Reasonable Progress for Class I Areas in the Northern Midwest – Factor Analysis

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Draft Final Technical Memorandum

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Scope of Document

This document provides an initial analysis of the five factors which must be considered in establishing a reasonable progress goal toward achieving natural visibility conditions in mandatory Class I areas. These factors were examined both for existing (“on the books”) control programs and several candidate control measures for priority pollutants and emission sources. The results of this report are intended to inform policymakers in setting reasonable progress goals for the four northern Class I areas in Minnesota and Michigan, pursuant to the requirements of the Regional Haze Rule. A number of entities have participated in the design and review of this study, including air pollution control agencies in Michigan, Wisconsin, Minnesota, and other states, as well as by the National Park Service, the U.S. Forest Service, Tribes, the Midwest Regional Planning Organization (MRPO), and other Regional Planning Organizations.

This document does not address policy issues, set reasonable progress goals, or recommend a long-term strategy for regional haze. The States of Minnesota and Michigan will establish reasonable progress goals and develop a long-term strategy in consultation with other states. Separate documents will be prepared by the States which address the reasonable progress goals, each state's share of emission reductions, and coordinated emission control strategies. These documents will be based on the information contained in this and other technical reports (e.g., “Regional Haze in the Upper Midwest: Summary of Technical Information,” January 9, 2007).

Disclaimer

The analysis described in this document has been funded by the Lake Michigan Air Directors Consortium and the Minnesota Pollution Control Agency. It has been subject to review by these organizations and other organizations listed above. However, the report does not necessarily reflect the views of the sponsoring and participating organizations, and no official endorsement should be inferred.

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List of Acronyms

ACT	Alternative Control Techniques
ALAPCO	Association of Local Air Pollution Control Officials
ANPRM	Advance Notices of Proposed Rulemaking
APU	Auxiliary Power Unit
ASOA	Anthropogenic Seconday Organic Aerosol
B20	Biodiesel in a 20% blend with petroleum diesel
B40	Biodiesel in a 40% blend with petroleum diesel
BACT	Best Achievable Control Technology
BART	Best Available Retrofit Technology
BenMAP	Benefits Mapping and Analysis Program
BMP	Best Management Practice
BSOA	Biogenic Secondary Organic Aerosol
CAIR	Clean Air Interstate Rule
CAMx	Comprehensive Air Modeling with extensions
CARB	California Air Resources Board
CUECost	Coal Utility Environmental Cost
E10	Ethanol in a 10% bled with petroleum diesel
EC	Elemental Carbon (particulate)
EGU	Electric Generating Unit
EGU1	Possible cap for NOX and SO2 for midwest region; NOx limited to 0.10 lb/mmBtu of fossil fuel consumption, SO2 limited to 0.15 lb/mmBtu of fossil fuel consumption
EGU2	Possible cap for NOX and SO2 for midwest region; NOx limited to 0.07 lb/mmBtu of fossil fuel consumption, SO2 limited to 0.10 lb/mmBtu of fossil fuel consumption
EIA	Energy Information Administration
ENVIRON Report	Evaluation of Candidate Mobile Source Control Measures for LADCO States in 2009 and 2012
FCCU	Fluid Catalytic Cracking Unit
FPRM	Federal Particulate Reference Method
GR	Gas Reburn
HAP	Hazardous Air Pollutants
HDDV	Heavy-Duty Diesel Vehicles
ICAC	Institute of Clean Air Companies
ICI	Industrial, Commercial, and Institutional
ICI Workgroup Strategy	Strategy to control SO2 and NOX regional emissions; specific limitations are a function of boiler type and size, and fuel type; overall requires approximately a 77% reduction in SO2 emissions and a 70% reduction in NOx emissions
ICI1	Strategy to control SO2 and NOX regional emissions; requires a 40% reduction in SO2 emissions and a 60% reduction in NOx emissions, from the 2018 baseline emissions
IL	Illinois
IN	Indiana
IPM	Integrated Planning Model
kW	Kilowatt
LADCO	Lake Michigan Air Directors Consortium
LEC	Low-Emission Combustion
LNB	Low NOx burners
LRAPA	Lane Regional Air Protection Agency
LSD	Lime Spray Dryer (scrubber)
LSFO	Limestone Forced Oxidation (scrubber)
MACT	Maximum Available Control Technology
MCDI	Midwest Clean Diesel Initiative
MI	Michigan

List of Acronyms

mmBtu	Million British Thermal Units
MN	Minnesota
MO	Missouri
MRPO	Midwest Regional Planning Organization
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
ND	North Dakota
NEEDS	National Electric Energy System Database
NEI	National Emission Inventory
NESCAUM	Northeast States for Coordinated Air Use Management
OFA	Overfire Air
OH	Ohio
OTC	Ozone Transport Comission
POC	Primary Organic Carbon (particulate)
PSAT	Particle Source Apportionment Tool
RIA	Regulatory Impact Assessment
RICE	Reciprocating Internal Combustion Engines
SCR	Selective Catalytic Reduction
SD	South Dakota
SDA	Spray-Dry Absorbers
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
STAPPA	State and Territorial Air Pollution Program Administrators
TN	Tennessee
TSE	Truck Stop Electrification
U.S. EPA	United States Environmental Protection Agency
VISTAS	Visibility Improvement State and Tribal Associations of the Southeast
VOC	Volatile Organic Compounds
WFGD	Wet Flue Gas Desulfurization
WI	Wisconsin

Chemical Symbols

(NH4)(HSO4)	ammonium sulfate
(NH4)(NO3)	ammonium nitrate
(NH4)2SO4	ammonium sulfate
CO	carbon monoxide
CO2	carbon dioxide
HC	hydrocarbons
NH3	ammonia
NH4+	ammonium
NO3-	nitrate
NOx	nitrogen oxide
PM2.5	particulate matter (2.5 micrometers or smaller)
SO2	sulfur dioxide

1. Introduction

The Regional Haze Rule requires States to set reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. The first reasonable progress goals will be established for the planning period 2008 to 2018. The states of Minnesota and Michigan, along with the Midwest Regional Planning Organization (MRPO), representatives of other states, tribal governments, and federal agencies, are working to address visibility impairment due to regional haze in four northern-Midwest Class I areas. These areas, shown in Figure 1-1, are the Boundary Waters Canoe Area Wilderness, Voyageurs National Park, Isle Royale National Park, and the Seney Wilderness Area.

The Regional Haze Rule identifies four factors which should be considered in evaluating potential emission control measures to meet visibility goals. These are as follows:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of any existing source subject to such requirements

In addition, the U.S. Environmental Protection Agency's regional haze rule identifies a fifth factor which should be considered. This is the uniform rate of visibility improvement needed to attain natural conditions by 2064.

