater. Waste from the FGD systems will increase sulfate, metals, and solids loading in a facility's wastewater, potentially impacting community wastewater treatment facilities for smaller units that do not have self contained water treatment systems. In some cases FGD operation necessitates installation of a clarifier on site to remove excessive pollutants from wastewater. This places additional burdens on a facility or community wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge must be stabilized prior to land filling. If a calcium sulfate sludge is produced, dewatering alone is necessary before land filling, however, SO_2 removal costs are higher due to increased equipment costs for this type of control system. In some cases calcium sulfate sludge can be sold for use in cement manufacturing.

With wet FGD technologies a significant visible plume is present from the source due to condensation of water vapor as it exits the smoke stack. Although the water eventually evaporates and the plume disappears, community impact may be significant.

Reducing the sulfur contents 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. According to a study conducted by the New York State Energy Research and Development Authority, (NYSERDA), boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. These reductions in buildup of deposits result in longer service intervals between cleanings. (Batey and McDonald 2005)

Remaining Useful Life of the Source

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.

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CHAPTER 5

ANALYSIS OF SELECTED INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

SOURCE CATEGORY DESCRIPTION

Modeling of visibility impacts on Class I regions was conducted by the Vermont Department of Environmental Conservation (VTDEC) and MANE-VU to identify the major ICI sources contributing to visibility impairment in the northeast. Table 5.1 lists the ICI sources identified to contribute significant levels of SO_2 to the MANE-VU region. MACTEC was directed by MARAMA and the Reasonable Progress Workgroup to focus on the 17 major sources listed in Table 5.1.

As explained in the previous chapter, there are a wide variety of proven control technologies for reducing SO_2 emissions from ICI boilers and specifically the control method for SO_2 applied to any individual ICI boiler is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost effective emissions reduction technologies for SO_2 are available and are effective in reducing emissions from the exhaust gas stream of ICI boilers.

INFORMATION OBTAINED FROM STATE AGENCIES

For the selected ICI boilers, MACTEC contacted State and or regional regulatory agencies to evaluate the status of each unit and determine if additional pollution controls had been mandated as a part of regulatory actions taken since the data used for the visibility impairment modeling were collected. Table 5.1 presents the information obtained from the States.

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Motiva Enterprises LLC – Delaware City[1]	DE	29,747	Fluid Coking Unit (FCU) and FCU Carbon Monoxide Boiler	002	57,199 barrels per day of total feed	None	Cansolv Regenerative Wet Gas Scrubber and SNCR	Data from Permit APC-82/0829 Amendment 5 SO_2 permit limit is 174 tpy
			Fluid Catalytic Cracking Unit (FCCU) and FCCU Carbon Monoxide Boiler	012	FCCU coke burn rate limit is 56,000 lbs/hr	None	Cansolv Regenerative Wet Gas Scrubber	Data from Permit APC-82/0981 Amendment 6 SO_2 permit limit is 361 tpy

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Kodak Park Division[2, 3]	NY	23,508	Building 31 and 321 stationary combustion installations, including package ABD built up boilers used for the generation of process steam and electricity Boilers: 1 – Package boiler, No. 6 2 – Package boiler, No. 6 3 – Package boiler, No. 6 4 – Package boiler, No. 6 13 – Underfed stoker, coal 14 – Underfed stoker, coal 11 – Underfed stoker, coal 12 – Underfed stoker, coal 15 – Wet bottom cyclone, coal/No. 6 16 – Wall-fired, coal/No. 6 41 – Wet bottom cyclone, coal/No. 6 42 – Wet bottom cyclone, coal/No. 6 43 – Wet bottom cyclone, coal/No. 6 44 – Tangential-fired pulverized coal, coal/No. 2	U0015 Boilers (EP-031B-1):		None	BART analysis - NO_X & SO_2 controls affordable on Boilers 41, 42, & 43 Wet scrubber (90% reduction) would be ~$2,150/ton Dry scrubber (40% reduction) would be ~$1,850/ton	Process K07 (Bldg 31) is No. 6 fuel oil combustion in package boilers Process K09 (Bldg 31) is bituminous coal combustion in built up Boilers 13 and 14 Process K10 (Bldg 31) is No. 6 fuel oil combustion in built up Boilers 15 and 16 Process K11 (Bldg 31) is bituminous coal combustion for built up Boiler 15 Process K12 (Bldg 321) is No. 6 fuel oil combustion for built up Boilers 41, 42 and 43 Process K13 (Bldg 321) is bituminous coal combustion for built up Boilers 41, 42 and 43 Process K14 (Bldg 321) is No. 2 fuel oil combustion with NSPS applicability in Boiler 44 Process K15 (Bldg 321) is bituminous low sulfur coal combustion
				1	98 MMBTU/hr			
				2	98 MMBTU/hr			
				3	98 MMBTU/hr			
				4	98 MMBTU/hr			
				13	265 MMBTU/hr			
				14	265 MMBTU/hr			
				Boilers (EP-031B-2):				
				11	197 MMBTU/hr			
				12	222 MMBTU/hr			
				15	478 MMBTU/hr			
				16	544 MMBTU/hr			
				Boilers (EP-321B-3):				
				41	500 MMBTU/hr			
				42	500 MMBTU/hr			
				Boilers (EP-321B-4):				
				43	640 MMBTU/hr			
				44	670 MMBTU/hr			

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
MW Custom Papers LLC – Chillicothe Mill[4]	OH	23,216	No.5 Coal Boiler - wet bottom, pulverized coal-fired boiler (C. E. model VU-40), capable of running on #2 fuel oil as backup fuel	B001	380 MMBTU/hr maximum heat input	Cyclone/ multi-clone ESP	None	9.9 lbs of sulfur dioxide per MMBTU actual heat input
			No.7 Coal Boiler - wet bottom, pulverized coal-fired boiler (C. E. model VU-405), capable of running on #2 fuel oil as backup fuel	B002	422 MMBTU/hr maximum heat input	Cyclone/ multi-clone ESP	None	9.9 lbs of sulfur dioxide per MMBTU actual heat input
			No.8 Coal Boiler - wet bottom, pulverized coal-fired boiler (C. E. model VU-40), capable of running on #2 fuel oil as backup fuel.	B003	505 MMBTU/hr maximum heat input	Cyclone/ multi-clone ESP	None	9.9 lbs of sulfur dioxide per MMBTU actual heat input

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Eastman Chemical Company[5, 6]	TN	22,882	Two fuel burning installations (B-83-1 & B-253-1) w/a total of 19 coal fired boilers of which 14 units (#18-#24) are located at Powerhouse B-83-1 & 5 units (#25-#29) are located at Powerhouse B-253-1. The primary fuel is coal. In addition, wood, waste solids, waste liquids, & biosludge may be burned in these Powerhouses, while NG & process gas may also be burned in the Powerhouse B-253-1 boilers.	82-0003-01-19 (020101, 021520)	6,625 Million BTU/hr nominal heat input	ESP	Scubbers potentially	The five boilers in Powerhouse B-253-1 are subject to BART. The State does not have confirmation yet, but they believe that the boilers will be controlled by scrubbers of some sort. Units #11-#17, that were located at Powerhouse B-83-1, have been removed
			Coal-Fired Boilers 30 and 31	PES B-325-1or 82-1010-15 (261501)	Heat input is limited to 780 and 880 MMBTU/hr, respectively, on a 30 calendar day rolling average basis	None	None	
Westvaco Fine Papers[7, 8]	MD	19,083	Boiler 24 is a coal fired-cyclone boiler	1	590 MMBTU/hr maximum heat input	SNCR (NO_X) ESP (PM)	Baghouse (PM)	Not BART eligible due to age

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	**State**	**2002 SO_2 Total (tons)**	**Primary Emissions Point Description**	**Point ID (Permit ID No.)**	**Design Capacity**	**Existing Control(s)**	**Proposed/ Planned Control(s)**	**Additional Information**
			Boiler 25 is a coal fired-tangential boiler	2	785 MMBTU/hr maximum heat input	Low NO_X burners/ overfired air (NO_X) ESP (PM)	Scrubber (FGD in design) SNCR (NO_X) Baghouse to replace ESP (PM)	BART eligible
PPG Industries Inc.[9]	WV	12,678	Boiler 3 is a coal-fired boiler installed in 1942 and modified in 1981	R011 (002) or S076	243 MMBTU/hr	Fabric filter Low NO_X burners	None	Not BART eligible
			Boiler 4 is a coal-fired and natural gas-fired boiler installed in 1952	R015 (001) or S076	496 MMBTU/hr	ESP Low NO_X burners	None	Not BART eligible
			Boiler 5 is a coal-fired boiler installed in 1966	R072 (003) or S482	878 MMBTU/hr	ESP Low NO_X burners	None	BART eligible, facility to decrease emissions by using low-sulfur coal and taking an emission limit of 1,478.8 lb SO_2/hr

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Williams Ethanol Services Inc.[10, 11]	IL	12,244	4 boilers Boiler A & B are coal-fired boilers constructed in 1944 Boiler C is a coal/oil supplemental-fired boiler constructed in 1958 Boiler D is a NG/No. 2 oil-fired boiler constructed in 1976	10	Boilers A & B: 242 MMBTU/hr Boiler C: 330 MMBTU/hr Boiler D: 195 MMBTU/hr	Boilers A & B: Multi-cyclone Boiler C: ESP Boiler D: None	None	Not BART eligible. There is also a steep acid preparation system (Unit 2) that converts sulfur into sulfurous acid that will be used for the steeping process. Total sulfur usage for this unit is limited to 961,750 lbs/yr (at least 48% of the sulfur added to steepwater shall be retained in the products shipped from the plant).

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Corn Products International Inc.[10, 11]	IL	9,281	Utilities: Coal fired Boilers #1, #2, & #3 (pre 1972) Natural gas-fired Boilers #4 & #5 (pre 1972) Natural gas-fired Boiler #6 constructed in 1992 2 natural gas-fired turbines constructed in 1995	Group 9	Boilers #1, #2, & #3: 250 MMBTU/hr Boilers #4 & #5: 312.5 MMBTU/hr Boiler #6: 600 MMBTU/hr Turbines: 65 MMBTU/hr	Boilers #1, #2, & #3: ESP Boilers #4 & #5: None Boiler #6: low-NO_X burner & flue gas recirculation Turbines: None	None	Not BART eligible
Mead Westvaco Packaging Resource Group[12]	VA	8,552	Four (4) boilers #6 – primarily coal-fired #7 – coal/bark/wood-fired #8 - coal/bark/wood-fired #9 – primarily coal-fired	25	550 MMBTU/hr 440 MMBTU/hr 580 MMBTU/hr 807 MMBTU/hr	ESP Scrubbers FGR LNB	None	
PH Glatfelter Co./Spring Grove[13, 14]	PA	7,855	#4 Power Boiler that burns bituminous coal (13 tons/hr), #6 oil (751 gal/hr), & #2 oil (108 gal/hr)	034	363.7 MMBTU/hr	Cyclone dust collector ESP	None	Not BART eligible

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	**State**	**2002 SO_2 Total (tons)**	**Primary Emissions Point Description**	**Point ID (Permit ID No.)**	**Design Capacity**	**Existing Control(s)**	**Proposed/ Planned Control(s)**	**Additional Information**
			#5 Power Boiler that burns bituminous coal (10.3 tons/hr), #6 oil (300 gal/hr), “as fired” wood (12.2 tons/hr), & #2 oil (451.2 gal/hr)	035	262.3 MMBTU/hr	Cyclone dust collector ESP	None	BART eligible
Goodyear Tire & Rubber Co.[4]	OH	5,903	"A" Boiler, which is a coal-fired boiler	B101	301 MMBTU/hr	ESP	None	4.64 lbs of sulfur dioxide per MMBTU actual heat input for B101, B102, and B103 exiting through Stack 4
			"B" Boiler, which is a coal-fired boiler	B102	301 MMBTU/hr	ESP	None	4.64 lbs of sulfur dioxide per MMBTU actual heat input for B101, B102, and B103 exiting through Stack 4
			"C" Boiler, which is a coal-fired boiler	B103	174 MMBTU/hr	ESP	None	4.64 lbs of sulfur dioxide per MMBTU actual heat input for B101, B102, and B103 exiting through Stack 4

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Sunoco Inc. (R&M)[15, 16]	PA	3,645	Plt. 10-4 FCC Unit	101	4,792.000 bbl/hr fresh feed	None	SCR and a wet gas scrubber installed in 2010. At the latest, compliance is required by 2013.	SO_2 limit of 9.8 lbs/1000 lbs of coke burn-off in the catalyst regenerator determined daily on a 7-day rolling average basis
Valero Refining Co. – NJ[17, 18]	NJ	3,597	FCCU Regenerator with In-Line Heater	E21 or U1	102 MMBTU/hr	WGS	None	Per Consent Decree, SO_2 concentration emission limits at the point of emission to the atmosphere of no greater than 25 ppmvd, measured as a 365-day rolling average, and 50 ppmvd, measured as a 7-day rolling average, both at 0% O_2.
Stone Container Corp. (dba Smurfit-Stone Contain)[19]	VA	3,379	#8 Power Boiler that burns bituminous coal	2	1,056 MMBTU/hr	None	Wet gas scrubber (2007)	Consent Decree dated 11/2004 which states that SO_2 emission rate will not exceed 0.26 lb/MMBTU on a 30-day rolling average basis.

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Great Northern Paper Inc. Mill West[20, 21]	ME	1,842	Power Boilers #4 (Riley-Stoker))	004 (WB4)	740 MMBTU/hr	None	None	Unit to be shut down so BART not an issue (only BART eligible source at this facility)
NRG Energy Center Dover LLC[1, 22, 23]	DE	1,836	Riley Stoker Boiler fired on pulverized bituminous coal (primary fuel) and natural gas (for startup/ignition).	C-1 (001)	243 MMBTU/hr	Four (4) DB Riley Low NO_X burners Cyclonic Combustion Venturi burner assemblies Low excess air ESP w/23,000 ft^2 collecting electrode area	None	Not BART eligible
Sappi-Somerset[20, 21]	ME	1,734	Power Boiler #1 (Babcock & Wilcox)	001 (PB#1)	848 MMBTU/hr (all fuels) & 250 MMBTU/hr (fossil fuels)	None	None	CEMS for SO_2 Facility to reduce SO_2 emissions by 50% by 2013 (BART deadline)

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[1] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding Motiva Enterprises LLC – Delaware City and NRG Energy Center Dover LLC facilities received from Mr. John Sipple (302-739-9435, John.Sipple@state.de.us) via E-mail on March 13, 2007.

[2] New York State Department of Environmental Conservation, Division of Air Resources. Personal communications regarding Kodak Park Division facility between Mr. Mike Cronin, P.E. (518-402-8403, mpcronin@gw.dec.state.ny.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on February 1 and 9, 2007.

[3] New York State Department of Environmental Conservation, Division of Air Resources. Personal communications regarding Kodak Park Division facility from Mr. Mike Cronin, P.E. (518-402-8403, mpcronin@gw.dec.state.ny.us) via E-mail on February 12, 2007.

[4] Ohio Environmental Protection Agency, Division of Air Pollution Control. Personal communication regarding MW Custom Papers LLC – Chillicothe Mill and Goodyear Tire and Rubber Company facilities from Mr. William Spires (614-644-3618, bill.spires@epa.state.oh.us) via E-mails on February 20, 2007.

[5] Tennessee Department of Environment and Conservation, Division of Air Pollution Control. Personal communication regarding Eastman Chemical Company facility from Ms. Julie Aslinger (615-532-0587, Julie.Aslinger@state.tn.us) via E-mail on March 1, 2007.

[6] MACTEC Federal Programs, Inc., “Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas”, March 8, 2007. Comments regarding Eastman Chemical Company facility received from Ms. Julie Aslinger (615-532-0587, Julie.Aslinger@state.tn.us) via E-mail on March 30, 2007.

[7] Maryland Department of the Environment. Personal communication regarding Westvaco Fine Papers facility between Mr. Andy Heltibridle (410-537-4218, aheltibridle@mde.state.md.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[8] Maryland Department of the Environment. Personal communication regarding Westvaco Fine Papers facility from Mr. Andy Heltibridle (410-537-4218, aheltibridle@mde.state.md.us) via E-mail on January 31, 2007.

[9] West Virginia Division of Air Quality. Personal communications regarding PPG, Industries, Inc. facility between Ms. Laura Crowder (304-926-0499 Ext. 1247, LCROWDER@wvdep.org) and Mr. Steve Pursley (304-926-0499 Ext. 1218) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on March 14, 2007.

[10] Virginia Department of Environmental Quality, Division of Air Quality. Personal communication regarding Mead Westvaco Packaging Resource Group facility between Ms. Doris McLeod (504-698-4197, damcleod@deq.virginia.gov) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on February 20, 2007.

[11] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communication regarding PH Glatfelter Company/Spring Grove facility between Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[12] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding PH Glatfelter Company/Spring Grove facility from Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) via E-mail on January 31 and February 7, 2007.

[13] Illinois Environmental Protection Agency, Bureau of Air. Personal communication regarding Williams Ethanol Services Incorporated and Corn Products International Incorporated facilities between Mr. Rob Kaleel (217-524-4387, Rob.Kaleel@illinois.gov) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on February 2, 2007.

