Appendix N - MANE-VU Basis for Reasonable Controls

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

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

Focus on SO_2

MANE-VU conducted a Contribution Assessment and developed a conceptual model that indicated that the dominant contributor to visibility impairment at all sites during all seasons in the base year was particulate sulfate formed from emissions of SO_2. (See the NESCAUM report entitled Contributions to Regional Haze in the Northeast and Mid-Atlantic United States, Appendix A). The report concludes that sulfates alone account for from one-half to two-thirds of total fine particle mass on the 20 percent haziest days at MANE-VU Class I sites. In view of the dominant role of sulfate in visibility impairment in Northeast and Mid-Atlantic class I areas, the report states that, "[T]hese findings suggest that an effective emissions management approach would rely heavily on broad-based regional SO2 control efforts in the eastern United States." While other pollutants, including organic carbon, will need to be addressed in order to achieve the national visibility goals, MANE-VU's Contribution Assessment suggested that an early emphasis on SO_2 will yield the greatest near-term benefit. Therefore, it is reasonable that the additional measures considered in setting the reasonable progress goals described in this document required reductions of SO_2 emissions.

Contributing Sources

The MANE-VU Contributions Assessment indicates that emissions from within MANE-VU in 2002 were responsible for about 25 to 30 percent of the sulfate at MANE-VU Class I areas. Sources in the Midwest and Southeast regions were responsible for about 15 to 25 percent each. Point sources dominated the inventory of SO_2 emissions. Therefore, the MANE-VU strategies discussed in Section 9.4 and 9.5, above, include additional measures to control sources of SO_2 both within the MANE-VU region and in other states that were determined to contribute to regional haze at MANE-VU Class I areas.

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

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

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

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

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

Summary of Results from the Four Factor Analysis

Source Category	Primary Regional Haze Pollutant	Potential Control Measure(s)	Average Cost (in 2006 dollars) per Ton of Pollutant Reduction	Compliance Timeframe	Energy and Non-Air Quality Environmental Impacts	Remaining Useful Life
Electric Generating Units	SO_2	Switch to a low sulfur coal (generally <1% sulfur), switch to natural gas (virtually 0% sulfur), coal cleaning, Flue Gas Desulfurization (FGD)-Wet, Flue Gas Desulfurization (FGD)-Spray Dry, Flue Gas Desulfurization (FGD) - Dry.	MANE-VU application of IPM®* v.2.1.9 predicts $775 to $1,690. MACTEC reports $170 to $5,700 based on available literature depending on control method and size of source	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, reduction in electricity production capacity, wastewater issues	50 years or more
Industrial, Commercial, Institutional Boilers	SO_2	Switch to a low sulfur coal (generally <1% sulfur), switch to natural gas (virtually 0% sulfur), switch to a lower sulfur oil, coal cleaning, combustion control, Flue Gas Desulfurization (FGD)-Wet, Flue Gas Desulfurization (FGD)-Spray Dry, Flue Gas Desulfurization (FGD) - Dry.	MACTEC reports $130 to $11,000 based on available literature. Depends on size of plant and control method.	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, control device energy requirements, wastewater issues	10-30 years

Source Category	Primary Regional Haze Pollutant	Potential Control Measure(s)	Average Cost (in 2006 dollars) per Ton of Pollutant Reduction	Compliance Timeframe	Energy and Non-Air Quality Environmental Impacts	Remaining Useful Life
Cement and Lime Kilns	SO_2	Fuel switching, Dry Flue Gas Desulfurization-Spray Dryer Absorption (FGD), Wet Flue Gas Desulfurization (FGD), Advanced Flue Gas Desulfurization (FGD).	MACTEC reports $1,900 to $73,000 based on available literature. Depends on size of plant and control method.	2-3 years following SIP submittal	Control device energy requirements, wastewater issues	10-30 years
Heating Oil	SO_2	Lower the sulfur content in the fuel. Depends on the state.	MACTEC reports $550 to $750 based on available literature. There is a high uncertainty associated with this cost estimate.	Currently feasible. Capacity issues may influence timeframe for implementation of new fuel standards	Increases in furnace/boiler efficiency, Decreased furnace/boiler maintenance requirements	18-25 years
Residential Wood Combustion	PM	State implementation of NSPS, ban on resale of uncertified devices, installer training certification or inspection program, pellet stoves, EPA Phase II certified RWC devices, retrofit requirement, accelerated changeover requirement, accelerated changeover inducement.	MACTEC reports $0 to $10,000 based on available literature	Several years - dependent on mechanism for emission reduction	Reduce greenhouse gas emissions, increase efficiency of combustion device	10-15 years