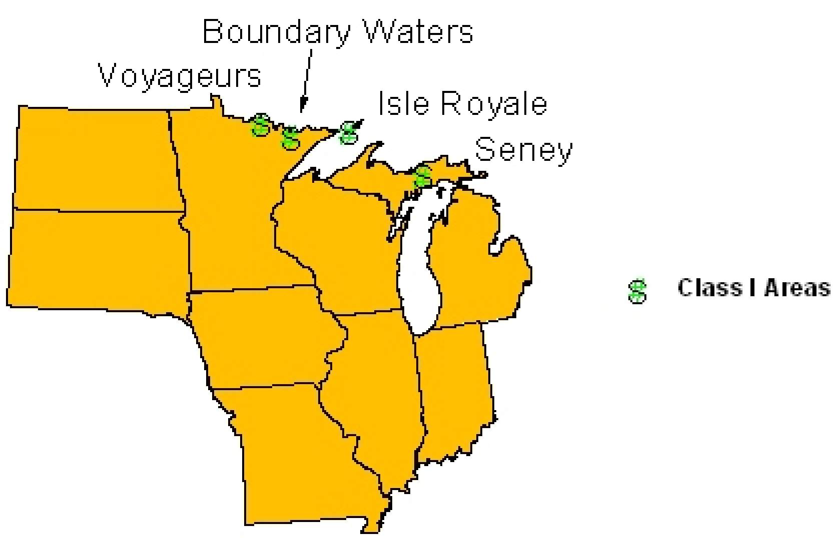

Figure 1. Northern-Midwest Class I Areas.

The purpose of this report is to analyze these reasonable progress factors for several possible control strategies intended to improve visibility in the northern-Midwest Class I areas:

- SO_2 and NO_X emissions from electric generating units (EGUs)
- SO_2 and NO_X emissions from Industrial, commercial and institutional (ICI) boilers
- Ammonia from agricultural operations
- NO_X emissions from onroad and nonroad mobile sources
- NO_X emissions from reciprocating engines and turbines

In addition, an analysis is provided of existing ("on the books") control programs:

- Clean Air Interstate Rule (CAIR)
- BART for available States (i.e., MI, MN, WI, and ND)
- Maximum Available Control Technology (MACT) standards for combustion turbines and industrial boilers
- On-road mobile source programs (i.e., 2007 Highway Diesel Rule, Tier II/Low Sulfur Gasoline)
- Non-road mobile source programs (i.e., Non-road Diesel Rule, Control of Emissions from Unregulated Non-road Engines, Locomotive/Marine ANPRM)

The current factor analysis has been carried out in conjunction with other related work being conducted by the MRPO (also known as the Lake Michigan Air Directors Consortium, LADCO) and the Midwest states, and within the overall framework described in the document, "Approaches for Meeting Reasonable Progress for Visibility at Northern Class I Areas."[1] In addition, the methodology for this analysis has been developed in a collaborative process involving state representatives, the MRPO, and other stakeholders. On June 1, 2007, EPA issued guidance related to setting reasonable progress goals ("Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program"). A preliminary review of EPA's guidance document indicates that the approach taken in this report is consistent with the guidance.

This report is organized in six sections. Section 2 gives a summary of background information from other studies that provided the basis for selecting the priority pollutants and emission sources to be analyzed in this factor analysis. Section 3 describes the general methodology used in the factor analysis. Section 4 gives results of the factor analysis for on-the-books controls, and Section 5 gives factor analysis for potential future regional haze controls. Section 6 summarizes the results and conclusions of the factor analysis.

2. Background

To support planning efforts for regional haze in the northern-Midwest Class I areas, the States prepared a summary of technical information.[2] This summary document includes a conceptual model of haze, the technical basis for visibility analysis, and the effectiveness of control measures in improving visibility. A key part of the conceptual model of haze is a contribution assessment based on air quality data analyses and photochemical modeling. The contribution assessment identifies important states and sources contributing to visibility impairment in the northern-Midwest Class I areas.

The most important contributing states are Michigan, Minnesota, and Wisconsin, as well as surrounding states, such as the Dakotas, Iowa, Missouri, Illinois, and Indiana. For example, Figure 2-1 presents the results of composite back trajectories for light extinction on the 20% worst visibility days. The orange areas are where the air is most likely to come from on poor air quality days, and the green areas are where the air is least likely to come from on poor air quality days. As can be seen, bad air days are generally associated with transport from regions located to the south of these class I areas.

The most important contributing pollutants and source sectors are SO_2 emissions from electrical generating units (EGUs) and certain non-EGUs, which lead to sulfate formation, and NOx emissions from a variety of source types (e.g., motor vehicles), which lead to nitrate formation. Ammonia emissions from livestock waste and fertilizer applications are also

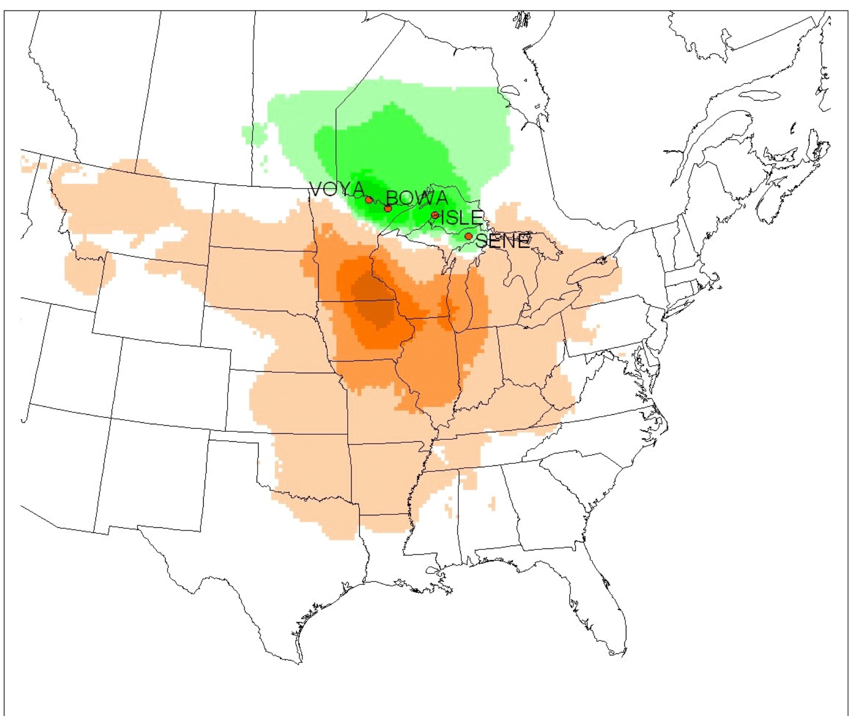

Figure 2-1. Composite Back Trajectories for Light Extinction on the 20% Worst Days.

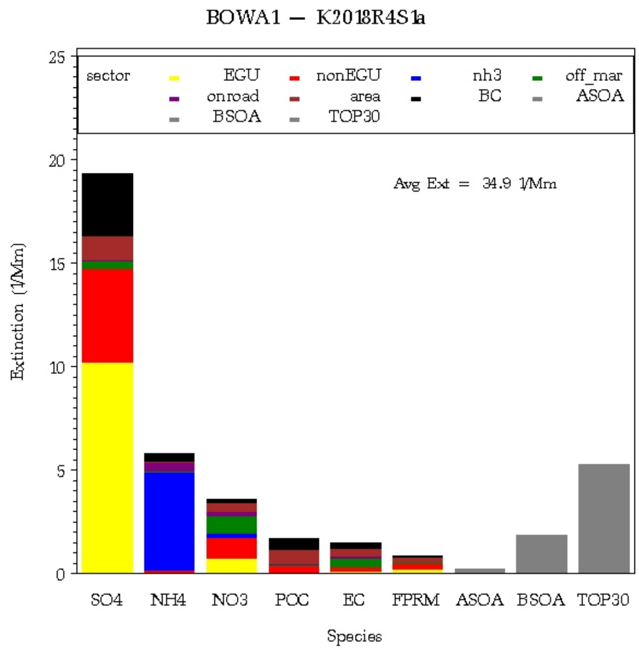

Figure 2-2. Results of 2018 PSAT modeling for Boundary Waters Canoe Area.

important, especially for nitrate formation. For example, Figure 2-2 presents the results of particle source apportionment tool (PSAT) modeling for the Boundary Waters Canoe Area for 2018. As can be seen, sulfates are the dominant species indicating the importance of SO_2 emissions.