[14] Illinois Environmental Protection Agency, Bureau of Air. Personal communication regarding Williams Ethanol Services Incorporated and Corn Products International Incorporated facilities from Mr. Rob Kaleel (217-524-4387, Rob.Kaleel@illinois.gov) via E-mail on February 2, 2007.

[15] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding Sunoco Inc. (R&M) facility between Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[16] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding Sunoco Inc. (R&M) facility from Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) via E-mail on February 22, 2007.

[17] New Jersey Department of Environmental Protection, Division of Air Quality. Personal communications regarding Valero Refining Company facility between Mr. Ray Papalski (609-633-7225, Ray.Papalski@dep.state.nj.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31 and February 2, 2007.

[18] New Jersey Department of Environmental Protection, Division of Air Quality. Personal communication regarding Valero Refining Company facility from Mr. Ray Papalski (609-633-7225, Ray.Papalski@dep.state.nj.us) via E-mail on February 21, 2007.

[19] Virginia Department of Environmental Quality, Division of Air Quality. Personal communication regarding Stone Container Corporation facility from Ms. Doris McLeod (504-698-4197, damcleod@deq.virginia.gov) via E-mail on February 9, 2007.

[20] Maine Department of Environmental Protection Agency, Bureau of Air Quality. Personal communications regarding Great Northern Paper Incorporated Mill West and Sappi - Somerset facilities between Ms. Lynn Ross (207-287-8106, Lynn.Ross@maine.gov) and Mr. Marc Cone (207-287-2437) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on February 2, 2007.

[21] Maine Department of Environmental Protection Agency, Bureau of Air Quality. Personal communication regarding Great Northern Paper Incorporated Mill West and Sappi - Somerset facilities between Ms. Lynn Ross (207-287-8106, Lynn.Ross@maine.gov) via E-mail on February 2, 2007.

[22] Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management. Personal communications regarding NRG Energy Center Dover LLC facility between Ms. Tammy Henry (302-323-4542, Tammy.Henry@state.de.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on March 5, 2007.

[23] Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management. Personal communications regarding NRG Energy Center Dover LLC facility from Ms. Tammy Henry (302-323-4542, Tammy.Henry@state.de.us) via E-mail on March 5, 2007.

CHAPTER 6

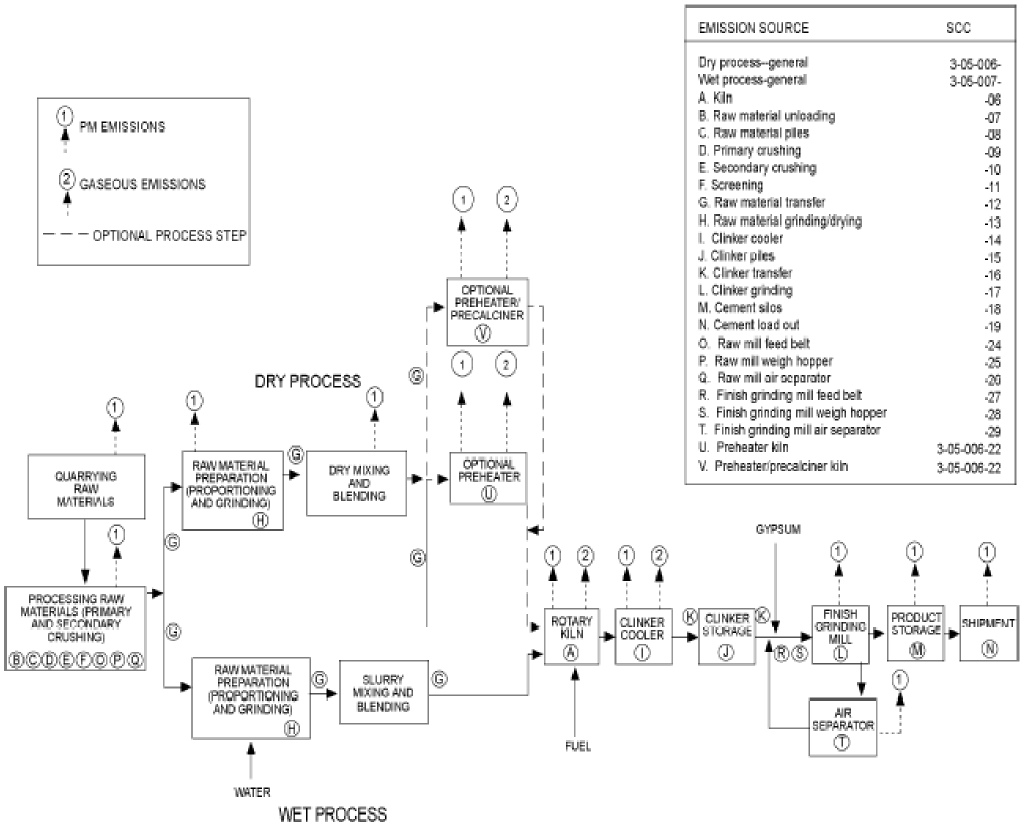
SOURCE CATEGORY ANALYSIS: KILNS

SOURCE CATEGORY DESCRIPTION

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 1,400°C (2,650°F). High combustion temperatures require large amounts of fuel and can result in significant emissions of SO_2 and NO_X. Crushing of ingredients and finished clinker can release dust and particles. Ammonia is sometimes produced during the heating of limestone.

Figure 6.1 shows a process flow diagram of a Portland cement facility. The process flow diagram (taken from AP-42) shows both wet and dry Portland cement processes.

Figure 6.1 Portland Cement Process Flow Diagram



EMISSION SOURCE	SCC
Dry process--general	3-05-006-
Wet process-general	3-05-007-
A. Kiln	-06
B. Raw material unloading	-07
C. Raw material piles	-08
D. Primary crushing	-09
E. Secondary crushing	-10
F. Screening	-11
G. Raw material transfer	-12
H. Raw material grinding/drying	-13
I. Clinker cooler	-14
J. Clinker piles	-15
K. Clinker transfer	-16
L. Clinker grinding	-17
M. Cement silos	-18
N. Cement load out	-19
O. Raw mill feed belt	-24
P. Raw mill weigh hopper	-25
Q. Raw mill air separator	-26
R. Finish grinding mill feed belt	-27
S. Finish grinding mill weigh hopper	-28
T. Finish grinding mill air separator	-29
U. Preheater kiln	3-05-006-22
V. Preheater/precalciner kiln	3-05-006-22

EPA. January, 1995. AP42 Section 11.6 – “Portland Cement Manufacturing”.

Figure 6.1 shows that the Portland cement process can generally be broken down into the following steps: raw materials handling, raw material preparation, dry mixing, optional preheating and/or precalcining, kiln treatment (pyroprocessing step), clinker handling and storage, and finishing operations (finishing, storage and shipment). The pyroprocessing step transforms the raw mix into clinkers, which are gray, glass-hard, spherically shaped nodules that range from 0.125 to 2.0 inches in diameter.

The pyroprocessing step is the predominant source of gaseous pollutant emissions. In general, there are five different processes used in the Portland cement industry to accomplish the pyroprocessing step: the wet process, the dry process (long dry process), the semidry process, the dry process with a preheater, and the dry process with a preheater/precalciner.

Each of the pyroprocessing types vary with respect to equipment design, method of operation, and fuel consumption. Generally, fuel consumption decreases in the order of the processes listed due to the heat required to evaporate water present in the raw material slurry (e.g., wet processes use the most fuel).

In the long dry process, all of the pyroprocessing activity occurs in the rotary kiln. Dry process pyroprocessing systems have been improved in thermal efficiency and productive capacity through the addition of one or more cyclone-type preheater vessels in the gas stream exiting the rotary kiln. This system is called the preheater process. The vessels are arranged vertically, in series, and are supported by a structure known as the preheater tower. Hot exhaust gases from the rotary kiln pass countercurrently through the downward-moving raw materials in the preheater vessels. Compared to the simple rotary kiln (long dry process), the heat transfer rate is significantly increased, the degree of heat utilization is greater, and the process time is markedly reduced by the intimate contact of the solid particles with the hot gases. The improved heat transfer allows the length of the rotary kiln to be reduced. An added benefit of the preheater operation is that hot gases from the preheater tower are used to help dry raw materials in the raw mill. Because the catch from the mechanical collectors, fabric filters, and/or electrostatic precipitators (ESP) that follow the raw mill is returned to the process, these devices can also be considered to be production machines as well as pollution control devices.

Additional thermal efficiencies and productivity gains have been achieved by diverting some of the fuel to a calciner vessel at the base of the preheater tower. This system is called the preheater/precalciner process.

Regardless of the type of pyroprocess used, the last component of the pyroprocessing system is the clinker cooler. The clinker cooler serves two main purposes. First, this portion of the process:

- recoups up to 30% of the heat input to the kiln system;
- locks in desirable product qualities by freezing mineralogy; and
- makes it possible to handle the cooled clinker with conventional conveying equipment.

The more common types of clinker coolers are reciprocating grate, planetary, and rotary. In these coolers, the clinker is cooled from about 1,100°C to 90°C (2000°F to 200°F) by ambient air that passes through the clinker and into the rotary kiln for use as combustion air. However, in the reciprocating grate cooler, lower clinker discharge temperatures are achieved by passing an additional quantity of air through the clinker. Because this additional air cannot be used in the kiln for efficient combustion, it is vented to the atmosphere, used for drying coal or raw materials, or used as a combustion air source for the precalciner.

The second portion of the clinker process, a series of blending and grinding operations, completes the transformation of clinker into finished cement. Up to 5% gypsum or natural anhydrite is added to the clinker during grinding to control the cement setting time, and other specialty chemicals are added as needed to impart specific product properties. This finish milling is accomplished almost exclusively in ball or tube mills. Typically, finishing is conducted in a closed-circuit system, with product sizing by air separation.

Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes to the product. The current fuel usage in cement kilns is about 82% coal; 4% natural gas; and 14% other fuels, mainly combustible waste (industrial waste, tires, sewage sludge, etc.). In addition to conventional fuels, many Portland cement facilities are employing the use of petroleum derived coke (petcoke) blended with coal to fire kilns.

Lime kilns are similar to cement kilns. The kiln is the heart of the lime manufacturing plant, where various fossil fuels (such as coal, petroleum coke, natural gas, and fuel oil) are combusted to produce the heat needed for calcination. There are five different types of kilns used in lime manufacturing: rotary, vertical, double-shaft vertical, rotary hearth, and fluidized bed. The most popular is the rotary kiln, however the double-shaft vertical kiln is an emerging new kiln technology gaining in acceptance primarily due to its energy efficiency. Similar to cement plants, rotary kilns at lime manufacturing plants may also have preheaters to improve energy efficiency. Additionally, energy efficiency is improved by routing exhaust from the lime cooler to the kiln. SO_2 emissions from lime predominately originate from compounds in the limestone feed material and fuels and are formed from the combustion of fuels and the heating of feed material in the kiln.

All types of kilns at lime manufacturing plants use external equipment to cool the lime product, except vertical (including double-shaft) kilns, where the cooling zone is part of the kiln. Ambient air is most often used to cool the lime (although a few use water as the heat transfer medium), and typically all of the heated air stream exiting the cooler goes to the kiln to be used as combustion air for the kiln. The exception to this is the grate cooler, where more airflow is generated than is needed for kiln combustion, and consequently a portion (about 40%) of the grate cooler exhaust is vented to the atmosphere. EPA has estimated that there are about five to ten kilns in the United States that use grate coolers. The emissions from grate coolers include lime dust (PM) and trace metallic HAPs found in the lime dust, but not typically SO_2.

For cement and lime kilns, add-on control technology options identified for SO_2 include advanced flue gas desulfurization (AFGD), dry FGD, and wet FGD.

EVALUATION OF SO_2 EMISSION CONTROL OPTIONS

Sulfur dioxide may be generated both from the sulfur compounds in the raw materials and from sulfur in the fuel. The sulfur content of both raw materials and fuels varies from plant to plant and with geographic location. However, the alkaline nature of the cement provides for direct absorption of SO_2 into the product, thereby reducing the quantity of SO_2 emissions in the exhaust stream. Depending on the process and the source of the sulfur, SO_2 absorption ranges from about 70% to more than 95%.

In contrast to electric utility and industrial boilers, SO_2 emissions from rotary cement kilns are not strongly dependent on fuel sulfur content. Instead, SO_2 emissions are more closely related to the amount of sulfide (e.g. pyrite) in kiln feedstocks 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 during processing,
- 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 the kiln, and
- Temperature profile in the kiln system.

SO_2 emission reductions may also result from attempts to reduce other pollutants (primarily NO_X), typically due to changes in the flame characteristics of combustion. For example, staged combustion with mid-kiln injection of a low-sulfur fuel may be considered for reducing SO_2. Similarly, 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 and because their efficiencies are typically more limited than other techniques they are not considered in additional detail here.

Other more specific SO_2 control technologies applicable to cement kilns are listed below. A summary of controls evaluated for this work is provided in Table 6.1. Details of each of the control technologies follow Table 6.1. Additional information on this source category and associated controls can be found in the 2005 NESCAUM document titled: *Assessment of Control Technology Options for BART-Eligible Sources.*

Table 6.1 SO_2 Control Technologies for Cement Kilns

Technology	**Description**	**Applicability**	**Performance**
Fuel Switching	Limiting the sulfur content of both raw materials and fuels can reduce releases of SO_2. Availability of these materials is highly site-specific.	All Kilns	Depends on availability of low-sulfur raw materials
Dry Flue Gas Desulfurization - Spray Dryer Absorption (FGD)	Addition of absorbents such as slaked lime (Ca(OH)2), quicklime (CaO) or activated fly ash with high CaO content to the exhaust gas of the kiln can absorb some of the SO_2.	All Kilns	60-80% reduction
Wet Flue Gas Desulfurization (FGD)	SO_2 is absorbed by a liquid/slurry sprayed in a spray tower or is bubbled through the liquid/slurry. Wet scrubbers also significantly reduce the HCl, residual dust, metal and NH_3 emissions.	All Kilns	90-99.9% reduction
Advanced Flue Gas Desulfurization (FGD)	DOE demonstrated a retrofit Passamaquoddy Technology Recovery Scrubber™ using cement kiln dust (CKD), an alkaline-rich (potassium) waste, to react with the acidic flue gas.	All Kilns	95-99.5% reduction

Table References:
1. *Assessment of Control Technology Options for BART-Eligible Sources*, NESCAUM, March 2005.
2. Miller, F.M. et. al. *Formation and Techniques of Control of Sulfur Dioxide and Other Sulfur Compounds in Portland Cement Kiln Systems*. Portland Cement Association R&D Serial No. 2460, 2001.

Fuel Switching

As with any fuel-fired SO_2 emission source, reduction of sulfur levels in the fuel itself typically results in lowered emissions. However, this technique 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, and more specifically the pyrite content, 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.

Flue Gas Desulfurization (FGD)

Both wet and dry flue gas desulfurization (FGD) systems have been used effectively to control SO_2 emissions from cement kilns. FGD systems at cement facilities typically are, 1) dry flue gas desulfurization (spray dryer absorption) 2) wet flue gas desulfurization, and 3) advanced flue gas desulfurization (AFGD). A brief description of each of these technologies is provided below.

Dry Flue Gas Desulfurization (Spray Dryer Absorption)

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming a mixture of calcium sulfite and calcium sulfate. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or ESP. When used to specifically control SO_2, the term dry flue-gas desulfurization (dry FGD) may also be used. As with other types of dry scrubbing systems (such as lime/limestone injection) exhaust gases that exit at or near the adiabatic saturation temperatures can create problems with this control technology by causing the baghouse filter cake to become saturated with moisture and plug both the filters and the dust removal system. In addition, the lime slurry would not dry properly and would plug up the dust collection system. However there is some argument in the control community that indicates that some of the SO_2 removal actually occurs on the filter cake. Therefore, dry FGD (spray dryer absorption) may not be technically feasible if exit gas temperatures are not substantially above the adiabatic saturation temperatures. For Portland cement facilities, these temperatures are likely to be above the adiabatic saturation temperatures.

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 wet suppression or dilution air enables the alkaline slurry system to be used to reduce SO_2 emissions (the equivalent of a spray dryer). The use of an alkaline slurry spray dryer type scrubber should be applied to long wet kilns with care because the addition of the lime slurry may drop the exhaust gases temperature below the acid adiabatic saturation temperatures, creating significant plugging and corrosion problems in the downstream particulate control device, duct work, and induced draft fan.

Wet Flue Gas Desulfurization (FGD)

Wet scrubbing processes used to control SO_2 and particulate emissions are generally termed flue-gas desulfurization (FGD). FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO_2 in the waste gas. Caustic, crushed limestone, or lime are used as scrubbing agents. Our screening evaluation assumes that lime is the scrubbing agent.

Caustic scrubbing produces a liquid waste, and minimal equipment is needed. When lime or limestone is used as the reagent for SO_2 removal, additional equipment is needed for preparing the lime/limestone slurry and collecting and concentrating the resultant sludge. Calcium sulfite sludge is watery and is typically stabilized with fly ash for land filling. Calcium sulfate sludge is stable and easy to dewater. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur. The normal SO_2 control efficiency range for SO_2 scrubbers is 80-90% for low efficiency scrubbers and 90-99.9% for high efficiency scrubbers.