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

I. Best Available Retrofit Technology is Reasonable

BART controls are part of the strategy for improving visibility at MANE-VU Class I areas. MANE-VU prepared reports to provide states with information about available controls and the cost and other factors associated with those controls. The reasonable progress goals set in this SIP assume that states whose emissions affect MANE-VU Class I areas will make reasonable determinations concerning BART controls for sources in their states.

II. Emissions Reductions from Specific EGUs are Reasonable

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

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

The following discussion addresses each of the four factors with respect to the strategy of controlling specific EGUs. Information is taken primarily from the MANE-VU Reasonable Progress Report and MANE-VU BART reports.

Costs of Compliance

Technologies to control the precursors of regional haze are commercially available.[1] Since EGUs are the most significant stationary source of SO_2, NO_x, and PM, they have been subject to extensive federal and state regulations to control all three pollutants. The technical feasibility of control technologies has been successfully proven for a large number of small (say, 100MW) to very large boilers (over 1,000 MW) using different types of coal used. Over the last few years, a large amount of cost data have also become available that clearly indicated that many technologies

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

provide substantial and extremely cost effective reductions.

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

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

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

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

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

quality modeling for ozone and haze state implementation plans.

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

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

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

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

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

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

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

Time Necessary for Compliance

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

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

Energy and Non-Air Quality Environmental Impacts of Compliance

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

Remaining Useful Life of Any Potentially Affected Sources

It is highly unlikely that additional EGU controls required under this SIP would have any impact on the remaining useful life of a particular EGU. As noted in the MANE-VU Reasonable Progress Report, remaining useful life estimates of EGU boilers indicate a wide range of operating lifetimes,

depending on the size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies range to 50 years or more. Additionally, implementation of regulations over the years has resulted in retrofitting that has ultimately increased the expected life span of many EGUs. The lifetime of an EGU may be extended through repair, re-powering, or other strategies if the unit is more economical to run than to replace with power from other sources. This may be particularly likely if the unit serves an area which has limited transmission capacity available to bring in other power. The remaining useful life of a unit should not be confused with the economic decision of whether or not to continue operating a unit or to re-power or replace it. The cost of environmental compliance is only one of many factors involved in such a decision.

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

The MANE-VU contribution Assessment documented source apportionment analyses that linked visibility impairment in MANE-VU Class I areas with SO_2 emissions from sources burning fuel oil. The reasonable assumption underlying the low-sulfur fuel oil strategy is that refiners can, by 2018, produce home heating and fuel oils that contain 50 percent less sulfur for the heavier grades (#4 and #6 residual oil), and a minimum of 75 percent and maximum of 99.25 percent less sulfur in #2 fuel oil (also known as home heating oil, distillate, or diesel fuel) at an acceptably small increase in price to the consumer.

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

MANE-VU's Reasonable Progress Report identified switching to a lower sulfur oil as an available SO_2 control option that would achieve 50 to 90 percent reductions in SO_2 emissions from ICI Boilers. The report also noted that home heating oil use generates an estimated 100,000 tons of SO_2 emissions in the Northeast each year, and that SO_2 emissions would decline in proportion to reductions in fuel sulfur content.The following discussion summarizes information concerning the four factors for the low-sulfur fuel strategy.

Costs of Compliance

The MANE-VU Reasonable Progress report noted that because of requirements for motor vehicle fuels, refineries have already performed the capital investments required for the production of low sulfur diesel and ultra-low sulfur diesel. The report estimated a cost per ton of SO_2 removed by switching to lower sulfur fuel would range from $554 to $734 per ton (Converted from 2001 to 2006 dollars using a conversion factor of

1.1383 www.inflationdata.com). (See Chapter 8 of the Reasonable Progress Report.) In some seasons and some locations, low sulfur diesel is actually cheaper than regular diesel fuel.