The modeling analyses were based on emissions inventories for 2002 and 2018. Figure 2-3 and Table 2-1 summarize the major contributors to the SO_2, NO_X, and ammonia emissions inventories in 2002 and 2018 for Michigan, Minnesota, and Wisconsin – the three

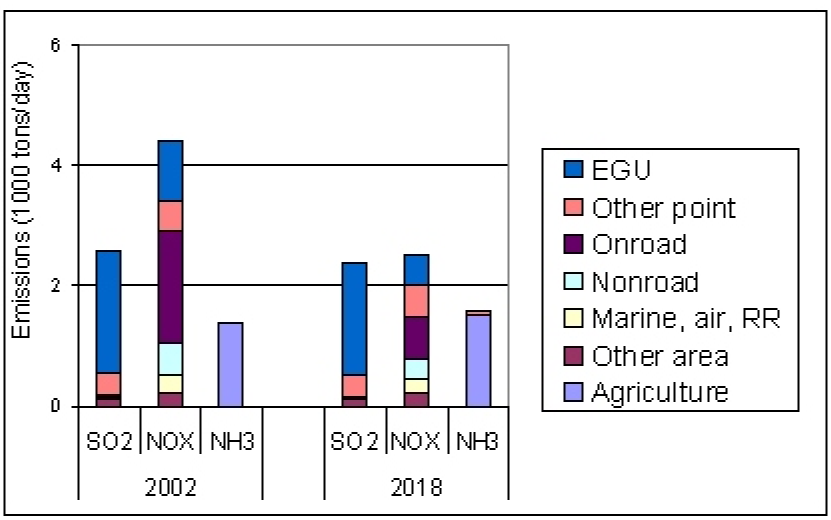

Figure 2-3. Summary of SO_2, NO_X, and NH_3 emissions in Michigan, Minnesota, and Wisconsin.

Table 2-1. Regional Emissions Summary

	Estimated emissions in the 3-state region surrounding the northern Midwest Class I areas (tons/day)				Estimated emissions in a larger 9-state region (tons/day)			
	SO2		NOX		SO2		NOX	
	2002	2018	2002	2018	2002	2018	2002	2018
Point sources								
Electric generating units	2,023	1,755	1,013	514	7,489	4,952	3,507	1,564
Industrial, commercial and institutional boilers	227	215	136	132	674	641	413	400
Reciprocating engines			71	66			264	254
Turbines			19	20			42	45
Other point sources	156	196	257	287	815	948	616	669
Area sources	113	112	208	225	594	588	462	515
Mobile sources								
Onroad			1,862	708			4,529	1,250
Nonroad	51	4	557	338	123	19	1,437	1,288
Marine, aircraft, railroad	21	11	294	222	44	20	969	666
Total	2,592	2,294	4,417	2,512	9,739	7,168	12,239	6,650

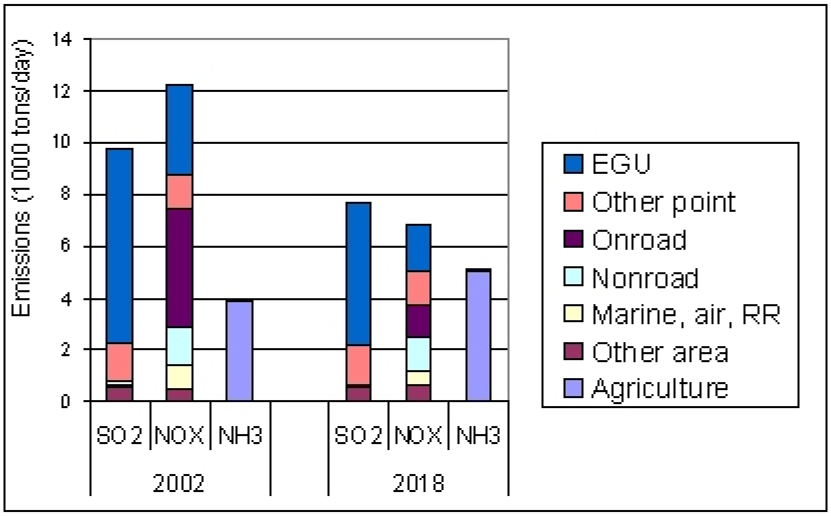

Figure 2-4. Summary of SO_2, NO_X, and NH_3 emissions in Michigan, Minnesota, Wisconsin, Illinois, Indiana, Iowa, Missouri, North Dakota, and South Dakota.

states nearest to the northern-Midwest Class I areas. (Appendix A provides state level emissions estimates for major emission categories.) These estimates are derived from the MRPO Base K emissions inventory for 2002, and MRPO projections of 2018 emissions with existing on-the-books control measures.[3,a] Figure 2-4 gives a similar emission summary for the nine-state region to the South and West of the Midwest Class I areas, including Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, and Wisconsin. As Figure 2-3 shows, EGUs account for the bulk of SO_2 emissions in the three states in 2002, and are also projected to account for the bulk of SO_2 emissions in 2018. Mobile sources contribute the bulk of NO_X emissions in 2002, followed by EGUs. NO_X emissions from both EGU and mobile sources are projected to decline between 2002 and 2018, but they are still projected to be the largest sources of NO_X in 2018. Agricultural sources account for the bulk of ammonia emissions in both 2002 and 2018.

A preliminary CAMx model sensitivity analysis has been carried out to estimate the potential impacts of SO_2, NO_X, and NH_3 emission reductions on light extinction in the northern Midwest Class I areas.[4] This analysis evaluated the impacts of 10% across the board emission reductions for SO_2, NO_X, and NH_3. Results of the sensitivity analysis are presented in Table 2-2. A 10% reduction in SO_2 emissions is predicted to reduce light extinction from sulfate particulate matter by 7.7 to 8.9%, and overall particulate light extinction by 1.3 to 3.5% in the northern Midwest Class I areas. The SO_2 emission reduction is predicted to increase extinction of nitrate

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[a] The EGU projections used in this study are taken from the VISTAS 2.1.9 version of IPM, which was developed in July 2005. In January 2007, EPA prepared new EGU projections (i.e., 3.0 version of IPM). The new EGU projections reflect lower 2018 SO_2 emissions for the 3-state region (about 500 TPD less). The MRPO is currently updating its regional modeling inventory to reflect a more current base year (2005) and improved future year emission estimates, including use of the new EGU projections. The new inventory will be available in mid-2007.

particulate matter by 2.4 to 3.2%. This is because less NH_3 would be bound to sulfate in the form of ammonium sulfates [$(NH_4)_2SO_4$ or $NH_4(HSO_4)$], making more NH_3 available for the formation of ammonium nitrate (NH_4NO_3). A 10% NO_X emission reduction is predicted to reduce light extinction from nitrate particulate matter (mainly NH_4NO_3) by 9.7 to 11.3%, and overall particulate light extinction by 2.4 to 2.8%. A 10% NH_3 emission reduction is predicted to reduce light extinction from NH_4NO_3 by 7.7 to 9.3%, and overall particulate light extinction by 2.0 to 2.7% at the northern Midwest Class I areas.