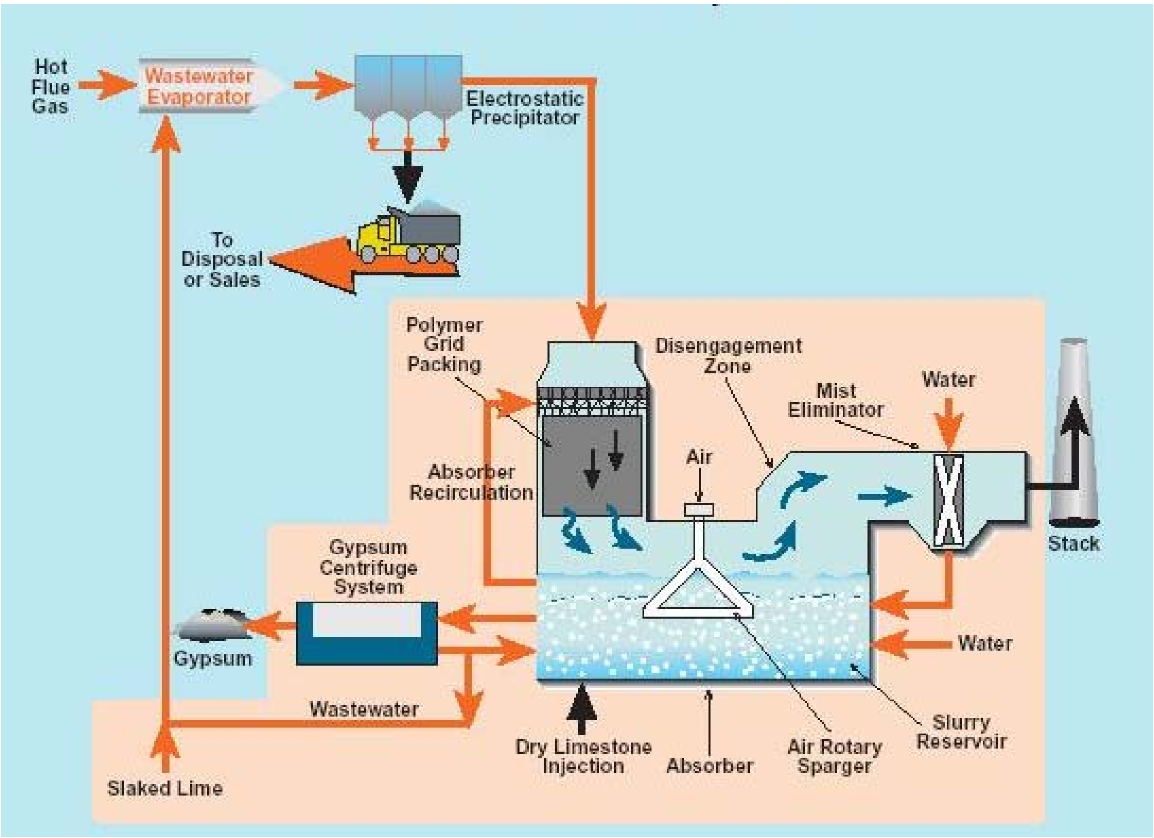
While wet scrubbers have been used successfully in the utility industry, they require more care when used for a Portland cement facility. Calcium sulfate scaling and cementitious buildup when a wet scrubber is used for acid gas control (applied to the exhaust gas from a cement kiln) can be avoided if these systems are installed downstream of a high efficiency particulate control device (e.g., fabric filter). Failure of the particulate control device can pose difficult problems for a downstream wet scrubber.

<u>Advanced Flue Gas Desulfurization (FGD)</u>

The AFGD process accomplishes SO_2 removal in a single absorber which performs three functions: prequenching the flue gas, absorbing SO_2, and oxidizing the resulting calcium sulfite to wallboard-grade gypsum. Figure 6.2 shows the process flow for an AFGD system.

Incoming flue gas is cooled and humidified with process wet suppression before passing to the absorber. In the absorber, two tiers of fountain-like sprays distribute reagent slurry over polymer grid packing that provides a large surface area for gas/liquid contact. The gas then enters a large gas/liquid disengagement zone above the slurry reservoir in the bottom of the absorber and exits through a horizontal mist eliminator.

Figure 6.2 Advanced Flue Gas Desulfurization Process Flow



As the flue gas contacts the slurry, the sulfur dioxide is absorbed, neutralized, and partially oxidized to calcium sulfite and calcium sulfate. The overall reactions are shown in the following equations:

$CaCO_3 + SO_2 \rightarrow CaSO_3 \cdot 1/2\ H_2O + CO_2$

$CaSO_3 \cdot 1/2\ H_2O + 3H_2O + O_2 \rightarrow 2\ CaSO_4 \cdot 2\ H_2O$

After contacting the flue gas, slurry falls into the slurry reservoir where any unreacted acids are neutralized by limestone injected in dry powder form into the reservoir. The primary reaction product, calcium sulfite, is oxidized to gypsum by the air rotary spargers, which both mix the slurry in the reservoir and inject air into it. Fixed air spargers assist in completing the oxidation. Slurry from the reservoir is circulated to the absorber grid.

A slurry stream is drawn from the tank, dewatered, and washed to remove chlorides and produce wallboard quality gypsum. The resultant gypsum cake contains less than 10% water and 20 ppm chlorides. The clarified liquid is returned to the reservoir, with a slipstream being withdrawn and sent to the wastewater evaporation system for injection into the hot flue gas ahead of the electrostatic precipitator. Water evaporates and dissolved solids are collected along with the flyash for disposal or sale.

The production of gypsum may actually be beneficial for Portland cement as gypsum is added to Portland cement in the final grinding process to regulate the setting time of the concrete. However, to date there are no known installations of AFGD at Portland cement facilities.

Inherent Removal

Removal of SO_2 in the cement manufacturing process is inherent to that process. The raw materials used in the process, 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 generating a free lime, which then reacts with SO_2 in the gas stream, 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). The overall effectiveness and costs associated with this method are highly variable and are related primarily to the type of kiln operation and the ability of the facility to change raw material feeds. These costs can be difficult to quantify.

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:

- Change in the oxygen concentration in the flame/exhaust gas area. The concentrations of oxygen and (more importantly) carbon monoxide strongly influence the stability of alkali and calcium sulfates in the burning zone. By ensuring that sufficient oxygen is present to stabilize these compounds, SO_2 emissions can be controlled. Control of burning-zone O_2 and CO concentrations is a widely used industrial practice, and a control technique applicable to all rotary cement kilns. 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 ensure that reducing conditions in the flame are minimized. Flame impingement in the hot zone has 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.
- Changes in raw materials to alter the alkali/sulfur molar ratio can also be used to control SO_2 emissions. SO_2 concentrations in kiln exit gases vary with the molar ratio of alkali to sulfur. When there are sufficient alkalis in excess of sulfur, SO_2 emissions are typically low, due to more sulfur being retained as alkali sulfates in the clinker. Cement plants may also change their raw materials to reduce SO_2 emissions. Typically this is accomplished by substituting a raw material containing pyritic sulfur or organic sulfur with one containing lesser amounts of these compounds, leading to reduced 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).

As with inherent removal, the overall effectiveness and costs associated with this method are highly variable and are related primarily to the type of kiln operation and the ability of the facility to change raw material feeds. These costs can be difficult to quantify.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR KILNS

Cost of Compliance

To compare the various control options, information has been compiled on the cost-effectiveness of retrofitting controls. In general, cost-effectiveness increases with the amount of cement produced by the facility.

In a study performed for LADCO for a BART analysis, MACTEC developed control costs for SO_2 for a "model" cement plant for SO_2. For the wet scrubber, the control cost estimates were prepared using lime as the base in the scrubbing liquor. Caustic (NaOH) and limestone are potential alternatives for a scrubber and could change the costs slightly. While lime and limestone require additional equipment for slurry preparation and for solids separation from the sludge generated in the scrubber, lime scrubbers are the most commonly used since lime is plentiful and relatively cheap. Materials of construction must also be made suitable for caustic, lime, or limestone if existing equipment is modified for wet scrubbing of SO_2.

AFGD systems require additional capital costs for the spargers and blowers necessary to oxidize the waste product to gypsum and for equipment to dewater the product (e.g., centrifuge). However if the commercial grade gypsum can be sold or used by the cement facility, some of these costs can be offset.

Dry FGD costs were calculated based on the low and high control efficiencies typical for these systems. For dry scrubbers, the flue gas must be cooled to a temperature 10 to 20 degrees above adiabatic saturation. This is typically accomplished using a heat recovery boiler, an evaporative cooler or a heat exchanger. In addition, if the facility does not have one, a particulate removal device is required for removal of the dry materials used to absorb SO_2.

For all scrubbers, costs for an additional or upgraded induced air draft fan to make up for pressure drops within the system may be required. In addition, for wet systems, flue gas reheating may be required, thus a reheater may be necessary.

Tables 6.2 – 6.4 present estimated SO_2 control costs for AFGD, Wet FGD, and Dry FGD applied to dry kilns and preheater kilns. The range of costs for these systems vary depending on the size of the kiln and control efficiency, so costs are presented for three size ranges of kilns. Although the capital and annual operating costs of these three types of control vary widely depending on kiln size and control efficiency, the ultimate cost in terms of $/ton of SO_2 reduction are estimated to be from $2,000 - $7,000 for dry kilns and $9,000 to $73,000 for preheater kilns.

Table 6.2 SO_2 Control Costs for AFGD Applied to Dry Kilns and Preheater Kilns (2006 dollars)

	Dry Kiln			**Preheater Kiln**		
Unit Relative Size	Capital Costs (10^6 $)	Annual Operating Costs (10^6 $)	SO_2 Cost Effectiveness ($/ton SO_2 reduction)	Capital Costs (10^6 $)	Annual Operating Costs (10^6 $)	SO_2 Cost Effectiveness ($/ton SO_2 reduction)
Small	$7.03 – $22.9	$3 - $6	$2,000 - $4,000	$4.5 - $14.5	$1.2 – $11.8	$13,600-$38,000
Medium	$14.1 - $45.9	$6.1 - $11.9		$8.9 - $29.0		
Large	$28.1 - $91.6	$12.1 – $23.7		$17.8 - $58.0		

Table 6.3 SO_2 Control Costs for Wet FGD Applied to Dry Kilns and Preheater Kilns (2006 dollars)

	Dry Kiln			**Preheater Kiln**		
Unit Relative Size	Capital Costs (10^6 $)	Annual Operating Costs (10^6 $)	SO_2 Cost Effectiveness ($/ton SO_2 reduction)	Capital Costs (10^6 $)	Annual Operating Costs (10^6 $)	SO_2 Cost Effectiveness ($/ton SO_2 reduction)
Small	$2.43 – $36.5	$3 - $9	$2,000 - $6,200	$1.5 - $23.1	$0.9 – $18.9	$9,700-$64,600
Medium	$4.9 - $73.0	$6.0 - $18.4		$3.1 - $46.3		
Large	$9.5 - $142.5	$11.9 – $36.8		$6.2 - $92.5		

Table 6.4 SO_2 Control Costs for Dry FGD Applied to Dry Kilns and Preheater Kilns (2006 dollars)

	Dry Kiln			**Preheater Kiln**		
Unit Relative Size	Capital Costs (10^6 \$)	Annual Operating Costs (10^6 \$)	SO_2 Cost Effectiveness (\$/ton SO_2 reduction)	Capital Costs (10^6 \$)	Annual Operating Costs (10^6 \$)	SO_2 Cost Effectiveness (\$/ton SO_2 reduction)
Small	\$1.45 – \$37.0	\$3 - \$9	\$1,900 - \$7,000	\$0.9 - \$26.3	\$0.9 – \$21.0	\$10,000-\$72,800
Medium	\$2.9 - \$84.9	\$5.5 - \$20.0		\$1.8 - \$52.6		
Large	\$5.6 - \$165.5	\$10.7 – \$38.9		\$3.6 - \$105.2		

The LADCO region had no wet kilns so cost estimates were not available for those type kilns. For the purposes of this study, wet kiln cost effectiveness is assumed to be similar to that for long dry kilns.

Additional details concerning the calculation of cost effectiveness of controls for kilns is located in a document developed by MACTEC for LADCO titled: *Cement Best Available Retrofit Technology (BART) Engineering Analysis*. This document can be downloaded from the web at the following location:
http://www.ladco.org/reports/rpo/Regional%20Air%20Quality/BART/Cement_BART_Engineering%20Analysis%20%2B%20Appendix%20A1.pdf.

Time Necessary for Compliance

Generally, sources are given a 2-4 year phase-in period to comply with new rules. Under the NO_X SIP Call for Phase I sources, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase II of the NO_X SIP Call, EPA provided a 2-year period after the SIP submittal date for compliance. States generally provided a 2-year period for compliance with RACT rules. 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.

For the purposes of this review, we have 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.

Energy and Non-Air Impacts

Fuel switching and cleaning and process changes do not significantly impact efficiency of the cement operation, but may add to transportation issues and secondary environmental impacts from waste disposal and material handling operations (e.g. fugitive dust). FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

Environmental Impacts

The primary environmental impact of AFGD is the generation of byproduct gypsum. While gypsum is generated as a byproduct, the intent of the AFGD system is to produce gypsum that is commercial grade that can be sold. In the case of cement kilns, production of gypsum would result in some cost offsets since gypsum is a component of Portland cement. Thus the gypsum produced could be used to offset gypsum purchases.

The primary environmental impact of wet scrubbers is the generation of wastewater and sludge. Waste from wet scrubbers will increase the sulfate and solids loading in the facility's wastewater. This places additional burdens on a facility's wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge is water-laden, and it must be stabilized for land filling. If lime or limestone scrubbing is used to produce calcium sulfate sludge, it is stable and easy to dewater. However, control costs will be higher because additional equipment is required. Scrubber exhaust gases are saturated with water, thus creating a visible plume. Plume visibility may be a local/community concern. Once the exhaust mixes with sufficient air, the moisture droplets evaporate, and the plume is no longer visible.

Disposal of removed material from dry FGD systems is also required and will result in landfill impacts.

Energy Impacts

A scrubber operates with a high pressure drop, resulting in a significant amount of electricity required to operate the blower and pump. In addition for some technologies, a flue gas reheater may be required resulting in slightly increased fuel usage.

Remaining Useful Life of the Source

MACTEC could find little information on the typical lifetime of a cement plant. In a Security and Exchange filing (http://www.secbd.org/prosmcldopr.html) for a facility in India, typical lifetimes of various components of the plant range between 20-50 years. In an evaluation of waste management of cement kiln dust (CKD), remaining useful lifetimes of waste management units were around 20 years (http://www.epa.gov/epaoswer/other/ckd/rtc/chap-4.pdf). Thus we found nothing to suggest that the amortization of capital costs or calculation of annual operating costs would be affected by the remaining useful life.

For the purposes of this analysis, we assumed that the remaining useful life of each emission unit was a minimum of at least 10 years and that it was likely that some units would continue to operate for at least 20-30 more years with proper maintenance and upkeep.

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CHAPTER 7

ANALYSIS OF SELECTED KILNS

SOURCE CATEGORY DESCRIPTION

Emission control regulations for cement kilns have historically focused on particulate emissions. Over the past several years, regulations for the control of NO_X and hazardous air pollutant (HAP) emissions have also been adopted. SO_2 emission controls are largely non-existent. Some States have mandated emission limits as part of the Title V requirements but no national regulatory program for SO_2 controls for cement kilns exists. The only exceptions to this is for sources subject to New Source Review under Title I of the Clean Air Act and for sources subject to the Best Available Retrofit Technology (BART) requirements of the regional haze regulations.

Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency (known as New Source Review, or NSR). NSR prescribes control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in nonattainment areas. The control strategies that constitute BACT and LAER evolve over time and are reviewed on a case-by-case basis in State permitting proceedings.

INFORMATION OBTAINED FROM STATE AGENCIES

MACTEC contacted State agencies to obtain information on kilns from those facilities in the list of the top 20 individual non-EGU sources. We requested permit information, information about SO_2 controls recently implemented or planned at the facility and any available information on BART, consent decrees, or other regulations that will impact control devices at the facilities. The information we obtained is included in Table 7.1.

Table 7.1 Point Source Information Collected from the Top 3 Kilns Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	**State**	**2002 SO_2 Total (tons)**	**Primary Emissions Point Description**	**Point ID (Permit ID No.)**	**Design Capacity**	**Existing Control(s)**	**Proposed/ Planned Control(s)**	**Additional Information**
LaFarge Building Materials Inc.[1]	NY	14,800	Two rotary, wet process kilns (Kiln 1 & 2) and two clinker coolers (Clinker Cooler 1 & 2). There are buildings at either end of the kilns; the discharge end building where the clinker coolers are located, and the feed end building.	041000	Unknown	Fabric filter dust collector on clinker coolers (PM) ESP (PM)	None	
St. Lawrence Cement Corp. – Catskill Quarry[2, 3]	NY	3,562	Cement kiln permitted to burn coal, oil, tires, waste oil, natural gas, non-hazardous fuels, and coke. This is a wet kiln built in 1964.	U00K18	Unknown	ESP	Low-sulfur fuel	Consent Decree dated 1/9/91 limits burning solid fuel with a max sulfur content of 3.8 lbs/MMBTU/hr. BART analysis has not been completed.
Lafarge Midwest, Inc., Alpena Plant[4]	MI	16,576	Five rotary dry kilns, clinker coolers and associated materials handling operations. Kilns fire with coal, coke or waste derived fuel	EU-Kiln19 EU-Kiln20 EU-Kiln21 EU-Kiln22 EU-Kiln23	Unknown	Baghouses on kiln dust return systems	Unknown as of date of report - these units are subject to BART	SO_2 Emission limits on all five kilns: EUKiln19 = 2,088 tons EUKiln20 = 2,065 tons EUKiln21 = 2,056 tons EUKiln22 = 9,685 tons EUKiln23 = 9,728 tons

[1] New York State Department of Environmental Conservation, Division of Air Resources. Personal communication regarding LaFarge Building Materials Incorporated facility between Mr. Rick Leone (518-402-8403) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on February 2, 2007.