While costs for these emissions reductions are somewhat uncertain, they are quite reasonable in comparison to costs of controlling other sectors. Some MANE-VU states are proceeding with low-sulfur oil requirements much sooner than 2018; however, all of the MANE-VU states agreed that a low-sulfur oil strategy is both reasonable and achievable by 2018. MANE-VU has concluded that the cost of requiring lower sulfur fuel is reasonable.

Time Necessary for Compliance

MANE-VU's Reasonable Progress Report indicated that furnaces and boilers would not have to be retrofit and would not require expensive control technology to burn ULSD distillate fuel oil. Therefore, the time necessary for compliance would be determined by the availability of the fuel.

The MANE-VU Reasonable Progress Report notes that nationally, more ULSD is produced than both LSD and high sulfur fuel. The report concludes that the US has the infrastructure to produce adequate stocks of LSD and ULSD. The NESCAUM Low Sulfur Heating Oil Report[5] also notes that the federal rules for heavy duty highway diesel fuel are flexible, so that if there is a shortage of 15 ppm fuel, the 15 to 500 ppm fuel could be used to relieve the shortage. With this flexibility, the report concludes that the likelihood of a fuel shortage in the short term due to use of ULSD for heating oil is reduced. The volatile nature of heating supply and demand presents unique challenges to the fuel oil industry. The success of a low sulfur fuel oil program is predicated on meeting these challenges.

The Northeast states are assessing a variety of business strategies and regulatory approaches that could be used to minimize any potential adverse supply and price impacts that could result from a regional 500 ppm sulfur standard for heating oil. Suppliers can increase pre-season reserves and look to increase imports from offshore refiners producing low sulfur product. Blending domestically produced biodiesel into heating oil offers opportunity to reduce imports, stabilize supplies and minimize supply-related price spikes. Air quality regulators are also considering permitting seasonal averaging of sulfur content which would allow higher sulfur imports to be brought to the Northeast market during periods of peak demand. Over the course of the year, the higher sulfur fuel would

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

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

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

Energy and Non-Air Quality Environmental Impacts of Compliance

Reducing the sulfur content of fuel oil would have a variety of beneficial consequences for boilers and furnaces using the fuel, according to MANE-VU's Reasonable Progress Report. Low sulfur distillate fuel is cleaner burning and emits less particulate matter, which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings. The MANE-VU report cites a study by the New York State Energy Research and Development Authority (NYSERDA) that showed that boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm.

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

Remaining Useful Life of Any Potentially Affected Sources

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

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

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

6 The MANE-VU Statement concerning controls outside of MANE-VU titled, Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Request for a Course of Action by States Outside of MANE-VU Toward Assuring Reasonable Progress" dated June 20, 2007.

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

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

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

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

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

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

Emissions from ICI boilers are currently governed by multiple State and federal regulations under the Titles I, III, and IV of the Clean Air Act. The

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

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

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

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

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

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

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

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

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

Post-combustion SO2 control is accomplished by reacting the SO2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use depending on the technology used. SO2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) and/or "Scrubbers" and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and reagent utilization (once-through versus regenerable).

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

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

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

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

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

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

capacity in the world and the U.S.

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

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

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

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

Costs of Compliance

Industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities. Thus cost estimates for the same technologies will generally span a relatively larger range, and costs for

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

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

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

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

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

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

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

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

Cost of Technologies for Industrial Boilers[10]

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

Time Necessary for Compliance

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

For combustion based and post-combustion based engineering and construction leads times will vary between 2 and 5 years depending on the size of the facility and specific control technology selected. Generally, sources are given a 2-4 year phase-in period to comply with new rules. Under the previous Phase I of the NO_X SIP Call, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase II of the

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

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

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

Energy and Non-Air Quality Environmental Impacts of Compliance

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

The MANE-VU reasonable progress report notes, "Reducing the sulfur content of distillate fuel oil has a variety of beneficial consequences for ICI boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings." (p.4-14)

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

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

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

content of distillate fuel oil has a variety of beneficial consequences for ICI boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings." (p. 4-14)

Remaining Useful Life of Any Potentially Affected Sources

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

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

References

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