Table 2-2. CAMx Model Sensitivity Analysis of the Impacts of SO_2, NO_X, and NH_3 Emission Reductions on Visibility

		Impacts on predicted light extinction (% change)				
Change in emissions	Particulate component	Boundary Waters	Voyageurs	Isle Royale	Seney	Average
10% reduction in SO_2[a]	Sulfate	-8.6	-7.7	-8.5	-8.9	-8.4
	Nitrate	2.4	3.2	2.5	3.1	2.8
	Overall	-2.4	-1.3	-2.6	-3.5	-2.5
10% reduction in NO_X[a]	Sulfate	-0.1	0.3	-0.0	0.1	0.1
	Nitrate	-9.7	-10.1	-10.1	-11.3	-10.3
	Overall	-2.4	-2.8	-2.4	-2.6	-2.5
10% reduction in NH_3[a]	Sulfate	-0.5	-0.5	-0.9	-0.8	-0.7
	Nitrate	-7.9	-9.4	-7.7	-9.3	-8.6
	Overall	-2.0	-2.7	-2.1	-2.5	-2.3

[a]Each test entailed a 10% across-the-board reduction in 2018 emissions of the indicated pollutant, without any other change to the emissions inventory.

The sensitivity results give a somewhat different perspective from the PSAT results shown in Figure 2-2, with respect to the potential relative impacts of NO_X and SO_2 controls. For example, in the PSAT results for Boundary Waters (Figure 2-2), the estimated light extinction from sulfate particulate dominates is much larger than the estimated light extinction from nitrate particulate. However, based on the sensitivity results for Boundary Waters, a 10% reduction in NO_X is projected to produce the same overall light extinction impact as a 10% reduction in SO_2. This is partly because the reduction in SO_2, while reducing sulfate particulate, is projected to also result in a small increase in nitrate particulate. However, it must be noted that the source apportionment (PSAT) and source sensitivity are not the same, and the results are expected to differ. The PSAT results represent absolute model values, while the sensitivity results represent relative model values. The relative model values may be more appropriate given that they reflect EPA's modeling guidance and correct for model performance problems such as underprediction of nitrates.

3. Methodology

The methodology for this factor analysis was developed in a collaborative process involving the MRPO, state representatives, the National Park Service, and the U.S. Forest Service.[5] A two pronged approach was adopted, comprising a broad category-level analysis coupled with an in-depth analysis of selected individual sources.

The category-level analysis addresses the overall impacts of different emission control strategies on a broad class of emission sources, such as electric generating units (EGUs); or industrial, commercial and institutional (ICI) boilers. These control strategies generally involve an emission cap or a percentage rollback in overall emissions, both of which allow emissions trading among the sources in a given geographical region.

Two regions were selected for analysis, as illustrated in Figure 3-1. A three-state region (shown in brown) includes Michigan, Minnesota, and Wisconsin, which immediately surround the northern-Midwest Class I areas. A nine-state region includes these three states and adds six surrounding states (shown in yellow) – North and South Dakota, Iowa, Missouri, Illinois, and Indiana.

The in-depth analysis focused on the impacts of applying pollution control devices to selected individual facilities. These were used to help evaluate how category-level strategies will potentially apply to individual sources and to evaluate the uncertainties of the category-level analysis.

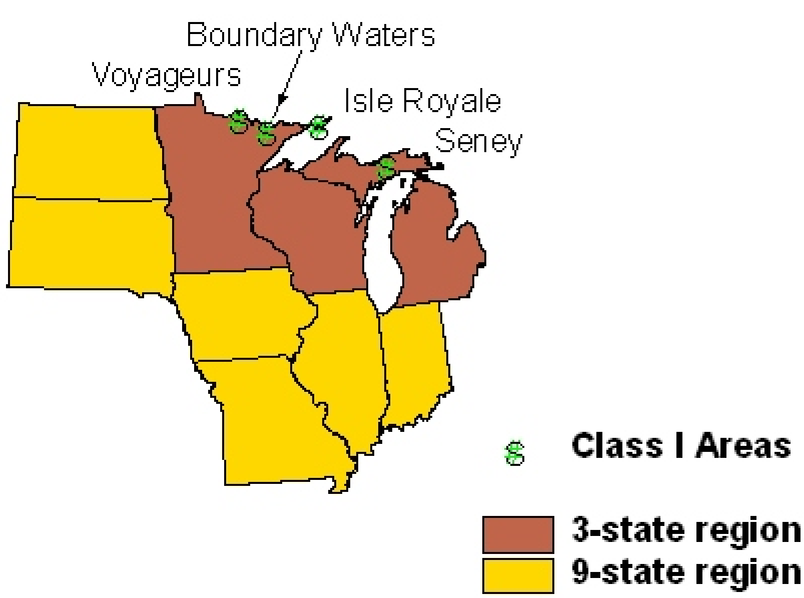

Figure 3-1. Geographic regions for the factor analysis.

Some additional individual sources were selected from source-types which were not part of the category-level analyses. The analyses of these facilities were designed to ensure that opportunities for cost-effective visibility improvements were not overlooked.

The first step in the technical evaluation of control measures for a source category was to establish the future emissions baseline with on-the-books regulations. This baseline was used to assess the progress toward the reasonable further progress goal with only on-the-books controls. The future baseline also provides a frame of reference to estimate the amount of emissions available for additional control.

The primary timeframe for the analysis is the 2018 reasonable progress milestone. However, potential emission reductions by 2012 will also be evaluated. Estimates of 2012 and 2018 baseline emissions for various emission source categories have been developed by the MRPO. The control technologies to meet on-the-books controls were identified based on the technical support documents and other background information published in support of the applicable regulations.

Once the baseline level of control in 2018 (and 2012) was identified, a list of potential additional control technologies was compiled from a variety of sources, including control techniques guidelines published by the EPA, emission control cost models such as AirControlNET and CueCost, Best Available Retrofit Technology (BART) analyses, LADCO White Papers, and a menu of control options developed by the National Association of Clean Air Agencies (NACAA – formerly STAPPA and ALAPCO).[6] The menu of options for each source category was then narrowed to a set of technologies that would achieve the emission reduction target under consideration. The following sections discuss the methodology used to analyze each of the regional haze factors for the selected technologies.