[2] New York State Department of Environmental Conservation, Division of Air Resources. Personal communication regarding St. Lawrence Cement Corporation – Catskill Quarry facility between Mr. Rick Leone (518-402-8403) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on February 9, 2007.

[3] New York State Department of Environmental Conservation, Division of Air Resources. Personal communication regarding St. Lawrence Cement Corporation – Catskill Quarry facility from Mr. Rick Leone (518-402-8403) via E-mail on February 9, 2007.

[4] Michigan Department of Environmental Quality, Air Quality Division. Personal communication regarding LaFarge Midwest, Incorporated Alpena Plant from Ms. Teresa Walker (517-335-2247, walkertr@michigan.gov) via E-mail on February 7, 2007.

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CHAPTER 8

HEATING OIL

BACKGROUND

Number 2 distillate fuel oil, heating oil, and diesel fuel oil are essentially the same refinery-produced liquid. In the Northeast United States, home heating accounts for 54% of distillate fuel oil demand. In comparison, highway diesel accounts for 38% (NESCAUM, 2005). Annually, home heating oil use generates an estimated 100,000 tons of sulfur dioxide (SO_2) emissions in the Northeast (NESCAUM, 2005). Climate and seasonality play important roles in the use of heating oil, and therefore the emissions from combustion of heating oil. While it is important to consider the emissions from heating oil in the Northeast United States, emissions from heating oil combustion in other areas of the United States such as the VISTAS States are not significant in comparison to other emission sources.

SO_2 emissions are proportional to fuel oil sulfur content. It is not feasible to control SO_2 emissions from homes using control devices; therefore, the most efficient method for controlling SO_2 emissions from home heating is by lowering the amount of sulfur in the fuel. Currently, the sulfur limits in heating oil vary between 2,000 to 20,000 ppm. Table 8.1 provides information on the range of sulfur in heating oils throughout the Northeast.

Table 8.1 State Sulfur Limits for Heating Oil

State	Sulfur Limit in Percent	Sulfur Limit in parts per million (ppm)
Connecticut	0.3	3,000
Maine	0.3 to 0.5	3,000 to 5,000
Massachusetts	0.3	3,000
New Hampshire	0.4	4,000
New Jersey	0.2 to 0.3	2,000 to 3,000
New York Upstate	1.0 to 1.5	10,000 to 15,000
New York Downstate	0.2 to 0.37	2,000 to 3,700
Rhode Island	0.5	5,000
Vermont	2.0	20,000

Source: NESCAUM, 2005

Beginning in 2006, the permissible level of sulfur in highway diesel fuel (ultra low sulfur diesel, or ULSD) was 15 ppm. Prior to that, highway low sulfur diesel fuel was refined to contain 500 ppm sulfur (Low Sulfur Diesel, or LSD). Consequently, refineries have already performed the capital investments required for the production of LSD and ULSD fuel oil. The Northeast States are considering adopting consistent low sulfur heating oil requirements, and a memorandum titled *DRAFT Memorandum of Understanding for Regional Fuel Sulfur Content Standards for*

Distillate Number 2 Heating Oil, the Northeast States proposed to reduce the sulfur content to 500 ppm. A reduction of sulfur in heating oils from the current levels to 500 ppm would reduce SO_2 emissions by approximately 75% per year on a nationwide basis (Batey and McDonald, 2005). There has also been some discussion regarding the reduction of heating oil sulfur content to 15 ppm.

This memorandum presents the four factor analysis that was applied to the heating oil sulfur reduction proposal. The four factors are: cost of compliance, time necessary for compliance, energy and non-air impacts, and remaining useful life of the sources. This document primarily focuses on reducing the sulfur content of heating oil to 500 ppm. Information on reducing the sulfur content of heating oil to 15 ppm is presented wherever data were available.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR EMISSIONS FROM HEATING OIL COMBUSTION

Cost of Compliance

Refinery Retrofit Costs

Refineries were required to make significant capital investments to meet the LSD and ULSD highway fuel sulfur requirement. To achieve the LSD and ULSD sulfur goals, refineries were required to implement diesel desulfurization technologies. Estimates for the capital costs were developed in 2001 by the Energy Information Administration (EIA) and are based on calendar year 1999. Table 8.2 presents the capital costs for desulfurization technologies developed by the EIA, which were converted from a calendar year 1999 dollar basis to 2006 dollars. The EIA developed estimates for new and revamped desulfurization technologies at existing refineries.

Table 8.2 Ultra Low Sulfur Diesel (ULSD) Desulfurization Technology Costs for Individual Refineries[a,b]

Desulfurization Unit Type	Throughput (Barrels per Day)	Capital Costs (2006 Dollars per Daily Barrel Produced)	Total Capital Cost per Unit (Million 2006 Dollars)
New	50,000	1,204	60.3
New	10,000	2,187	21.9
Revamp	50,000	716	35.8
Revamp	10,000	1,464	14.6

[a] Based on cost estimates for hydrotreaters to produce ULSD.
[b] Source for this information is the Energy Information Administration
Note – A conversion factor of 1.2101 was used to convert the dollar values from 1999 to 2006 www.inflationdata.com

In its highway diesel fuel rulemaking, EPA also developed cost estimates for the deployment and implementation of desulfurization technologies at refineries. EPA estimated that it would cost existing refineries an estimated $56 million (2006 dollars) per refinery to install desulfurization technologies, and that this effort would be spread out over a 2-year time period. EPA based its conclusions on the assumption that refineries would revamp their hydrotreating technologies. It further estimated that 80% of the hydrotreaters at the refineries would be revamped. The EPA also estimated that the cost of a new hydrotreater would be $91 million (2006 dollars), and that roughly 25 refineries nationwide would have to make this investment. No estimates were made for the costs associated with new refineries as none are currently being constructed in the United States. The EPA analysis spread the investment cost over a 2-year period. Consequently, it was estimated that the US refinery-wide investment for calendar year 2004 was $2.45 billion and $2.83 billion for calendar year 2005 (EIA 2001) (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383. www.inflationdata.com).

In the August 9, 2006 edition of *This Week in Petroleum*, EIA reported that total ULSD production progress has been good and that ULSD is currently being produced in all Petroleum Administration for Defense Districts (PADDs). Stocks of ULSD in the United States in January 2007 were approximately equal to distillate oil containing greater than 500 ppm sulfur. However on the East Coast, stocks of ULSD were approximately one-third the size of distillate oil stocks containing more than 500 ppm sulfur (EIA). Another independent source, The Marathon Petroleum Company, LLC, found that 90% of refineries in the continental United States that were included in a survey had designed units capable of producing ULSD. Also, Marathon determined that the planned US capacity for ULSD would be in excess of 2.5 million barrels per day in 2006 (Marathon Petroleum Corporation 2007).

Heating Oil Cost Increases

It is assumed that the costs for retrofitting refineries will be passed on to consumers. In its December 2005 study, NESCAUM estimated that the average price increment for the lower sulfur product (500 ppm) would be $0.16 per gallon. In December 2005, this represented a 1% increase of the average oil price.

To update these costs we compared the costs of low-sulfur diesel fuel (15 – 500 ppm) with regular diesel fuel (2,000 ppm) for 2006. These data were gathered from DOE EIA Web site on March 8, 2007. We used the difference in diesel fuel prices because the cost for low sulfur heating oil is currently not reported and because diesel fuel and number 2 distillate are essentially the same product. It is therefore reasonable to assume that the cost differential between low sulfur and regular diesel fuel should reflect the potential cost differential between low sulfur and regular heating oil. All cost comparisons are before taxes. EIA only reports a low-sulfur diesel fuel category which includes both low sulfur (500 ppm) and ultra low sulfur diesel (15 ppm). For the first two months on 2007, EIA reports that stocks of 15 ppm sulfur oil were roughly twice that of 500 ppm sulfur oil. We averaged monthly costs to compute annual average costs for PADD 1A (CT, ME, MA, NH, RI, VT) and PADD 1B (DE, DC, MD, NJ, NY, PA) for low sulfur and regular diesel fuel from January to December 2006. For PADD 1A, the cost of low sulfur diesel fuel ranged from $1.954 to $2.433 per gallon and the cost of regular diesel fuel ranged from $1.963 to $2.429 per gallon. The monthly difference between low sulfur and regular diesel fuel ranged from -1.1 cents per gallon to 0.5 cents per gallon with an annual average of -0.8 cents per gallon. That is, low-sulfur diesel fuel was on average less expensive that regular diesel fuel in PADD 1A in 2006. Similarly in PADD 1B, the cost of low sulfur diesel fuel ranged from $1.894 to $2.358 per gallon and the cost of regular diesel fuel ranged from $1.894 to $2.321 per gallon. The monthly difference between low sulfur and regular diesel fuel ranged from -1.3 cents per gallon to 4.7 cents per gallon with an annual average of 1.6 cents per gallon. In both regions fuel costs were highest in the summer and the difference in cost between low sulfur and regular diesel fuel was also highest in summer. To calculate an average cost differential, we weighed the PADD 1A and PADD 1B cost differentials by residential fuel use in each PADD for 2005 (the latest date data are available from EIA). In 2005, PADD 1A States used 1.9 million gallons and PADD 1B States used 2.5 million gallons. Therefore, on average low sulfur distillate oil would be expected cost 0.8 cents per gallon more than regular heating oil in MANE-VU States. This average price differential translates in to $734/ton of sulfur removed if it assumed that the low sulfur diesel has a concentration of 500 ppm sulfur or $554/ton of sulfur removed for ultra low 15 ppm sulfur diesel.

STAPPA-ALAPCO (2006) estimates that the annual fuel oil consumption per household is 865 gallons per year. Using the price differential data presented above, the average household would spend about $7 per year additional on home heating costs by using low or ultra low sulfur fuel.

The use of LSD/ULSD will also result in cost savings to owners/operators of residential furnaces and boilers due to reduced maintenance costs. When the existing heating oil sulfur content is 2,000 ppm and 500 ppm sulfur is substituted, the service interval can be extended by a factor of three or more (e.g., cleaning at three year intervals rather than annually). Vacuums are used to remove deposition caused by SO_2 from furnaces and boilers.

The potential vacuum cleaning costs savings for the United States, for a starting fuel sulfur content of 2,000 ppm ranges from approximately $200 million a year to $390 million a year for service costs of $50 to $100 per hour. Therefore, if all oil heated homes switched to 500 ppm sulfur heating oil, more than $200 million a year could be saved, which would significantly lower the overall operating costs of fuel oil marketers. Given the dominant share of the U.S. heating oil market represented by the Northeast States, a large percentage of the projected national benefits would accrue in the region (NESCAUM 2005). In a brochure distributed by EIA titled *Residential Heating Oil Prices: What Consumers Should Know,* EIA reports that 6.3 million of the 8.1 million households using heating oil in the United States (78%) are in the Northeast Region. This region includes the New England and Central Atlantic States.

Heating Oil Supply

EPA addressed the issue of using ULSD for heating oil purposes in its regulatory impact analysis for Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (2000). EPA found that refiners in the Mid-Atlantic and Northeast (PADD 1) could produce more of this fuel and reduce the need for imports.

EIA reports that in 2004, 5,975,966,000 gallons of heating oil were sold in the United States. This decreased to 5,548,827,000 gallons in 2005. The EIA publishes weekly updates on the availability of heating oil. Information was retrieved for January 2007 and is summarized in Table 8.3 below.

Table 8.3 Average January 2007 Distillate Stocks (Million Barrels)[a]

Location	15 ppm and Under Stocks	15 ppm -- 500 ppm Stocks	>500 ppm Stocks	Total Distillate Stocks
US (Total)	57.2	25.0	59.7	141.8
East Coast	14.7	21.9	44.5	66.5
Average Days of Supply of Distillate Fuel Oil[b]	34.4	34.4	34.4	34.4

[a] Source for this information is the Energy Information Administration.
[b] The sulfur content of distillate stocks is not distinguished by the EIA for this data point.

The EIA also makes available information regarding the production and imports of heating oil. This information is summarized in Table 8.4, and includes specific data for the East Coast.

The information presented in Table 8.4 indicates that on a nationwide basis, more ULSD is produced than both LSD and high sulfur fuel. This is due to the predominant use of ULSD in highway diesel vehicles. This information also supports the conclusion that the United States has the infrastructure to produce adequate stocks of LSD and ULSD.

Table 8.4 Distillate Production and Imports (Million Barrels per Day)[a,b]

Location	15 ppm and Under Production	15 ppm - 500 ppm Production	>500 ppm Production	Total Distillate Production
US	2.659	0.624	0.970	4.253
East Coast	0.248	0.024	0.277	0.549
Imports	0.204	0.018	0.115	0.392

[a] Source for this information is the Energy Information Administration.
[b] Based on the four week average ending January 12, 2007.

Currently, the 15 ppm fuel is sold for highway use diesel, whereas the >500 ppm stocks are sold for heating oil. The 15-500 ppm fuel can still be used until 2010 under the hardship provisions of the heavy duty highway diesel program (EPA 2004). Under these provisions of the heavy duty highway diesel program, if there is a shortage of 15 ppm fuel, the 15 -500 ppm fuel could be used to relieve the shortage. With this flexibility, the likelihood of a fuel shortage in the short term, due to usage of ULSD for heating oil is reduced.

Time Necessary for Compliance

Refiners in the United States are already producing low sulfur highway diesel fuel. This same fuel can be marketed as heating oil since it is the same refinery product as highway diesel except with dye added to the fuel to differentiate it for tax purposes. Some time may be required to allow petroleum marketers to adjust to distributing ULSD to heating oil customers, however, the distribution network for motor fuels and heating oil are already in place.

NESCAUM (2005) estimated that during peak periods of demand, up to 20% of the required heating oil is imported. This analysis does not address whether offshore refineries should be able to produce 15 ppm sulfur for export to the Northeast United States. In case of a shortage of 15 ppm fuel during the transition period from LSD to ULSD, the heavy duty highway diesel program allows the use of 15-500 ppm sulfur fuel.

Existing residential furnaces and boilers do not need to be retrofitted or modified to combust 15 ppm sulfur. The capacity for producing LSD and ULSD already exists among US refiners. Consequently, the time necessary for compliance does not hinge on the heating oil furnace/boiler.

Energy and Non-Air Impacts

Reducing the sulfur contents of heating oil has a variety of beneficial consequences for residential furnaces and boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings. According to a study conducted by the New York State Energy Research and Development Authority, (NYSERDA), boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. These reductions in buildup of deposits result in longer service intervals between cleanings. (Batey and McDonald 2005). Batey and McDonald (2005) estimated that the potential cost savings from decreased vacuum cleanings ranges from $200 million per year to $390 million per year. The decreased deposits would also enable a more efficient transfer of heat, thereby reducing the fuel usage. Further reducing the heating oil sulfur from 500 to 15 ppm would increase the cost savings from decreased maintenance needs due to heat exchanger fouling.

The decreased sulfur levels would enable manufacturers to develop more efficient furnaces and boilers by using more advanced condensing furnaces and boilers. These boilers recoup energy that is normally lost to the heating of water vapor in the exhaust gases. Historically, the use of high sulfur fuels prevented this due to the corrosion of the furnace/boiler due to the creation of sulfuric acid in the exhaust gases. The increased efficiency results in a decrease in the amount of heating oil a heating unit uses, therefore, this would make a switch to lower sulfur heating oils more attractive and cost effective.

Remaining Useful Life of the Source

Residential furnaces and boilers have finite life times, but they do not need to be replaced to burn low or ultra low sulfur fuel. The Energy Research Center estimates that the average life expectancy of a residential heating oil furnace is approximately 18 years, and that the average life expectancy of a residential heating oil boiler is 20-25 years (Personal communication with Mr. John Batey, Energy Research Center on February 6, 2007).

Finally, the number of homes that are being heated with heating oil is declining by approximately 100,000/year (RedOrbit 2007). No geographical distribution was available for this estimate, but since heating oil is predominantly used in the Northeast, most of the changes will be occurring there. Consequently, emissions from heating oil combustion will become less significant of a source of SO_2 emissions in the future.

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CHAPTER 9

RESIDENTIAL WOOD COMBUSTION

BACKGROUND

The MANE-VU Contribution Assessment and other MANE-VU reports have documented that visibility impairment in this region is primarily due to regional secondary sulfate. However, in the MANE-VU Class I areas, biomass combustion also has been identified as a contributor to visibility impairment. Biomass combustion emissions due to human activity primarily derive from residential wood combustion. While some biomass burning occurs throughout the year, residential wood combustion occurs predominantly in the winter months, potentially contributing to wintertime peaks in PM concentrations.