3.1 Factor 1 – Costs

Control costs include both the capital costs associated with the purchase and installation of retrofit and new control systems, and the net annual costs (which are the annual reoccurring costs) associated with system operation. The basic components of total capital costs are direct capital costs, which includes purchased equipment and installation costs, and indirect capital expenses. Direct capital costs consist of such items as purchased equipment cost, instrumentation and process controls, ductwork and piping, electrical components, and structural and foundation costs. Labor costs associated with construction and installation are also included in this category. Indirect capital expenses are comprised of engineering and design costs, contractor fees, supervisory expenses, and startup and performance testing. Contingency costs, which represent such costs as construction delays, increased labor and equipment costs, and design modification, is an additional component of indirect capital expenses. Capital costs also include the cost of process modifications. Annual costs include amortized costs of capital investment, as well as costs of operating labor, utilities, and waste disposal. For fuel switching options, annual costs include the cost differential between the current fuel and the alternate fuel.

For Factor 1, results of the cost analysis are expressed in terms of total cost-effectiveness, in dollars per ton of emissions reduced. Cost effectiveness is also calculated in terms of dollars per deciview by combining results from the Factor 1 and Factor 5 analyses.

A relevant consideration in a cost-effectiveness calculation is the economic condition of the industry (or individual facility if the analysis is performed on that basis). Even though a given cost-effectiveness value may, in general, be considered “acceptable,” certain industries may find such a cost to be overly burdensome. This is particularly true for well-established industries with low profit margins. Industries with a poor economic condition may not be able to install controls to the same extent as more robust industries. A thorough economic review of the source categories selected for the factor analysis is beyond the scope of this project.

3.2 Factor 2 – Time Necessary for Compliance

For Factor 2, we evaluated whether a potential control strategy could be fully implemented by the target dates of 2018 or 2012, or how much of an emission reduction can be achieved by these target years. The time for compliance was defined to include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis also included the availability of production and labor capacity for fabricating and installing control devices, as well as the need for staging the installation of multiple control devices at a given facility.

For mobile sources, control strategies may not require retrofits to existing emission sources, but instead rely on the turnover of vehicle fleets, or replacement of nonroad engines. In these cases, the Factor 2 analysis focuses on quantifying the fraction of the source category which would use the new technology by the target date, and the emission reduction that would result. For agricultural sources of ammonia, Factor 2 was analyzed in terms of time required to fully implement technical control strategies or to grow vegetative buffers.

3.3 Factor 3 – Energy and Other Impacts

Table 3.3-1 summarizes the energy and environmental impacts analyzed under Factor 3. We evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, other environmental impacts. Other non-air quality environmental impacts considered included solid waste generation, wastewater discharge, acid deposition, nitrogen deposition, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were calculated as part of Factor 1, and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility. Energy needs and non-air quality impacts of identified control technologies were aggregated to estimate the energy impacts for the specified industry sectors. However, indirect energy impacts were not considered, such as the different energy requirements to produce a given amount of coal versus the energy required to produce an equivalent amount of natural gas. For completeness, information on other air quality environmental impacts was provided in Factor 3 (e.g., improvement in ambient $PM_{2.5}$ and ozone concentrations due to reductions in regional NO_X and SO_2 emissions).

Table 3.3-1 Summary of Energy and Environmental Impacts Evaluated Under Factor 3

Energy Impacts
Electricity requirement for control equipment and associated fans
Steam required
Fuel required
Environmental Impacts
Waste generated
Wastewater generated
Additional CO_2 produced
Reduced acid deposition
Reduced nitrogen deposition
Benefits from reductions in $PM_{2.5}$ and ozone, where available
Impacts Not Included
Impacts of control measures on boiler efficiency
Energy required to produce lower sulfate fuels
Secondary environmental impacts to produce additional energy (except CO_2) produced

3.4 Factor 4 – Remaining Equipment Life

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a particular emission source is less than the lifetime of the pollution control device (such as a scrubber) that is being considered. In this case, the capital cost of the pollution control device can only be amortized for the remaining lifetime of the emission source. Thus, if a scrubber with a service life of 15 years is being evaluated for a boiler with an expected remaining life of 10 years, the shortened amortization schedule will increase the annual cost of the scrubber.

In general, the category-level control strategies evaluated in this study are market-based strategies, which would allow trading among emission sources to achieve a region-wide target.

The affected industries are expected to install control devices in a a manner that minimizes overall costs to the industry. Under this scenario, it is expected that control devices would not be installed on emission sources with short life expectancies.

In the analyses of individual facilities, the ages of major pieces of equipment were determined where possible, and compared with the service life of pollution control equipment. The impact of a limited useful life on the amortization period for control equipment was then evaluated, along with the impact on annualized cost-effectiveness.

3.5 Factor 5 – Visibility Impacts

Visibility impacts of potential emission control strategies were estimated using the results of the MRPO's modeling analyses. For the examination of existing control measures, the visibility impacts were calculated directly by the modeling for 2018. For the examination of potential additional control measures, visibility impacts were derived using the results of PSAT analyses and sensitivity analyses for 2018. In the PSAT analyses, the MRPO estimated the contribution of different emission source groups to the overall light extinction coefficient at each Class I area.[7] Sources were grouped by major emission source categories and by source regions (generally states). In addition, extinction contributions were modeled for the sulfate ($SO_4^{=}$), nitrate (NO_3^{-}), and ammonium (NH_4^{+}) fractions of particulate matter, as well as other particulate components. The MRPO sensitivity analysis evaluated the impacts of 10% across-the-board reductions in emissions of SO_2, NO_X, and NH_3. The MRPO also computed light extinction contributions for the several high-emitting individual facilities in the region.

A rollback approach was used to estimate the visibility impacts of potential future emission control strategies for SO_2 and NO_X emissions from different source categories. In this approach, the extinction coefficient is assumed to change in proportion to the change in emissions from the source category. Impacts were calculated on a source-category-specific, state-specific, and chemical species fraction basis. The algorithm used for these rollback calculations is as follows:

$$RX_{i,j,k} = \frac{Rdn_{i,j,k}}{Emis_{i,j,k}} \times \frac{PSAT_{i,j,k}}{PSAT_{i,tot}} \times \frac{SensXChg_i}{SensEChg}$$

where:

$RX_{i,j,k}$ = estimated reduction in extinction coefficient for pollutant i (SO_2, NO_X, or NH_3), category j, and source region k (Mm^{-1})

$Rdn_{i,j,k}$ = estimated emission reduction resulting from a control strategy for pollutant i, emission source category j and source region k (tons/year)

$PSAT_{i,j,k}$ = estimated contribution of emissions for the particulate species corresponding to pollutant i ($SO_4^{=}$ for SO_2, NO_3^{-} for NO_X, and NH_4^{+} for NH_3), for category j, and source region k to the extinction coefficient, based on PSAT modeling for 2018 (Mm^{-1})

$PSAT_{i,tot}$ = total contribution pollutant i from PSAT modeling (Mm^{-1})

$Emis_{i,j,k}$ = projected emission rate in 2018 for pollutant i, source category j, and source region k, with on-the-books controls but before the application of any additional control strategy (tons/year)

$SensXChg_i$ = Predicted change in extinction based on the results of CAMx sensitivity analysis for pollutant i (Mm^{-1}), as shown in Table 3.5-1

SensEChg = Fractional change in emissions in the sensitivity analysis (10%)

The above approach assumes a linear relationship between the emissions of precursor pollutants and the amount of light extinction that will result from these precursors. This simplifying assumption is subject to considerable uncertainty. In addition, the above approach draws on sensitivity analyses and PSAT analyses using the CAMx model, and is subject to the uncertainties of these model analyses. As a result, this approach and can under-predict or over-predict visibility impacts.. However, it provides a mechanism for estimating visibility impacts as a prelude to more-detailed modeling.