In the document, *Control Analysis and Documentation for Residential Wood Combustion in the MANE-VU Region*, OMNI Environmental Services, Inc. (OMNI) conducted a control analysis and documentation of residential wood combustion (RWC) in the 11 States and the District of Columbia that make up the MANE-VU region. Information for the OMNI analysis was obtained from: (1) The MANE-VU Residential Wood Combustion Emission Inventory published by MARAMA (July 2004 report), (2) Residential Energy Consumption Surveys published by the EIA, (3) the National Emission Inventory published by the EPA, (4) Simmons Marketing Research reports, and (5) American Housing Surveys for the United States published by the U.S. Department of Commerce and the U.S. Department of Housing and Urban Development. In addition, the results of three RWC surveys at the State-level have been published in the last decade for the Mid-Atlantic and New England area, which allow for comparison of data extrapolated from the national- and regional-scale surveys to the State level for three States. These were the: (1) 1995 Delaware Fuelwood Survey, (2) Residential Fuelwood Use in Maine, Results of 1998/1999 Fuelwood Survey, and (3) Vermont Residential Fuel Wood Assessment for 1997-1998.

To facilitate understanding of the cost effectiveness analyses done by OMNI, descriptions of the various appliances used, as well as a brief discussion of efficiency, are provided from the OMNI report.

Cordwood-Fired Stoves and Fireplace Inserts

Uncertified, certified catalytic, and certified non-catalytic cordwood stoves and fireplace inserts together are considered cordwood heaters. They are designed to burn bulk cordwood and are room space heaters, i.e., they primarily rely on radiant and convection heat transfer, in contrast to centralized heating systems such as warm-air furnaces or boilers which utilize heat distribution systems to heat multiple rooms. Fireplace inserts are essentially wood stoves that are designed to be inserted into an existing fireplace cavity. Because of the heat transfer shielding effect of the fireplace cavity and the fact the majority of existing fireplace chimneys are against an outside wall, their heating efficiency is less than a similar freestanding woodstove. Many fireplace inserts have fans to facilitate transfer of heat from the portion that is inside the fireplace cavity. Both freestanding cordwood stoves and fireplace inserts rely on a natural draft using room air for combustion and the venting of exhaust through the chimney to the atmosphere. Though the majority of cordwood heaters use room air for combustion, some insert installations, such as in mobile homes, require the use of outside air for combustion.

Uncertified Conventional Cordwood-Fired Stoves and Fireplace Inserts
Uncertified cordwood fired stoves and fireplace inserts include units manufactured before the 40 CFR Part 60, Subpart AAA New Source Performance Standard (NSPS) July 1, 1990 certification requirement, and currently or recently manufactured exempt units which operate similarly to some old pre-EPA certification units.

NSPS Certified Catalytic Cordwood-Fired Stoves and Fireplace Inserts
Certified catalytic units pass the exhaust through a catalyst to achieve emission reductions. Generally, a coated ceramic honeycomb catalyst is located inside the stove where the incompletely combusted gases and particles ignite and are combusted further, thus reducing air emissions and increasing combustion overall efficiency.

NSPS Certified Non-Catalytic Cordwood-Fired Stoves and Fireplace Inserts
Certified non-catalytic stoves and fireplace inserts rely on design features to reduce air emission and increase efficiency. They generally rely on the introduction of heated secondary air to improve combustion, as well as firebox insulation, and baffles to produce a longer, hotter gas flow path, as well as other design features to achieve low emissions and higher efficiency.

Pellet Stoves and Fireplace Inserts

Analogous to cordwood stoves and fireplace inserts, pellet stoves and fireplace inserts are considered room heaters. They burn pellets generally made from sawdust, although there has been, and continues to be, research into utilizing other biomass fuels to make pellets. Combustion air is drawn from the room for most models, and exhaust is vented outdoors. Some pellet appliances use outside air for combustion. Pellet stoves and inserts require the use of electric motors to power the combustion air and heat transfer fans and the pellet-feeding auger. Modern pellet units use electronic sensors and controls. Pellets are introduced into the hopper, and the auger continuously feeds a consistent amount of pellets into the firebox. The feed rate is controlled electronically by a feed rate setting selected by the user. There are two basic designs: bottom-feed and top-feed models. Pellet units have a high efficiency and low emissions due to the use of the electric auger and fan that produce uniform and controlled combustion conditions. Some units are certified by the NSPS process and some are not. The performance of the certified and uncertified models are similar. What is considered by most as a “loop-hole” in the NSPS regulations essentially allows certification to be bypassed.

Wood-burning Fireplaces without Inserts

Fireplaces without inserts include manufactured units (often referred to as “zero-clearance” fireplaces) and site-built masonry units operated both with and without glass doors. Combustion air is drawn from the natural draft created by fire, and that same draft vents the exhaust gases through the chimney. Fireplaces without inserts have low efficiencies due to the large amount of heated room air that is exhausted out of the chimney from the draft. Many fireplaces without inserts are not used in a given year, some are used for aesthetic purposes and some are used for heating. Those that are used for heating are almost always used for secondary heating purposes and not primary heating due to their low efficiency and lack of heat transfer capabilities. Manufactured wax/fiber firelogs are often used as a fuel in them with about 30% of fireplace users nationwide claiming that they use wax/fiber firelogs some of the time. Most fireplaces are wall-mounted, however, this category also includes some free-standing models.

Direct Vent Gas Stoves and Fireplace Inserts (LPG and Natural Gas)

Direct vent gas stoves and inserts are sealed units that draw their combustion air from, and vent their exhaust to, the outside air. Venting can be extended vertically or horizontally out of the home. A common type of venting is coaxial, which has the exhaust pipe contained within the air inlet pipe, so the temperature of the combustion air is raised, and the temperature of the exhaust is lowered, creating more efficient combustion. It should be noted that natural gas is not readily available in all locations, however LPG may be available for use.

Vent-Free Gas Stoves and Fireplace Inserts (LPG and Natural Gas)

Vent-free gas stoves and inserts receive their combustion air from the room in which the unit is placed, and all of the products of combustion are exhausted into the room as well. The high efficiency of vent free units is due to the fact that the heat produced is kept in the room. Vent free gas stoves and inserts have a maximum heat input in order to avoid emitting excess CO, CO_2, or NO_X into the room, and the units also have an O_2 depletion sensor or other device to shut the unit down if oxygen levels become too low. It is important to note that vent-free natural gas and LPG stoves, inserts and log sets should not be considered options for primary or even significant secondary heating use. There is considerable concern regarding indoor air quality and damage to homes by moisture created from their use, as combustion gases are not vented to the atmosphere. If the devices are used prudently, these problems are reduced. Their appropriate role is for aesthetics and minor secondary heating. Just as with direct vent gas stoves and fireplace inserts, LPG can be used as an alternative where natural gas is not readily available.

B-Vent Gas Stoves and Fireplace Inserts (LPG and Natural Gas)

B-vent gas stoves and inserts draw their combustion air from the room, and exhaust is vented outdoors. These units use a draft hood for the proper venting of exhaust. B-vent gas stoves and inserts have lower efficiency than direct vent due to the fact that already heated room air is used as combustion air, which is then exhausted to the outdoors, taking heat away from the room.

OMNI Study Summary

In the OMNI study, the amount of fuel consumed by RWC devices was considered the measure of activity. Activity data were provided by individual appliance type by State and for the total MANE-VU region. The activity study conducted by OMNI showed that there were approximately 6.4 million tons of fuel burned in 2002 by RWC devices in the MANE-VU region. The majority of RWC combustion was located in New York (1.9 million tons of fuel burned) and Pennsylvania (1.4 million tons of fuel burned).

OMNI then compiled an emissions inventory by county, by State, and for the entire MANE-VU region for the 2002 base year. The dry mass of fuel (activity) for cordwood, pellets, and manufactured wax/fiber firelogs compiled in the activity task was multiplied by the applicable emission factor in the units of mass air pollutant per mass of dry fuel. The emission factors were obtained by reviewing and averaging (if multiple sources were available) data obtained from available reports and publications. PM and VOC (an ozone precursor) are the main criteria pollutants of concern for RWC and non attainment areas. The OMNI emissions inventory reported that there were 92,470 tons of total PM emissions and 87,741 tons of VOC generated from RWC devices in the MANE-VU region during the base year (2002). It should be noted that this analysis assumed that PM_{10} was equivalent to PM. The only emissions control efficiency, and control device information available is for PM_{10}. We have therefore assumed that data for PM_{10} are applicable to $PM_{2.5}$.

Table 9.1 from the OMNI report summarizes measures for RWC RACM developed by EPA in EPA-450/2-89-015. OMNI reported the RACM fall in three primary categories: (1) improvement of performance, (2) reducing the use of RWC devices, and (3) episodic curtailment. The effectiveness in reducing RWC emissions and a related discussion of each of the various activities are also provided in Table 9.1. In addition to the three primary categories for RWC RACM, the RACM document emphasizes the importance of public awareness in many RWC emission control programs and provides considerable information on the subject.

Table 9.1 Summary of Measures Available for RWC RACM – PM_{10}

Program Elements	**Estimated Effectiveness (%)**	**Discussion**
IMPROVEMENT OF PERFORMANCE		
State implementation of NSPS	0	States are not expected to adopt this program element at levels that would affect program effectiveness significantly.
Ban on resale of uncertified devices	0	No credit recognized because requirement is largely unenforceable: other elements will be required to include disabling of retired used devices.
Installer Training Certification or Inspection Program	~ 5	Reduction in emissions from each new certified RWC device where either the installer is trained/certified or the installation is inspected.
Pellet stoves	90	Reduction in emissions from each new or existing conventional, uncertified RWC device replaced with a pellet stove.
	75	Reduction in emissions from each new or existing Phase II EPA certified RWC device replaced with a pellet stove.
EPA Phase II certified RWC devices	~50	Reduction in emissions from each new or existing conventional, uncertified RWC device replaced with an EPA Phase II certified RWC device.
Retrofit requirement	<5	Reduction in emissions from each existing conventional, uncertified RWC device equipped with a retrofit catalyst or pellet hopper (to maximum when all existing uncertified RWC devices have retrofit devices installed).
Accelerated changeover requirement	~50	Reduction in emissions from each existing conventional, uncertified RWC device replaced with Phase II certified device.
	100	Reduction in emissions from each existing conventional, uncertified RWC device removed and not replaced: requires existing device to be disabled and not resold.
Accelerated changeover inducement	~50	Reduction in emissions from each existing conventional, uncertified RWC device replaced with Phase II certified device.
	100	Reduction in emissions from each existing conventional, uncertified RWC device removed and not replaced: requires existing device to be disabled and not resold.

Table 9.1 Summary of Measures Available for RWC RACM – PM_{10}

Program Elements	Estimated Effectiveness (%)	Discussion
Require fireplace inserts	0	No credit recognized for fireplace inserts, since inserts change use of fireplace from aesthetic to primary heat source, resulting in an increase in amount of wood combusted and higher overall emissions.
Wood moisture	<5	Reduction in total emissions from all RWC devices in the community/airshed.
Trash burning prohibition	0	No credit recognized for eliminating trash burning in RWC devices.
Weatherization of residences	<5	Reduction in total emissions from all RWC devices in the community/airshed.
Opacity limits	<5	Reduction in total emissions from all RWC devices in the community/airshed.
REDUCING USE OF RWC DEVICES		
Availability of alternative fuels	100	Reduction in emissions from each RWC device removed from service and replaced with device using natural gas: recognize no more than 10% of RWC devices replaced under program with no additional incentives.
Emission trading	Computation required	For a 2:1 trading ratio, the reduction in emissions from each new stove would be calculated as the difference between emissions of a new RWC device and 2 times the average emissions per stove in the community: multiplier would change for other trading ratios.
Taxes on RWC devices	Variable	Emission reduction credit would vary with utility or tax rate structure adopted and extent to which this structure resulted in reduction in number of RWC devices in the community versus reduction in use of RWC devices.
Regulatory ban on RWC devices in new dwellings	100	Reduction in emissions from new RWC devices purchased for installation in new dwellings.
Regulatory ban on existing RWC devices	100	Reduction in emissions from each RWC device removed.

Table 9.1 Summary of Measures Available for RWC RACM – PM_{10}

Program Elements	Estimated Effectiveness (%)	Discussion
EPISODIC CURTAILMENT		
Voluntary	10	Reduction in emissions for all RWC devices not exempted.
Mandatory	60% fireplace 50% woodstoves	Reduction in emissions for all RWC devices not exempted.

Table Reference: U.S. EPA, 1992, *Technical Information Document for Residential Wood Combustion Best Available Control Measures*, Research Triangle Park, NC, EPA-450/2-92-002.

Table 9.2 from the OMNI report summarizes measures for RWC BACM developed by EPA in EPA-450/2-92-002. As shown in Table 9.2, the BACM fall into two primary categories: (1) integral measures which are necessary for the success of a long-term RWC pollutant reduction programs but, by themselves, are not adequate to provide long-term reductions and (2) flexible (long-term) measures to reduce, eliminate, or prevent increases in pollutant emissions for existing and/or new installations. With the exceptions of the device and upgrade offsets, the specific elements of the BACM are essentially those described in the RACM document with the various efficiencies listed in Table 9.1 being applicable.

Table 9.2 Summary of Measures Available for RWC BACM – PM_{10}

Integral Measures[1]	Flexible Measures that Reduce or Eliminate Emissions from Existing Installations[2]	Flexible Measures that Reduce Emissions or Prevent Emission Increases from New Installations[2]	Flexible Measures that Reduce Emissions from New and Existing Installations[2]
1. Public awareness and education.	1. Conversion of existing wood-burning fireplaces to gas logs.	1. Gas fireplaces or gas logs in new wood burning fireplace installations.	1. Device offset.[4]
2. Mandatory curtailment during predicted periods of high PM_{10} concentrations.	2. Changeover to EPA certified, Phase II stoves or equivalent.	2. Upgrade offset.[4]	2. Upgrade offset.[4]
3. All new stove installations EPA-certified, Phase II stoves or equivalent.	3. Changeover to low emitting device.[3]	3. Restriction on number and density of new wood-burning stove and/or fireplace installations.	

Table 9.2 Summary of Measures Available for RWC BACM – PM_{10}

Integral Measures[1]	**Flexible Measures that Reduce or Eliminate Emissions from Existing Installations**[2]	**Flexible Measures that Reduce Emissions or Prevent Emission Increases from New Installations**[2]	**Flexible Measures that Reduce Emissions from New and Existing Installations**[2]
4. Measures to improve wood burning performance: -control of wood moisture content -weatherization of homes with wood stoves -educational opacity program		4. Requirement that new stove installations be low emitting.	

[1] Integral measures are regarded as critical for the success of a RWC control program, but by themselves are not intended to result in long-term attainment of the PM_{10} NAAQS for serious PM_{10} nonattainment areas.

[2] Flexible measures are designed for permanent control of RWC emissions and thus long-term attainment of the PM_{10} NAAQS.

[3] This measure is virtually identical to item 2, except that the changeover is recommended to a “low-emitting” device that can document “in-home” field test emissions less than the emission factor averages of “in-home” field test emissions data for EPA-certified stoves. This can include classes of devices that are demonstrated to be capable as a class of producing lower field emissions, as well as, specific model units that perform better in the field than the class collectively (an example might include masonry heaters, uncertified pellet-fueled devices, and wood fired gasification centralized heating systems).

[4] Offsets are intended to achieve emission reductions, when retiring (device offset) or changing-out (upgrade offset) conventional stoves, greater than the emissions increase resulting from new stove installations.

Table Reference: U.S. EPA, 1992, *Technical Information Document for Residential Wood Combustion Best Available Control Measures*, Research Triangle Park, NC, EPA-450/2-92-002.

OMNI reported that the RWC RACM and BACM have been the basis for PM_{10} innovative strategies implemented in various western States and in local jurisdictions and have also been, in-large part, the basis for a number of western State and their local RWC regulations. As part of these strategies, strict particulate emission standards have been developed which will take effect in 2008.

The OMNI report states that the Washington State standard is notable among State and local regulations for residential wood burning devices. Washington State has implemented more stringent standards for residential wood burning devices, so devices installed in Washington State must be certified to the more stringent standard. This has affected the stove market because many U.S. certified stove manufacturers choose to have their appliances certified to the more stringent Washington State standard, unless the manufacturer can not or does not choose to test to the tighter standard. Discussions with EPA indicate that most manufacturers are choosing to design and sell units that meet the Washington State standards of 4.5 g/hr for non catalytic wood stoves and 2.5 g/hr for catalytic wood stoves (personal communication with Mr. John Dupree of the U.S. EPA).

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR RESIDENTIAL WOOD COMBUSTION

Cost of Compliance

OMNI analyzed the cost effectiveness of five categories of widely existing, older technology wood-burning devices. These are: (1) freestanding cordwood stoves, (2) cordwood-fueled fireplace inserts, (3) cordwood fireplaces (without inserts) used for heating purposes, (4) centralized cordwood heating systems and (5) cordwood fireplaces used for aesthetic purposes. Table 9.3 lists these five categories with the available, improved technology replacement, installation scenarios, and fuel switching alternatives that would reduce particulate and VOC emissions.

OMNI noted that wood resources are abundant and widely utilized as fuel, and heating is essential due to the climate of the region. The cost to households of any regulatory program mandating acceptable heating practices is an important consideration. Likewise, the cost to households of any voluntary program is paramount for its success. The cost effectiveness of all reasonable scenarios for the replacement, modification or alternative fuel use for older existing, high emission wood-burning appliances was provided in the OMNI report for regulators and policy makers charged with the task of specifically lowering particulate and VOC emissions from residential wood combustion.

The tables provided in this chapter based on the OMNI report allow for a direct comparison of the cost burden for each realistic mitigation option that would be shouldered by residential users. As an example, for an average resident in the MANE-VU region with an existing older technology centralized cordwood heating system, the best current option in terms of cost among the pellet, natural gas, and LPG options, is natural gas (assuming natural gas is available). Similarly, for wood-burning fireplaces used for aesthetics, manufactured wax/fiber firelogs offer the lowest cost per unit mass of air pollutant reduction. The cost effectiveness of each option is dependent on the costs of the new equipment and the cost of required fuels. The costs presented in the tables in this chapter were the most current information available as of the date of the OMNI report.

Estimates of costs per ton of reductions in the tables in this chapter are specific to the MANE-VU region because they reflect the estimated usage of various devices in this region.

Table 9.3 Improved Technologies and Fuel Alternatives

Existing Cordwood Device	High Technology Replacement, Installation or Alternative Fuel
Uncertified Freestanding Cordwood Stove	Replacement with Certified NSPS Non-Catalytic Cordwood Stove
	Replacement with Certified NSPS Catalytic Cordwood Stove
	Replacement with Pellet Stove
	Replacement with Gas Stove – natural gas (B vent, direct vent)
	Replacement with Gas Stove – LPG (B vent, direct vent)
Uncertified Cordwood Fireplace Insert	Replacement with Certified NSPS Non-Catalytic Cordwood Insert
	Replacement with Certified NSPS Catalytic Cordwood
	Replacement with Pellet Insert
	Replacement with Gas Insert – natural gas (B vent, direct vent)
	Replacement with Gas Insert – LPG (B vent, direct vent)
Cordwood Fireplace without Insert Used for Heating	Installation of Certified NSPS Non-Catalytic Cordwood Insert
	Installation of Certified NSPS Catalytic Cordwood Insert
	Installation of Pellet Insert
	Installation of Gas Insert – natural gas (B-vent, direct vent)
	Installation of Gas Insert – LPG (B-vent, direct vent)
Cordwood Fireplace Used for Aesthetic Purposes	Installation of Gas Log Set – natural gas (vented and vent free)
	Installation of Gas Lo g Set – LPG (vented and vent free)
	Wax/Fiber Firelog Fuel
Centralized Cordwood Heating System	Pellet Furnace or Boiler
	Gas Furnace or Boiler – natural gas
	Gas Furnace or Boiler – LPG

OMNI Environmental Services, Inc. *Task 6, Technical Memorandum 4 (Final Report), Control Analysis and Documentation for Residential Wood Combustion in the MANE-VU Region*. Project funded by Mid-Atlantic Regional Air Management Association, Inc., December 19, 2006.

Table 9.4 from the OMNI report demonstrates the cost effectiveness of replacing three types of cordwood stoves and fireplaces with devices that emit less PM. Table 9.5 from the OMNI report demonstrates the impact on cost effectiveness of the same replacements on VOC reductions. The cost effectiveness tables are in reference to the replacement of an existing RWC device, and do not include new construction.

In Tables 9.4 and 9.5, if the total annual cost of the improved technology and alternative fuel replacement or installation is less than the total annual cost of the existing device, and there is corresponding pollutant reduction after installation or replacement, then there is no cost for the pollution reduction, and the cell is marked as "**". The replacement options for which there is no cost may actually represent cost savings, and thus are the most cost effective options for replacement.

Table 9.4 PM Reduction Cost Effectiveness for Replacement of Existing Uncertified Freestanding Cordwood Stove/Insert and Cordwood Fireplace w/o Insert for Heating

Existing Cordwood Device	Certified NSPS Non-Catalytic Cordwood Stove	Certified NSPS Catalytic Cordwood Stove	Pellet Stove	Gas Stove-NG, B Vent	Gas Stove-NG, Direct Vent	Gas Stove-LPG, B Vent	Gas Stove-LPG, Direct Vent
	PM Reduction Cost Effectiveness ($/ton)						
Uncertified Freestanding Cordwood Stove	1,170	3,300	8,960	5,350	3,530	12,600	9,760
Uncertified Cordwood Fireplace Insert	**	**	5,180	1,910	**	8,980	6,040
Cordwood Fireplace w/o Insert for Heating	3,880	5,670	8,330	**	**	1,880	695

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**No cost for the pollution reduction.

Tables 9.4 and 9.5 indicate that OMNI estimated that in the MANE-VU region there are several options for reducing emissions from two of the above types of fireplaces that would reduce emissions at essentially no cost, due to fuel cost savings.

Table 9.5 VOC Reduction Cost Effectiveness for Replacement of Existing Uncertified Freestanding Cordwood Stove/Insert and Cordwood Fireplace w/o Insert for Heating

Existing Cordwood Device	Certified NSPS Non-Catalytic Cordwood Stove	Certified NSPS Catalytic Cordwood Stove	Pellet Stove	Gas Stove-NG, B Vent	Gas Stove-NG, Direct Vent	Gas Stove-LPG, B Vent	Gas Stove-LPG, Direct Vent
	VOC Reduction Cost Effectiveness ($/ton)						
Uncertified Freestanding Cordwood Stove	1,260	2,960	7,740	4,940	3,260	11,800	9,130
Uncertified Cordwood Fireplace Insert	**	**	4,480	1,760	**	8,410	5,640
Cordwood Fireplace w/o Insert for Heating	7,900	10,400	13,200	**	**	3,090	1,140

OMNI Environmental Services, Inc. *Task 6, Technical Memorandum 4 (Final Report), Control Analysis and Documentation for Residential Wood Combustion in the MANE-VU Region*. Project funded by Mid-Atlantic Regional Air Management Association, Inc., December 19, 2006.

**No cost for the pollution reduction.

Table 9.6 presents the cost effectiveness in terms of dollars per ton of PM reduction and VOC reduction for replacement of an existing centralized cordwood heating system with three available technologies. The cost effectiveness tables are in reference to the replacement of an existing RWC device, and do not include new construction. The most cost effective option is replacing the existing system with a natural gas furnace or boiler. This option is not feasible in areas that do not have access to natural gas, and the increase in costs associated with using LPG is significant.

Table 9.6 Reduction Cost Effectiveness for the Replacement of an Existing Centralized Cordwood Heating System

High Technology Replacement, Installation or Alternative Fuel	PM Reduction Cost Effectiveness ($/ton)	VOC Reduction Cost Effectiveness ($/ton)
Pellet Furnaces and Boilers	7,810	17,200
Gas Furnaces and Boilers–Natural Gas	3,030	7,150
Gas Furnaces and Boilers-LPG	9,370	23,100

OMNI Environmental Services, Inc. *Task 6, Technical Memorandum 4 (Final Report), Control Analysis and Documentation for Residential Wood Combustion in the MANE-VU Region*. Project funded by Mid-Atlantic Regional Air Management Association, Inc., December 19, 2006.

Table 9.7 presents the cost effectiveness in terms of dollars per ton of PM reduction and VOC reduction for the addition of a gas log set or use of wax/fiber firelogs in an existing fireplace with no insert. Burning wax/fiber firelogs in the existing fireplace is, by far, the most cost effective option for reducing emissions of PM and VOC.

Table 9.7 Pollutant Reduction Cost Effectiveness for the Addition of a Gas Log Set or Use of Wax/Fiber Firelogs in an Existing Fireplace w/o Insert Used for Aesthetics

	Pollutant Reduction Cost Effectiveness ($/ton)				
Pollutant	**Vent-Free Gas Log Set-NG**	**Vented Gas Log Set-NG**	**Vent-Free Gas Log Set-LPG**	**Vented Gas Log-LPG**	**Wax/Fiber Firelog Fuel**
PM	27,100	29,900	29,400	34,100	2,530
VOC	43,900	48,500	48,300	56,600	5,110

OMNI Environmental Services, Inc. *Task 6, Technical Memorandum 4 (Final Report), Control Analysis and Documentation for Residential Wood Combustion in the MANE-VU Region*. Project funded by Mid-Atlantic Regional Air Management Association, Inc., December 19, 2006.

OMNI presented no cost-effectiveness summary for other RWC control measures such as described in EPA's PM_{10} RACM/BACM guideline documents. Costs associated with these measures are predominantly organizational and administrative associated with the implementation of regulations.

Time Necessary For Compliance

Because the control methods discussed in the previous section for RWC are existing technology, the time necessary for compliance would depend on the amount of time it would take to regulate the sources and establish compliance deadlines. The *Feasibility Assessment of a Change-out/Education Program for Residential Wood Combustion* from the Canadian Council of Ministers of the Environment suggests a phased approach for national implementation. A phased approach will enable the program to evolve over time and benefit from lessons learned in the early stages of the program. Phasing also reflects the reality that building awareness and changing behavior is a long-term investment. The approach that this report proposed had two phases. The first phase (2005-2006) focused on building a base for support and understanding around RWC in a single province. The second phase (2007 and beyond) and full roll-out involved the realization of independent, arms length management of public education and outreach by all stakeholders throughout Canada. The main steps for this phase included:

- Implementation of national regulation as soon as possible (i.e. 2008-2009);
- Full operational capacity across Canada;
- Funding to come from multiple sources (i.e. nationwide partnerships with the insurance, financial, and utilities industries);
- Movement of various groups from being target audiences to becoming key players in designing and delivering woodstove change-out/public education campaigns; and
- Multi-stakeholder involvement and shared leadership (governments together with business and industry, communities, and non-governmental organizations).

Energy and Non-Air Impacts

Other factors beyond $PM_{2.5}$ and regional haze (i.e., VOC and fine particles) should also influence RWC regulatory policy. The greenhouse gas benefits of biomass combustion and the minimal acid gas emissions (acid precipitation impacts) from wood combustion are strong environmental advantages. Further, the fact that wood is a domestic renewable energy source and the fact that the cost of natural gas, propane, and fuel oil have a history of rising together have been responsible for the increase in the use of RWC. For example, several States are encouraging the use of renewable energy sources such as wood for heating purposes.

The Canadian Council of Ministers of the Environment study estimated that the increase in combustion efficiency associated with a switch out to a more efficient stove would save on average more than one cord of wood per stove per heating season.

Any mandatory change out program should be mindful that even with assistance, woodstove change out programs will impact families that are least able to bear the burden of additional costs. Voluntary programs do not impose this economic burden on families less able to bear associated costs.

Remaining Useful Life Of The Source

From information obtained from a scoping study that was prepared for Environment Canada in 1997, (Gulland Associates Inc., 1997) the durability of low emission stoves has improved considerably. Premature stove degradation is not viewed as a problem. In most new stoves today, vulnerable parts can be replaced, and manufacturers now use more heat-resistant materials such as ceramics and stainless steel. The performance and durability of catalytic stoves has also improved through better design and use of materials. The useful life of a wood stove catalytic element is estimated to be 9,000 to 12,000 hours, or three to five years of use, depending on heating demand, user skill, and degree of maintenance provided.

The best mechanism by which to lower smoke emissions from residential wood burning appliances is to replace conventional equipment with certified low emission stoves. Given the minimum useful life span of a wood stove of 10-15 years (per industry references), over which time the incremental cost of advanced technologies is spread, the cost impacts did not seem unreasonable to Environment Canada. It is also possible that the price of the least expensive advanced technology stove would come down after a regulation were established as manufacturers seek to fill the low cost market niche formerly filled by conventional stoves; that is, plain, unadorned styling and lacking additional features such as ash pan and large glass door panel. (Gulland Associates Inc., 1997) Many woodstove manufacturers have chosen to manufacture products at a reasonable cost that meet more stringent emissions standards such as those in Washington State (personal communication with Mr. John Dupree of EPA). Implementation of stricter emissions standards in additional states or regions will likely increase the competition to produce these woodstoves at even more reasonable prices.

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CHAPTER 10

RESIDENTIAL WOOD COMBUSTION - OUTDOOR WOOD-FIRED BOILERS

BACKGROUND

Outdoor wood-fired boilers are used in the Northeast United States, and their use is increasing as more traditional heating fuels (heating oil, natural gas) are becoming more expensive. NESCAUM (2007) estimates that the sale of outdoor wood-fired boilers is increasing by 25-50% annually. Nationwide there are between 155,000 and 200,000 boilers in service (Personal communication with Lisa Rector, NESCAUM). If the sales trends continue, NESCAUM estimates that there may be up to 500,000 boilers nationally by 2010.

Outdoor wood-fired boilers are used for heating and providing hot water for both individual homes and for “mini-district heating” (Woodheat.org 2007). Additional uses of outdoor wood-fired boilers include heating swimming pools and greenhouses. Outdoor wood-fired boilers are typically located in sheds that are located near buildings. Heated water is conveyed through underground or insulated pipes.

Even though outdoor wood-fired boilers may be economical solutions to home heating and hot water production, they contribute significantly to air pollution. Outdoor boilers emit so much smoke they have been banned by some local jurisdictions (Woodheat.org 2007). NESCAUM (2007) estimates that the average fine particulate emissions from one outdoor wood-fired boiler are equivalent to the emissions from 22 US Environmental Protection Agency (EPA) certified wood stoves, 205 oil-fired furnaces, or 8,000 natural gas-fired furnaces.

On the basis of heat input, NESCAUM (2007) estimated that outdoor wood-fired boilers emit from 1.5 to 3.1 pounds of PM per MMBTU heat input. This information was calculated by NESCAUM using data from tests conducted on outdoor wood-fired boilers for EPA (EPA 1998a). (Guldberg 2007) used data from 56 outdoor wood-fired boilers tests conducted by EPA in 1995 and 1999, and estimated that outdoor wood-fired boilers emit 1.44 pounds of PM per MMBTU heat input. In comparison, the EPA estimate (EPA 1998b) for PM from residential fuel oil combustion is 0.4 pounds of PM per thousand gallons of fuel combusted. Assuming a heating value of 140 MMBTU per thousand gallons of fuel oil, the PM emission factor is 0.003 pounds of PM per MMBTU heat input for residential fuel oil combustion. Similarly, for residential natural gas combustion, (EPA 1998c) assuming a natural gas heating value of 1,020 BTU per standard cubic foot, the PM emission factor is 0.002 pounds per MMBTU heat input. Based on these emission factor estimates, and strictly on the basis of heat input, outdoor wood-fired boilers emit roughly 500 times as much PM as oil-fired residential furnaces and 750 times as much PM as natural gas-fired residential furnaces based on the low-range estimate of PM emissions from outdoor wood-fired boilers. Based on the upper range of the PM emissions estimate from outdoor wood-fired boilers, they emit roughly 1,000 times as much PM as oil-fired residential furnaces and 1,500 times as much PM as natural gas-fired furnaces.

Heavy emissions from outdoor wood-fired boilers can be attributed to their designs. For example, most outdoor wood-fired boilers have fireboxes that are surrounded by a water jacket. The water jacket makes complete combustion of the wood nearly impossible due to the cooling effect that the jacket has on the firebox. The flaming combustion of wood cannot occur below about 540 C (1,000 F), so the steel surfaces of the water jacket backed up by water at approximately 65 C (150 F) chill and quench the flames well before complete combustion can occur.

In addition outdoor wood-fired boilers smoke heavily due to their cyclical operating pattern. When the temperature of the water within the boiler falls below a set point, its combustion air damper opens and/or a small fan forces combustion air into the firebox. Once the water is heated back to the upper set point, the fan is turned off and/or the combustion air damper closes. During the off cycles the fire smolders and much of the smoke condenses as creosote on the cold steel internal surfaces. When the thermostat again calls for heat and incoming combustion air rekindles the fire, the heat ignites the creosote clinging to the boiler walls. This leads to an increase in emissions that accompanies the poor combustion in the firebox.

Outdoor wood-fired boilers are also sometimes not sized appropriately for the house that they are intended to heat. For example, an oversized boiler will tend to run in the smoldering phase longer than in the full out burn phase, thereby producing more smoke.

It has been suggested that excessive production of emissions by outdoor wood-fired boilers is associated improper installation of the boiler or the use of fuels not designed to be combusted in the boiler (personal communication with Peter Guldberg, Tech Environmental). Additionally, Guldberg, 2007 suggests that emissions from outdoor wood-fired boilers are comparable to other wood-fired combustion devices in terms of lbs/MMBTU heat generated. In any case, Guldberg, 2007 indicates that outdoor wood-fired boiler manufacturers have worked with EPA to develop a voluntary Outdoor Wood-fired Heater Program with a Phase I emission target of 0.6 lb/MMBTU. According to Guldberg, 2007 manufacturers will offer the outdoor wood-fired heaters qualified to achieve the Phase I standard later in 2007.

NESCAUM's Model Rule

On January 29, 2007, NESCAUM made available its "Outdoor Hydronic Heater Model Regulation." The model rule is designed to serve as a template to assist State and local agencies in adopting requirements that will reduce air pollution from outdoor wood-fired boilers. The model rule was developed in cooperation with a number of States and EPA. The model rule has provisions for:

- Critical definitions,
- Emission standards,
- Test method procedures,
- Certification process, and
- Labeling requirements.

The model rule contains a single method for regulating new units with respect to the critical elements and contemplates that States may propose alternative approaches for other provisions. It also provides alternatives for states to consider for regulating previously installed units (NESCAUM 2007).

NESCAUM's model rule sets standards for particulate matter (PM) emissions by phases for residential and commercial boilers. The PM standards for both boiler types are identical. Phase I calls for a PM emission limit or 0.44 pounds per million BTU heat input. This standard would have to be met by March 31, 2008. Phase II calls for a PM emission standard of 0.32 lb/MMBTU which is to be met by March 31, 2010.