Table 3.5-1. Sensitivity Factors Used in Calculating Extinction Changes

	Light extinction change per 10% reduction in emissions (Mm^{-1})[a]			
Pollutant	Boundary Waters	Voyageurs	Isle Royale	Seney
SO_2	–1.7	–1.0	–2.0	–3.4
NO_X	–1.7	–2.0	–1.9	–1.9
NH_3	–1.4	–1.9	–1.6	–2.5

[a]Based on CAMx sensitivity analyses (discussed in Section 2). Table 2-2 has given these changes as a percentage of the projected baseline light extinction.

The impacts in terms of extinction coefficient were then converted to deciviews using the following equation, based on the definition of a deciview:

$$RdV = 10 \times \left[\ln\left({BX}/{10} \right) - \ln\left({(BX - RX)}/{10} \right) \right]$$

where:

RdV = estimated reduction in visibility degradation at a particular Class I area (deciviews)

BX = total extinction coefficient at the Class I area in 2018, from all sources (Mm^{-1})

RX = reduction in extinction coefficient for a particular source or source category (Mm^{-1})

The visibility impacts in this report are generally expressed in terms of deciviews.

In addition to the extinction and deciview estimates, the impacts of pollution control strategies were also quantified in terms of the change in emissions divided by distance (Q/d). This information can be useful in evaluating the impacts for sources which have not been included in the 2018 PSAT analysis. For a group of sources or facilities, the Q/d factor is computed as follows:

$$\left({Q}/{d} \right)_m = \sum \left[\frac{Rdn_n}{Dist_n} \right]$$

where:

(Q/d) = the sum of emissions divided by distance for a given group of emission sources and in relation to a given Class I area (tons/mile)

Rdn_n = the emission reduction at source n, within the group of emission sources (tons)

$Dist_n$ = the distance from source n to the Class I area (miles)

4. Analysis of Existing Control Measures

A factor analysis was conducted for on-the-books and on-the-way Federal regulatory programs impacting priority sectors in the 3-State and 9-State regions. The purposes of this analysis were to:(1) assess the progress toward the reasonable progress goal with only on-the-books controls, and (2) provide a frame of reference to estimate the amount of emissions available for additional control.

The MRPO Base K/Round 4 Strategy Modeling emissions inventory applies these programs in their Scenario 1 2018 projections. Cost-effectiveness and emission reduction information were obtained from available documents (e.g., Regulatory Impact Analyses (RIAs), preliminary Best Available Retrofit Technology (BART) analyses for available facilities, and Advance Notices of Proposed Rulemaking (ANPRM)). Table 4-1 lists the programs included in the on-the-books analysis. In addition, the table lists the sources of information used to evaluate the impacts of these programs. Table 4-2 summarizes information on the projected impacts of these control measures relative to the four reasonable progress factors for regional haze.

Table 4-1. On-the-Books Control Measures Included in the Factor Analysis

Regulatory Program	Information Source
Clean Air Interstate Rule (CAIR)	CAIR RIA[8, 9]
BART	Company BART analyses, where available[10, 11]
Maximum Available Control Technology (MACT) standards	• Reciprocating Internal Combustion Engines (RICE) MACT Federal Register Notice[12] • Industrial Boilers and Process Heaters MACT Federal Register Notice[13]
On-road mobile source programs	• 2007 Highway Diesel Rule RIA[14] • Tier II Emissions Standards RIA[15] • Low Sulfur Gasoline RIA[15]
Non-road mobile source programs	• Non-road Diesel Rule RIA[16] • Control of Emissions from Unregulated Non-road Engines RIA[17] • Locomotive/Marine ANPRM[18]

4.1 Factor 1 – Costs

EPA has estimated that the cost of the CAIR program will range from \$720 to \$2,600 per ton of SO_2 or NO_X emissions reduced.[6,7] CAIR is the most recent of a number of existing cap-and-trade programs to reduce SO_2 and NO_X emissions from EGUs in the eastern U.S. Other cap-and-trade programs for SO_2 and NO_X include the Acid Rain Program and the NO_X SIP call for the ozone National Ambient Air Quality Standards (NAAQS).

Table 4-2. Summary of Five-Factor Analysis of On-The-Books Controls

	Factor 1	Factor 2		Factor 3		Factor 4
Control Strategy	Cost effectiveness ($/ton)	Percent Emission Reductions from 2002 baseline in 2018	Percent Emission Reductions from 2002 baseline at full implementation	Energy	Solid waste produced (1000 tons/year)	Remaining Useful Life
CAIR and other cap-and-trade programs (e.g., Acid Rain, NOX SIP Call)	$720 - $2,600	3-State SO2: 13% NOX: 75% 9-State SO2: 34% NOX: 79%	3-State SO2: 47% NOX: 75% 9-State SO2: 48% NOX: 80%	4.5% of total	2,383	The IPM model projects that 53 units will retire by 2018.
BART: Based on company BART analyses from MN and ND	$248 - $1,770					
Combustion MACTs	$1,477 - $7,611	9-State SO2: 10% NOX: 5%	9-State SO2: 10% NOX: 5%			
Highway vehicle programs	$1,300 - $2,300	3-State NOX: 83% 9-State SO2: 80%	3-State NOX: 83% 9-State SO2: 80%			
Nonroad mobile sources	($1,000) - $1,000	3-State NOX: 39% 9-State SO2: 27%	3-State NOX: 39% 9-State SO2: 27%	350 MM gallons of fuel saved		

The Midwest states have identified over 30 non-EGU facilities which would be subject to BART based on their estimated impacts on the northern Midwest Class I areas. These sources, listed in Table 4.1-1, include industrial boilers, petroleum refineries, steel plants, aluminum plants, cement plants, chemical manufacturing facilities, pulp and paper plants, and iron mines. Emission sources in Minnesota and North Dakota have prepared draft BART analyses, and some have proposed control technologies to meet the requirements of the BART program. The facilities proposing additional controls for BART are primarily EGUs. Based on control technologies proposed by the facilities, the draft BART analyses give a range of cost-effectiveness estimates from \$300 to \$1,770 per ton of emissions reduced. Appendix A presents additional details on facility-specific BART analyses. It must be noted that the states have not yet established thresholds for BART controls. Facilities may need to install more stringent controls than have been identified in the current BART analyses.

MACT standards for reciprocating internal combustion engines (RICE) are expected to reduce Hazardous Air Pollutants (HAP) through measures to improve combustion efficiency. These combustion changes are also expected to reduce NO_X emissions with a cost-effectiveness of about \$1,500 per ton of NO_X reduced. MACT standards for industrial, commercial, and institutional boilers and process heaters are expected to reduce HAP emissions as well as SO_2 emissions through sorbent injection controls. The cost per ton of SO_2 removed is estimated at about \$7,600.

The Unregulated Engine Rule is expected to produce cost savings of \$1,000/ton. This savings is expected to result from increased fuel economy in the non-road sector.