Vermont's Rule on Outdoor Wood-fired Boilers

On April 12, 2007 Vermont filed a regulation on outdoor wood-fired boilers with the Secretary of State and the Legislative Committee on Administrative Rules. The rule legally went into effect on April 27, 2007, and adopts NESCAUM's model rule Phase 1 PM emission standard of 0.44 lb/MMBTU. As of March 31, 2008, outdoor wood-fired boilers not meeting the standard of 0.44 lb/MMBTU cannot be sold in Vermont. Additional information on Vermont's final rule on outdoor wood-fired boilers can be found on the following web site: http://www.vtwoodsmoke.org. (Etter, personal communication)

This section of this document addresses the four factor analysis which includes the following elements: cost of compliance, time necessary for compliance, energy and non-air impacts, and remaining useful life of the source.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR OUTDOOR WOOD-FIRED BOILERS

Cost of Compliance

Outdoor wood-fired boilers are priced according to their size (heat output). For example, Northwest Manufacturing sells a line of outdoor wood-fired boilers that ranges in price from $4,295 for a boiler that will heat a 2,000 square foot house to $12,995 for a boiler that can heat up to 20,000 square feet. Similarly, Hud-Son Forest Equipment has a line of outdoor wood-fired boilers that range in price from $6,095 for boiler that can heat a 2,000 square foot house to $7,795 for a boiler that can heat up to 10,000 square feet.

There are currently only a few outdoor wood-fired boiler manufacturers whose products would meet the 2008 NESCAUM phase I standard of 0.44 lb/MMBTU. NESCAUM estimates that there are "several units currently on the market that can meet this standard." In addition, NESCAUM estimates that more stringent air standards that it proposed should come into compliance in 2010 would currently only be met by one unit. Consequently, manufacturers of outdoor wood-fired boilers would have to invest money into research and development in order to manufacture boilers that would meet NESCAUM's model standards. MACTEC contacted an outdoor wood-fired boiler manufacturer to determine cost increases due to the NESCAUM rule. The boiler manufacturer was not able to provide estimated cost increases necessary to manufacture boilers meeting the NESCAUM model rule standards (personal communication with Central Boiler, Inc.).

MACTEC also investigated the costs of replacing the outdoor wood-fired boilers with heating oil-fired furnaces and boilers. We determined that the capital cost of oil-fired water boilers ranged from $2,800 - $3,825. Similarly, the capital cost of oil-fired furnaces range from $1,560 -

$1,800 (Alpine Home Air 2007). Therefore, oil-fired boilers and furnaces can be substantially less expensive than outdoor wood-fired boilers.

In a previous section, information was presented on the average amount of distillate fuel oil used on an annual basis by households in the Northeast. It was estimated that households use approximately 865 gal/yr of fuel oil (STAPPA-ALAPCO 2006). Therefore, the annual average heating cost using fuel would currently be approximately $2,100 (assuming a fuel oil price of $2.40/gal). The University of Wisconsin Solid and Hazardous Waste Education Center (2007) estimates that it would take only 4 full cords of oak firewood to heat a house per year. At approximately $200/cord (Boston.com 2004), this equates to an annual fuel cost of $800/year. Consequently, the annual cost for firewood is $1,300 less than the cost of distillate fuel oil. Additionally, many operators of outdoor wood boilers have access to a free supply of firewood for the boiler, thus the only fuel cost to these operators is the time, effort, and expense associated with gathering the wood and cutting it for use in the outdoor wood-fired boiler.

Assuming the average household use of 865 gal/yr of fuel oil, and a fuel oil heating value of 140 MMBTU per thousand gallons, the annual heat input required is 121.1 MMBTU. The emission factors for residential fuel oil combustion, natural gas combustion, and wood combustion in outdoor wood-fired boilers are 0.003, 0.002, and 1.5 to 3.1 pounds of PM per MMBTU heat input respectively. Using the annual heat input requirement of 121.1 MMBTU, the annual emissions from an oil-fired furnace would be 0.4 pounds, the emissions from a natural gas-fired furnace would be 0.2 pounds, and the emissions from the outdoor wood-fired boiler would be from 180 to 380 pounds. The cost of replacing an outdoor wood-fired boiler with an oil-fired furnace or boiler is estimated to be from $1,560 to $3,825 (Alpine Home Air 2007). If the capital cost of the oil-fired furnace or boiler is spread over ten years, the annualized capital cost is between $156 and $383. Additionally, the cost of fuel oil is estimated to be from $0 to $2,100 more than the outdoor wood-fired boiler fuel costs depending on whether the operator has access to a free wood supply, or must purchase the wood by the cord. Based on these estimates, the PM cost effectiveness of replacing an outdoor wood-fired boiler with an oil-fired furnace or boiler would be from $1,700 to $13,000 per ton of PM reduced. The costs for replacement of outdoor wood-fired boilers with natural gas-fired furnaces or boilers have not been quantified.

Time Necessary for Compliance

Outdoor wood-fired boilers have been in operation for approximately the last 15 years (personal communication with P. Etter from Vermont Air Pollution Control). Consequently, the average age of outdoor wood-fired boilers is not known. On at least one occasion, a boiler vendor opted to go out of business rather than honor 5-year warranties (personal communication with J. Gulland from OutdoorHeat.org). If States pass a rule similar to NESCAUM's and existing boilers are grandfathered, only new boilers would be required to meet the more stringent standards. In the section on residential heating, it was estimated that the average useful life of a residential boiler is between 18-25 years. Well manufactured outdoor wood-fired boilers may have similar useful lives. Therefore, new boilers meeting more stringent PM emissions standards would be phased in slowly as older boilers are replaced.

Replacement of wood-fired boilers with oil-fired furnaces or boilers could occur on a very quick schedule. The number of residential boiler/furnace manufacturers in the United States is indicative of the fact that there is an ample supply of manufacturers. Although it is possible for outdoor wood-fired boilers to be replaced quickly, realistically, most of these units have been installed within the past 15 years. Since they are designed to last for approximately 20 years, operators of the outdoor wood-fired boilers would likely be reluctant to replace them immediately.

Energy and Non-Air Impacts

Wood is a renewable resource that is plentiful in the United States Northeast. The increased use of outdoor wood-fired boilers would lead to an increase in the amount of firewood that is combusted in the US Northeast on an annual basis. Alternatively, tighter rules regarding the PM emissions from outdoor wood-fired boilers may lead to a decrease in their use, which would make more firewood available for use in wood stoves and fire places. A move away from wood-fired boilers would increase the demand on heating fuels such as heating oil, propane, and potentially coal or natural gas.

The increased use of outdoor wood-fired boilers may have a variety of non-air impacts on the environment, especially on forest and water resources. The potential impacts are outlined below.

Nuisance Smoke: Outdoor wood-fired boilers typically have very short stacks, and are prone to smoke. The short stacks oftentimes prevent proper mixing of the smoke and soot with the surrounding air, thereby creating nuisance smoke problems for surrounding houses or communities (Michigan DEQ 2007).

Water: Increased logging to satisfy the demand for firewood may increase runoff of silts and sediments into adjacent creeks and rivers. This increased sediment load in rivers can affect aquatic ecosystems that are integral to rivers and streams.

Soils: Increased logging may impact soils in many ways. For example, heavy machinery used to fell and process trees may lead to rutting and compaction of the soil, which in turn leads to higher erosion and/or altered vegetative regrowth.

Wildlife: Increased logging may put pressure on existing wildlife populations in the US Northeast by altering their critical habitat.

Threatened and Endangered Species: Increased logging in Northeast may impact threatened and endangered species through habitat destruction or alteration.

Remaining Useful Life of the Source

The useful life of outdoor wood-fired boilers is approximately 20 years, which is also very close to the useful life of other residential boilers (Etter, personal communication). In addition, Mr. Etter indicated that outdoor wood-fired boilers have only been around for approximately 15 years, therefore, most of the boilers that have been put into service are likely to remain there for at least the next five years.

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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 COURSE OF ACTION WITHIN MANE-VU TOWARD ASSURING REASONABLE PROGRESS

The federal Clean Air Act and 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, any additional air pollutant emission reduction measures necessary to meet the 2018 reasonable progress goal for regional haze should be implemented 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 will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. This course of action includes pursuing the adoption and implementation of the following "emission management" strategies, as appropriate and necessary:

- timely implementation of 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 (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

- 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.

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 and cost-effective 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

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:
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		
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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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
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:
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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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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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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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BASELINE AND NATURAL BACKGROUND VISIBILITY CONDITIONS

CONSIDERATIONS AND PROPOSED APPROACH TO THE CALCULATION OF BASELINE AND NATURAL BACKGROUND VISIBILITY CONDITIONS AT MANE-VU CLASS I AREAS

Prepared by NESCAUM

December, 2006

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BASELINE AND NATURAL BACKGROUND VISIBILITY CONDITIONS

Considerations and Proposed Approach to the Calculation of Baseline and Natural Background Visibility Conditions at MANE-VU Class I Areas

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1. INTRODUCTION

The long-term visibility conditions that would exist in absence of human-caused impairment are referred to as *natural background* visibility conditions. Accurate assessment of these conditions is important due to their role in determining the uniform rate of progress that states must consider when setting reasonable progress goals for each mandatory Federal Class I area subject to the Regional Haze Rule. Baseline visibility conditions – based on monitored visibility during the five year baseline period (2000-2004) – and estimated natural background visibility conditions will determine the uniform rate of progress states will consider when setting reasonable progress goals for any Class I site.

In September 2001, the U.S. Environmental Protection Agency (EPA) issued draft methodological guidelines for the calculation of natural background and baseline visibility conditions as well as methods for tracking progress relative to the derived uniform rate of progress. EPA subsequently finalized this draft guidance in September 2003. The final guidance recommends a default method and allows for certain refinements that states may wish to pursue in order to make these estimates more representative of a specific Class I area if it is poorly represented by the default method.

In the spring of 2006, the IMPROVE Steering Committee adopted an alternative formulation of the reconstructed extinction equation to address certain aspects of the default calculation method. These aspects were well understood from a scientific perspective and were felt to improve the performance of the equation at reproducing observed visibility at Class I sites. This alternative formulation of the reconstructed extinction equation was not adopted as a replacement to the default method, but as an alternative to the default method for states and RPOs to consider as they proceed with the regional haze planning process. It seems likely that most, if not all, RPOs are considering this alternative formulation as the means by which they will calculate baseline conditions, natural background conditions, and track progress toward the national visibility goals under the Regional Haze Rule.

In this report, MANE-VU reviews the default and alternative approaches to the calculation of baseline and natural background conditions and presents a discussion of the principle differences between the methods. In addition, the default and alternative methods are applied to each Class I area in or near the MANE-VU region in order to establish *differences* in baseline conditions, natural background conditions, and 2018 uniform progress goals under each approach.

The prior MANE-VU position on natural background conditions was issued in June, 2004 and stated that, “Refinements to other aspects of the default method (e.g., refinements to the assumed distribution or treatment of Rayleigh extinction, inclusion of sea salt, and improved assumptions about the chemical composition of the organic fraction) may be warranted prior to submissions of SIPs depending on the degree to which scientific consensus is formed around a specific approach…” Based upon the subsequent reviews conducted by the IMPROVE Steering Committee, as well as internal Technical Steering Committee deliberations, MANE-VU is now ready to adopt the alternative reconstructed extinction algorithm for the reasons described in this report.

2. THE DEFAULT METHOD

The default method is explained in detail in *Estimating Natural Background Visibility Conditions* (U.S.EPA, 2003a) and *Guidance for Tracking Progress under the Regional Haze Rule* (U.S. EPA, 2003b). Summary information is provided here but the reader should consult the original guidance documents for any question on how to apply this method.

Estimates of natural visibility impairment due to fine and coarse particles were derived using the 1990 National Acid Precipitation Assessment Program reported average ambient concentrations of naturally present particles (Trijonis, 1990). Separate concentration values were given for the eastern and western United States; no finer spatial resolution is available. Average natural background light extinction due to particles was then calculated using the IMPROVE methodology and site specific ANNUAL f(RH) values. Worst visibility levels are derived using the work of Ames and Malm (2001), who estimated the standard deviation of visibility in deciviews in the eastern U.S. as 3 dv. By assuming a roughly normal distribution of data, the default method adds (subtracts) 1.28*(3 dv) to the average estimated natural background to calculate the 90th (10th) percentile level, which is taken by EPA to be representative of the mean of the 20 percent worst (best) conditions.

In the East, the default method for calculating best and worst natural background visibility conditions (in dv) for any area in the eastern U.S. uses the following formulae:

$$P90 = HI + 1.28\ sd$$

$$P10 = HI - 1.28\ sd$$

P90 and P10 represent the 90th and 10th percentile, respectively, the Haze Index (HI) represents annual average visibility in units of deciview, and sd is the standard deviation of daily average visibility values throughout a year, defined by the guidance as 3.0 for the eastern U.S. The Haze Index is calculated as shown:

$$HI = 10 \ln (bext/10)$$

The atmospheric extinction, bext, is given by the familiar IMPROVE equation (IMPROVE, 2000) in inverse megameters:

$$bext = (3)f(RH)[sulfate] + (3)f(RH)[nitrate] + (4)[OMC] + (10)[LAC] + (1)[SOIL] + (0.6)[CM] + 10$$

Table 2-1 below provides the default values to be applied at all eastern U.S. Class I areas. The result of using these default values in the above equation with an assumed annual average f(RH) value of 3.17 in the northeastern U.S. (the average of 11 northeastern U.S. sites) is approximately 3.6 dv on the 20 percent best days and 11.3 dv on the 20 percent worst days.

The methods for calculating baseline conditions on the 20 percent best or worst days start by repeating the calculation of the Haze Index (HI) as shown above with the individual species mass concentrations replaced by the actual monitored values for each day during the baseline period. These values should be sorted from highest to lowest for each year in the baseline period. Averages (in dv) for each year can be calculated for HI values associated with the 20 percent most impaired and 20 percent least impaired days. The average HI values for the 20 percent most impaired and 20 percent least impaired days in each year should then be averaged for the five consecutive years 2000-2004 to define baseline conditions. One important distinction between the natural conditions and baseline HI calculations is that the f(RH) values shown in Table 2-2 for natural conditions estimates are annual averages. EPA has also estimated site-specific

Table 2-1. Default parameters used in calculating natural background visibility for sites in the eastern U.S.

Parameter	**Value**	**Fractional Uncertainty**	**Reference/Comments**
[SULFATE]	0.23 µg/m^3	200%	Trijonis, 1990
[NITRATE]	0.10 µg/m^3	200%	Trijonis, 1990
[OC]	1.0 µg/m^3	200%	Trijonis, 1990
[LAC]	0.02 µg/m^3	250%	Trijonis, 1990
[SOIL]	0.50 µg/m^3	200%	Trijonis, 1990
[CM]	3.0 µg/m^3	200%	Trijonis, 1990
f(RH)	~3.2	15%	Varies by site (see Table 2-2)
Organic multiplier	1.4	50%	[OMC]=1.4*[OC]
$\sigma_{S/N}$	3.0 m^2/g	33%	Hegg, 1997; IMPROVE, 2000; Malm, 2000
σ_{OC}	4.0 m^2/g	30%	Hegg 1997; Trijonis 1990
σ_{EC}	10.0 m^2/g	40%	Malm, 1996
σ_{soil}	1.0 m^2/g	25%	Trijonis, 1990
σ_{coarse}	0.6 m^2/g	33%	IMPROVE, 2000
Rayleigh	10 Mm^{-1}	20 %	Varies with altitude/season
sd (standard deviation of daily visibility)	3.0 dv	16%	Ames and Malm, 2001
10th, 90th percentile adjustment	1.28	15%	Regulation calls for mean of top twenty percent, not 90th percentile
Parameters used in potential refinements			
[NaCl]	~0.5	50%	Varies by site, IMPROVE
σ_{NaCl}	2.5 m^2/s	16%	Haywood, 1999
f(RH)$_{NaCl}$	~3.2	33%	Assumed same as S, N

Note: The mass estimates presented above are based on estimates of fine particulate concentrations that would exist in absence of any manmade pollution (including Mexican and Canadian emissions) consistent with planning requirements of the Regional Haze Rule. MANE-VU accepts this as an appropriate planning goal and intends to consider the contribution of international transport in deciding what controls are "reasonable" under the regional haze program.

climatological mean monthly average values of f(RH) that are provided in an appendix to its guidance (EPA, 2003b) and used for the individual HI calculations for baseline conditions.

2.1. Application of the Default Methods

The Class I areas in the MANE-VU region that are subject to the requirements of the Regional Haze Rule are: 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. In addition to these Class I areas, we consider several nearby Class I areas where MANE-VU states may be contributing to visibility impairment. These Class I areas include: Dolly Sods Wilderness and the Otter Creek Wilderness in West Virginia as well as Shenandoah National Park and the James River Face Wilderness in Virginia. MANE-VU understands that it is the responsibility of the appropriate VISTAS states to establish estimates of natural visibility conditions and reasonable progress goals for these areas. It is anticipated, however, that subsequent consultations will occur with those MANE-VU states that may be affecting visibility in these areas. MANE-VU has therefore calculated estimates of natural background visibility conditions at the nearby sites using MANE-VU approved methods in order to facilitate future consultations.

The only factor in the default method that varies by site is the climatological annual mean relative humidity adjustment factor. Table 2-2 lists this value for the Class I sites of interest and the resulting best 20 percent and worst 20 percent estimates of natural visibility conditions. The variation among sites using the default method is purely a function of differences in climatological annual mean relative humidity, with southern and coastal sites being more humid than inland or elevated sites.

Table 2-2. Site-specific relative humidity adjustment factors, best and worst (default) estimates of natural background visibility conditions.

MANE-VU Mandatory Federal Class I Area	f(RH)	Best Visibility (dv)	Worst Visibility (dv)
Maine			
Acadia National Park	3.34	3.77	11.45
Moosehorn Wilderness	3.15	3.68	11.36
Roosevelt Campobello International Park, New Brunswick	3.16	3.68	11.37
New Hampshire			
Great Gulf Wilderness	3.01	3.63	11.30
Presidential Range – Dry River Wilderness	3.02	3.65	11.30
New Jersey			
Brigantine Wilderness	2.97	3.60	11.28
Vermont			
Lye Brook Wilderness	2.91	3.57	11.25
Nearby Mandatory Federal Class I Area			
Virginia			
James River Face Wilderness	2.93	3.56	11.26
Shenandoah National Park	2.95	3.57	11.27
West Virginia			
Dolly Sods Wilderness	3.06	3.64	11.32
Otter Creek Wilderness	3.06	3.65	11.32

Table 2-3. Site-specific best and worst (default) estimates of baseline visibility conditions (2000-2004).

MANE-VU Mandatory Federal Class I Area	Best Visibility (dv)	Worst Visibility (dv)
Maine		
Acadia National Park	8.06	22.34
Moosehorn Wilderness	8.48	21.18
Roosevelt Campobello International Park, New Brunswick	8.48	21.18
New Hampshire		
Great Gulf Wilderness	7.50	22.25
Presidential Range – Dry River Wilderness	7.50	22.25
New Jersey		
Brigantine Wilderness	13.72	27.60
Vermont		
Lye Brook Wilderness	6.20	23.70
Nearby Mandatory Federal Class I Area		
Virginia		
James River Face Wilderness	14.35	27.72
Shenandoah National Park	11.34	27.88
West Virginia		
Dolly Sods Wilderness	12.70	27.64
Otter Creek Wilderness	12.70	27.64

3. THE ALTERNATIVE METHOD

According to EPA guidance, “[T]he default approach to estimating natural visibility conditions presented in this document is adequate for the development of progress goals for the first implementation period under the regional haze rule” (U.S. EPA, 2003a). However, the guidance does leave the door open for individual states or RPOs to adopt their own methods for calculating natural background (or baseline conditions) if they can demonstrate that the change from the default represents a significant refinement that better characterizes natural visibility (or baseline) conditions at a specific Class I site.

In response to a number of concerns raised with respect to the use of the default methods for Regional Haze Rule compliance (Lowenthal and Kumar, 2003; Ryan et al., 2005), the IMPROVE Steering Committee established a subcommittee to review the default approach and recommend refinements to address criticisms and improve the performance for tracking progress under the Haze Rule. The details presented below come from that subcommittee's summary report and a review of potential refinements by Hand and Malm (2005).

The recommended revised algorithm is shown in the equation below with revised terms in bold font. The total sulfate, nitrate, and organic carbon compound concentrations are each split into two fractions, representing small and large size distributions of those components. Although not explicitly shown in the equation, the organic mass concentration used in this new algorithm is 1.8 times the organic carbon mass concentration, which is changed from 1.4 times the carbon mass concentration as used for input in the current IMPROVE algorithm. New terms have been added for sea salt (important for coastal locations) and for absorption by NO_2 (only used where NO_2 data are available). Site-specific Rayleigh scattering is calculated for the elevation and annual average temperature of each of the IMPROVE monitoring sites.

Bext ≈ 2.2 x f_S(RH) x [Small Sulfate] + 4.8 x f_L(RH) x [Large Sulfate] +
2.4 x f_S(RH) x [Small Nitrate] + 5.1 x f_L(RH) x [Large Nitrate] +
2.8 x [Small Organic Mass] + 6.1 x [Large Organic Mass] +
10 x [Elemental Carbon Mass] + 1 x [Fine Soil Mass] +
1.7 x f_{SS}(RH) x [Sea Salt Mass] + 0.6 x [Coarse Mass] +
Rayleigh Scattering (site specific) + 0.33 x [NO_2 (ppb)]

The apportionment of the total concentration of sulfate compounds into the concentrations of the small and large size fractions is accomplished using the following equations.

$$[Large\ \ Sulfate] = \frac{[Total\ Sulfate]}{20\mu g/m^3} \times [Total\ Sulfate],\quad for\ [Total\ Sulfate] < 20\mu g/m^3$$

$$[Large\ \ Sultate\ ] = [Total\ \ \ Sulfate\ \ ]\quad for\ \ [Total\ \ \ Sulfate\ ] \geq 20\ \mu g\ /\ m^3$$

$$[Small\ Sulfate] = [Total\ Sulfate] - [Large\ \ Sulfate]$$

The same equations are used to apportion total nitrate and total organic mass concentrations into the small and large size fractions.

Sea salt is calculated as 1.8 x [*Chloride*], or 1.8 x [*Chlorine*] if the chloride measurement is below detection limits, missing, or invalid. The algorithm uses three water growth adjustment terms as shown in Figure 3-1 and Table 3-1. They are for use with the small size distribution and the large size distribution sulfate and nitrate compounds and for sea salt ($f_S(RH)$, $f_L(RH)$, and $f_{SS}(RH)$, respectively).

Figure 3-1. Water growth curves for small and large size distribution sulfate and nitrate, sea salt, and the original IMPROVE algorithm sulfate and nitrate.

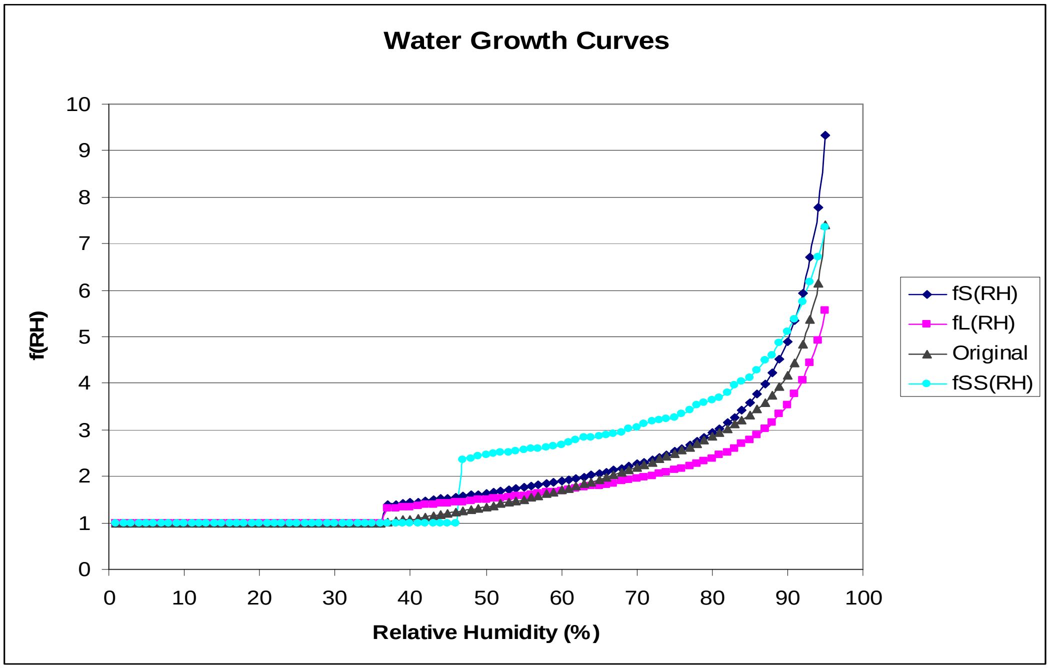

Table 3-1. f(RH) for small and large size distribution sulfate and nitrate, and sea salt.

RH (%)	f_S(RH)	f_L(RH)	f_{SS}(RH)	RH (%)	f_S(RH)	f_L(RH)	f_{SS}(RH)	RH (%)	f_S(RH)	f_L(RH)	f_{SS}(RH)
0 to 36	1.00	1.00	1.00	**56**	1.78	1.61	2.58	**76**	2.60	2.18	3.35
37	1.38	1.31	1.00	**57**	1.81	1.63	2.59	**77**	2.67	2.22	3.42
38	1.40	1.32	1.00	**58**	1.83	1.65	2.62	**78**	2.75	2.27	3.52
39	1.42	1.34	1.00	**59**	1.86	1.67	2.66	**79**	2.84	2.33	3.57
40	1.44	1.35	1.00	**60**	1.89	1.69	2.69	**80**	2.93	2.39	3.63
41	1.46	1.36	1.00	**61**	1.92	1.71	2.73	**81**	3.03	2.45	3.69
42	1.48	1.38	1.00	**62**	1.95	1.73	2.78	**82**	3.15	2.52	3.81
43	1.49	1.39	1.00	**63**	1.99	1.75	2.83	**83**	3.27	2.60	3.95
44	1.51	1.41	1.00	**64**	2.02	1.78	2.83	**84**	3.42	2.69	4.04
45	1.53	1.42	1.00	**65**	2.06	1.80	2.86	**85**	3.58	2.79	4.11
46	1.55	1.44	1.00	**66**	2.09	1.83	2.89	**86**	3.76	2.90	4.28
47	1.57	1.45	2.36	**67**	2.13	1.86	2.91	**87**	3.98	3.02	4.49
48	1.59	1.47	2.38	**68**	2.17	1.89	2.95	**88**	4.23	3.16	4.61
49	1.62	1.49	2.42	**69**	2.22	1.92	3.01	**89**	4.53	3.33	4.86
50	1.64	1.50	2.45	**70**	2.26	1.95	3.05	**90**	4.90	3.53	5.12
51	1.66	1.52	2.48	**71**	2.31	1.98	3.13	**91**	5.35	3.77	5.38
52	1.68	1.54	2.50	**72**	2.36	2.01	3.17	**92**	5.93	4.06	5.75
53	1.71	1.55	2.51	**73**	2.41	2.05	3.21	**93**	6.71	4.43	6.17
54	1.73	1.57	2.53	**74**	2.47	2.09	3.25	**94**	7.78	4.92	6.72
55	1.76	1.59	2.56	**75**	2.54	2.13	3.27	**95**	9.34	5.57	7.35

The proposed new algorithm for estimating haze reduces the biases compared to measurements at the high and low extremes. This is most apparent for the hazier eastern sites. The composition of days selected as best and worst by the current and the new algorithm are very similar, and similar to days selected by measurements. Most of the reduction of bias associated with the new algorithm is attributed to the use of the split component extinction efficiency method for sulfate, nitrate, and organic components that permitted variable extinction efficiency depending on the component mass concentration. Although not subject to explicit performance testing, the proposed new algorithm also contains specific changes from the current algorithm that reflect a better understanding of the atmosphere as reflected in the more recent scientific literature (e.g., change to 1.8 from 1.4 for organic compound mass to carbon mass ratio) and a more complete accounting for contributors to haze (e.g., sea salt and NO_2 terms), and use of site specific Rayleigh scattering terms to reduce elevation-related bias.

Unlike the default approach, which directly uses the Trijonis natural species concentration estimates to calculate natural haze levels, the Alternative Approach uses the baseline data (current species concentrations) with a multiplier applied to each species measurement in order to give the Trijonis estimate for that species. The ratio of the Trijonis estimates for each species divided by the annual mean values for the species is used to transform the entire data set to what is then assumed to be the natural species concentration levels for that site and year. This process is applied to each of the complete years of data (as defined by the EPA *tracking progress* guidance) in the baseline period (2000 through 2004). Sites with three complete years of data are treated as having sufficient data for this assessment. If any of the current annual means for any species is less than the Trijonis estimate for that species, the unadjusted species data are used. Trijonis estimates did not include sea salt, which is only significant at a few coastal sites. Estimates of current sea salt concentrations determined from Cl^- ion data (described as part of the new IMPROVE algorithm) are taken to be natural contributors to haze.

3.1. Application of the Alternative Method

Here we present a comparison of the background and natural visibility conditions calculated using the default and the alternative methods (see Table 3-2 and Table 3-3). Corresponding visibility improvement targets for 2018 using each approach are also presented (see Table 3-3). Results suggest that the alternative approach leads to very similar uniform rates of progress in New England with slightly greater visibility improvement required in the Mid-Atlantic region relative to the default approach.

Table 3-2. Comparison of default and alternative approaches for estimating the 20 percent worst natural background visibility conditions at MANE-VU and nearby sites (2000-2004).

MANE-VU Mandatory Federal Class I Area	Default Baseline dv	Alternative Baseline dv	Default Natural dv	Alternative Natural dv
Maine				
Acadia National Park	22.34	22.89	11.45	12.43
Moosehorn Wilderness	21.18	21.72	11.36	12.01
Roosevelt Campobello International Park, New Brunswick	21.18	21.72	11.37	12.01
New Hampshire				
Great Gulf Wilderness	22.25	22.82	11.30	11.99
Presidential Range – Dry River Wilderness	22.25	22.82	11.30	11.99
New Jersey				
Brigantine Wilderness	27.60	29.01	11.28	12.24
Vermont				
Lye Brook Wilderness	23.70	24.45	11.25	11.73
Nearby Mandatory Federal Class I Areas				
Virginia				
James River Face Wilderness	27.72	29.12	11.26	11.13
Shenandoah National Park	27.88	29.31	11.27	11.35
West Virginia				
Dolly Sods Wilderness	27.64	29.04	11.32	10.39
Otter Creek Wilderness	27.64	29.04	11.32	10.39

Table 3-3. Estimated uniform rates of progress (ROP) (to be considered for worst 20 percent days) and Best Day Baseline Conditions (not to be degraded on best 20 percent days) for first implementation period.

MANE-VU Mandatory Federal Class I Area	**Default ROP** Worst day (dv/14 yrs)	**Alternative ROP** Worst day (dv/14 yrs)	**Default Baseline Visibility** Best Day (dv)	**Alternative Baseline Visibility** Best Day (dv)
Maine				
Acadia National Park	2.54	2.44	8.06	8.77
Moosehorn Wilderness	2.29	2.27	8.48	9.15
Roosevelt Campobello International Park, New Brunswick	2.29	2.27	8.48	9.15
New Hampshire				
Great Gulf Wilderness[†]	2.56	2.53	7.50	7.66
Presidential Range – Dry River Wilderness[†]	2.56	2.53	7.50	7.66
New Jersey				
Brigantine Wilderness[‡]	3.81	3.91	13.72	14.33
Vermont				
Lye Brook Wilderness	2.91	2.97	6.20	6.36
Nearby Mandatory Federal Class I Area				
Virginia				
James River Face Wilderness[Π]	3.84	4.20	14.35	14.21
Shenandoah National Park[‡]	3.88	4.19	11.34	10.93
West Virginia				
Dolly Sods Wilderness	3.81	4.35	12.70	12.28
Otter Creek Wilderness	3.81	4.35	12.70	12.28

Note: The values are presented for the default and alternative approaches at MANE-VU and nearby sites (2000-2004).

The default estimates provide a sound, nationally consistent framework on which to base the regulatory structure of the Haze Rule that is justified by the current state of scientific understanding of these issues. However, an alternative approach for the calculation of reconstructed extinction under the Regional Haze Rule has been developed that provides all of the same advantages. EPA recommendations on potential refinements to the default approach (Pitchford, personal communication, 2004) suggest that, if used, any refinements should be broadly accepted by the scientific community, substantial, practical to implement, and not create arbitrary inconsistencies. The alternative approach endorsed by the IMPROVE Steering Committee for baseline and natural background conditions meet these requirements.

4. RECOMMENDATIONS

This document reviews EPA guidelines and an IMPROVE Steering Committee-endorsed alternative for calculating baseline and natural background visibility conditions under the Regional Haze Rule. It also explores how adoption of the alternative approach would affect calculated rates of progress and other regulatory drivers under the Haze Rule.

The alternative approach attempts to incorporate better science for several components of the equation to calculate reconstructed extinction that reflects the latest scientific research. MANE-VU recognizes the time and effort that has been invested in the development of this alternative. We also recognize the high likelihood that other RPOs will adopt and use the alternative approach and consider it desirable to use a similar approach to other RPOs with which MANE-VU will consult on visibility goals. Given the large uncertainties that remain in our ability to estimate the concentrations of organic carbon and other species that would be present in the absence of anthropogenic influences, we are not certain that the alternative approach significantly improves the overall accuracy of the estimated natural background conditions, but it certainly does not diminish the accuracy and is likely to improve our estimates of baseline conditions.

Finally, MANE-VU has considered the fact that the uniform rate of progress that results from these calculations is a relatively arbitrary baseline against which progress is measured. This Haze Rule requires states to consider this uniform rate, but control decisions are to be based on a four-factor analysis that is independent of the uniform rate of progress. The relatively small differences in the uniform rate that are introduced as a result of using the alternative approach further diminish the significance of this decision. Based on all of the considerations above, MANE-VU recommends adoption of the alternative approach for use in 2008 MANE-VU SIP submittals, active participation in further research efforts on this topic, and future reconsideration of natural background visibility conditions as evolving scientific understanding warrants.

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