4.2 Factor 2 – Time Necessary for Compliance

Because emission sources can trade emission allowances to meet the CAIR limits, the timing and magnitude of emission reductions from the program will vary from state to state. The Integrated Planning Model (IPM) has been used to predict where and when pollution control technologies will be installed to meet the requirements of CAIR and other existing programs. Table 4-2 shows projected emission reductions in the Midwest from CAIR by 2018 and after the rule has been fully implemented.[a] Appendix A gives predicted emission reductions at the state level. These emission projections are based on the VISTAS-2.1.9 run of IPM. As Table 4-2 and Appendix A show, most of the CAIR NO_X emission reductions in the Midwest are expected to be realized by 2018, but most of the reductions for SO_2 are expected to occur between 2018 and 2026. Emission reductions for the other on-the-books control measures are expected to be realized prior to 2018.

[a] The EGU projections used in this study are taken from the VISTAS 2.1.9 version of IPM, which was developed in July 2005. In January 2007, EPA prepared new EGU projections (i.e., 3.0 version of IPM). The new EGU projections reflect lower 2018 SO2 emissions for the 3-state region (about 500 TPD less). The MRPO is currently updating its regional modeling inventory to reflect a more current base year (2005) and improved future year emission estimates, including use of the new EGU projections. The new inventory will be available in mid-2007.

Table 4.1-1. Non-EGU Sources Subject to BART in 9-State Region

State	Source Name	County	Source ID	SIC Code
Illinois	Conoco Phillips	Madison	119090AAA	
Illinois	Exxon Mobil	Will	197800AAA	
Illinois	CITGO	Will	197090AAI	
Illinois	National Steel – Granite City	Madison	119813AAI	
Indiana	AGC Division - ALCOA Power Generating	Warrick	2	4911
Indiana	Alcoa Inc. - Warrick	Warrick	7	3334
Indiana	Essroc Cement Corporation (Speed)	Clark	8	3241
Indiana	Essroc Cement Corporation (Logansport)	Cass	5	3241
Indiana	GE Plastics, Mt. Vernon Inc.	Posey	2	2821
Indiana	ISG-Burns Harbor (Formerly Beth. Steel)	Porter	1	3312
Michigan	Lafarge Midwest Inc.	Alpena	B1477	3241
Michigan	Smurfit Stone Container Corp.	Ontonagon	A5754	2611
Michigan	Tilden Mining Co	Marquette	B4885	1011
Michigan	Empire Iron Mining	Marquette	B1827	1011
Michigan	St. Mary's Cement (CEMEX)	Charlevoix	B1559	
Michigan	New Page Paper (Escanaba)	Delta	A0884	
Minnesota	Ipsat Inland (Mittal)	St. Louis	2713700062	1011
Minnesota	EVTAC-Fairlane (United Taconite)	St. Louis	2713700113	1011
Minnesota	National Steel (USS Keetac)	St. Louis	2713700063	1011
Minnesota	Hibbing Taconite	St. Louis	2713700061	1011
Minnesota	USS Minntac	St. Louis	2713700005	1011
Minnesota	Northshore Mining	Lake	2707500003	1011
N. Dakota	Great River Energy – Coal Creek	McLean	17	4911
N. Dakota	Basin Electric Power – Leland Olds	Mercer	1	4911
N. Dakota	Great River Energy – Stanton	Mercer	4	4911
N. Dakota	Minnkota Power – MR Young	Oliver	1	4911
Ohio	Mead Paper Division	Ross	671010028	2611
Wisconsin	Georgia-Pacific Consumer Products, L.P. (former Fort James Operating Company)	Brown	405032870	2621

4.3 Factor 3 – Energy and Other Impacts

For Factor 3, targeted analyses of energy and other adverse environmental impacts were not available in the various program RIAs. However, for the CAIR program it is expected that implementation of SCR and wet scrubber technology would require additional energy to operate, and produce additional wastewater and solid waste. BART analyses conclude that energy and adverse environmental impacts were manageable.

Environmental benefits were qualitatively discussed in several RIAs. In general, it is expected that any reduction in NO_X or SO_2 emissions will decrease nitrate and sulfate deposition. As a result of the CAIR program, the incidence of acidic lakes is projected to decrease from 10% in 2002 to 6% in 2026. Co-benefits of $PM_{2.5}$ and ozone emission reductions are also expected at full implementation of CAIR and the on-road programs. The non-road program is expected to result in a diesel fuel savings of 350 million gallons per year.

4.4 Factor 4 – Remaining Equipment Life

Factor 4 generally does not apply to on-the-books controls on the sector level. Engine and fuel standards impact on-road vehicles beginning in 2007 and non-road vehicles beginning 2008, and fleet turnover for full implementation of these new standards is expected to be completed by 2030. Available documentation from facilities subject to BART indicate that they will install controls rather than shut down to comply with the regulations. IPM projections for the CAIR program indicate that some EGUs in the Midwest region may be retired before 2018. For example, the VISTAS-2.1.9 of IPM estimates that 26 electric generating units may be retired in the three-state region, and 53 units in the nine-state region.

4.5 Factor 5 – Visibility Impacts

Table 4.5-1 compares overall visibility goals with the impacts from On-the-books controls. The MRPO has carried out regional photochemical modeling with CAMx to quantify the level of visibility improvement associated with on-the-books controls in comparison to the uniform rate of visibility improvement in 2018 (see Table 4-3). Figure 4-1 compares the impacts of On-the-books measures to the glide path. Based on these results, the on-the-books control measures will not achieve sufficient emission reductions to fall below the glide path. In addition, On-the-books controls are less effective in improving visibility at Voyageurs than at the other northern-Midwest Class I areas. This appears to be due to differences in source region culpabilities. In particular, the influence from the major Midwest source regions, especially those with the largest change (decrease) in emissions, decreases with distance, i.e., the most impact occurs at Seney (the closest Class I area) and the least impact occurs at Voyageurs (the farthest Class I area).

Table 4.5-1. Comparison of Overall Visibility Goals in 2018 with Projected Impacts for On-the-Books Controls

Pollutant	Estimated visibility impairment on the 20% worst-visibility days (deciviews)[a]			
	Boundary Waters	Voyageurs	Isle Royale	Seney
Baseline conditions (2000-2004)[a]	19.86	19.48	21.62	24.48
Projected conditions in 2018 with on-the-books controls[b]	18.94	19.18	20.04	22.38
Net change	0.92	0.30	1.58	2.10
Glide path goal for 2018	17.70	17.56	19.21	21.35

[a]The baseline condition values reflect the recent adjustments proposed by the Midwest RPO to include several missing days. The adjusted values are, on average, less than 0.5 deciviews greater than those provided on the IMPROVE website.
[b]Based on CAMx modeling by the MRPO. These modeling analyses used preliminary estimates of the impacts of BART controls, which are generally larger than the impacts estimated in industry BART analyses.

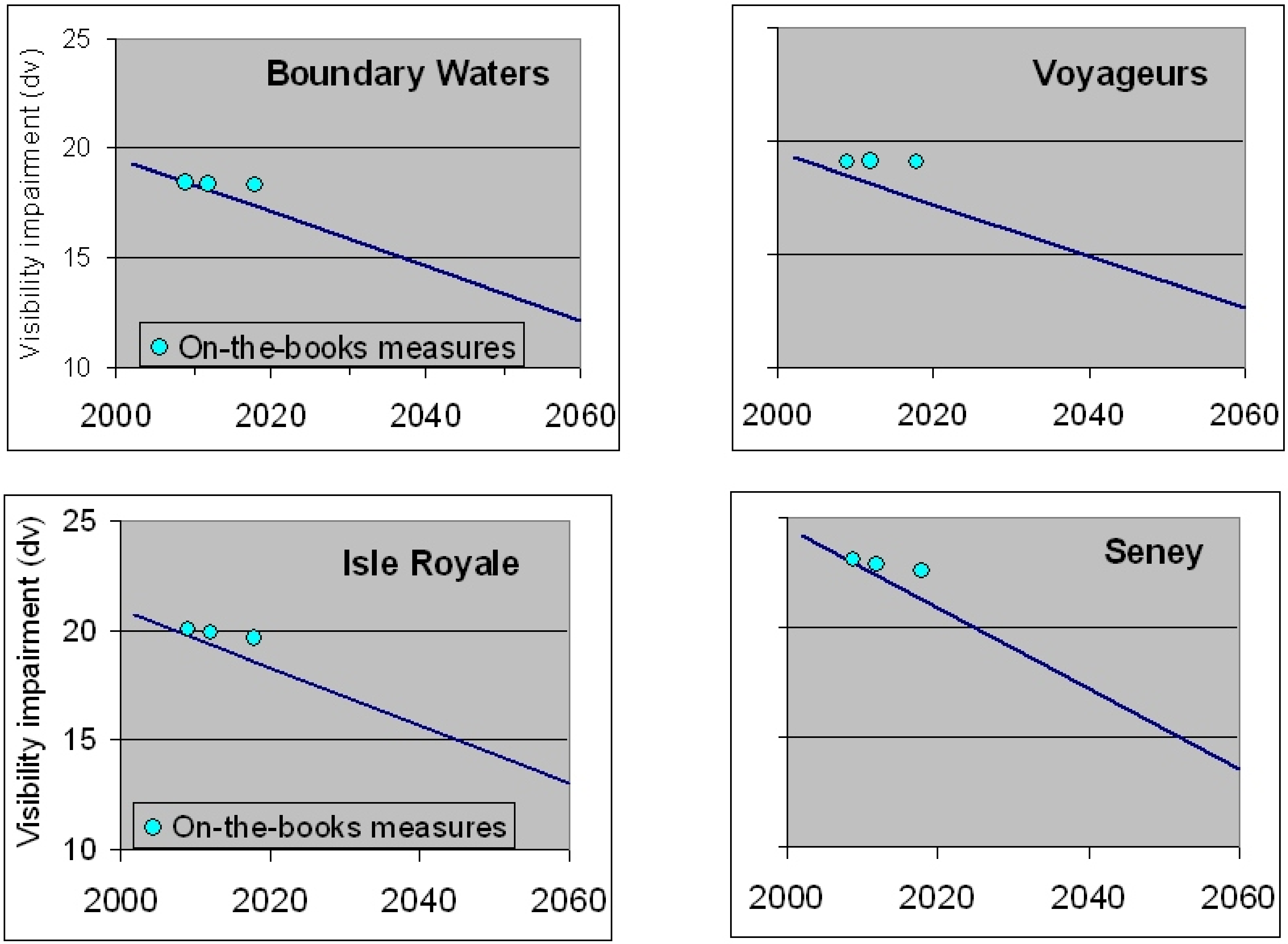

Figure 4-1. Estimated visibility impacts of on-the-books controls in comparison with reasonable progress goals for the northern-Midwest Class I areas

5. Analysis of Potential Additional Control Measures

This section discusses the impacts of several possible control strategies which could be adopted to improve visibility in the northern-Midwest Class I areas. Control strategies for the following emissions and emission source categories have been evaluated:

- SO_2 and NO_X emissions from electric generating units (EGUs)
- SO_2 and NO_X emissions from Industrial, commercial and institutional (ICI) boilers
- Ammonia from agricultural operations
- NO_X emissions from onroad and nonroad mobile sources
- NO_X emissions from reciprocating engines and turbines

These categories were selected in a collaborative process with the Midwest States, based on a review of regional emissions inventories and the results of previous source apportionment modeling studies (as discussed in Section 2). These categories are expected to account for the bulk of SO_2, NO_X and NH_3 emissions in the region in 2018. The control strategies and levels of reductions for these categories were selected in a collaborative process. Taconite facilities were not included in the list of priority source categories, because all eight taconite facilities are subject to BART (six in Minnesota and two in Michigan). A more thorough cost analysis is being performed for BART.

In addition, 20 individual emission facilities were identified by the states for in-depth analysis.[a] These sources are listed in Table 5-1. Most of the individual sources are in the priority emission categories listed above, including 11 EGUs and four facilities with ICI boilers. Two lime manufacturing facilities, one cement plant one petroleum refinery, and one glass furnace were also included in the analysis.

The following subsections present the results of the reasonable progress factor analysis for the selected source categories and individual facilities. A separate subsection is devoted to each emission category, including the selected individual facilities within the category. The final subsection addresses the individual facilities which are not in the selected emission categories.

5.1 Electric Generating Units

The MRPO and the Midwest states have been analyzing potential emission control strategies to reduce SO_2 and NO_X emissions from EGUs. These strategies would establish

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[a]These facilities were selected based on a review of SO_2 and NO_X emissions inventories, emissions v. distance from each of the northern class I areas, and the results of previous source apportionment modeling studies. Facilities were eliminated from consideration if they were subject to BART or have already agreed to new pollution controls. Given time and resource constraints, the evaluation was limited to facilities located in the three northern states.

Table 5-1. Individual Sources Selected for Analysis

State	County	Unit ID	Facility Name	Unit Descriptions
			EGU	
MI	Marquette	B4261	Wisconsin Electric/Presque Isle	
MI	Ottawa	B2835	JH Campbell	
MI	St_Clair	B2796	St. Clair/BelleRiver	
MN	Itasca	2706100004	Clay Boswell	Units 1,2,4 – NOx, SO2
MN	St. Louis	2713700013	Syl Laskin	Units 1,2 – SO2
MN	St. Louis	2713700028	VA PUC	
WI	Buffalo	606034110	Dairyland Power Coop/Alma	
WI	Grant	122014530	Alliant Energy/Nelson Dewey	
WI	Sheboygan	460033090	Alliant Energy/Edgewater	
WI	Ashland	802033320	Xcel Energy/Bayfront	
			Non-EGU	
MI	Alger	B1470	Kimberly Clark	ICI boiler
MI	Schoolcraft	A6475	Manistique Papers	ICI boiler
MI	Monroe	B1743	Holcim	Cement plant
MN	Lake	2707500003	Northshore Mining Company/Silver Bay	EU001 (EGU)
MN	Koochiching	2707100002	Boise Cascade Corp	ICI boiler
WI	Douglas	816009950	Murphy Oil	Refinery (FCCU, Heater)
WI	Lincoln	735008010	PCA - Tomahawk	ICI boilers (B28, B27)
WI	Dunn	617049840	Cardinal FG	Glass Furnace (P01)
WI	Douglas	816036430	CLM Corporation	Lime manuf. (Kilns 2,3,4)
WI	Manitowoc	436034390	Rockwell Lime	Lime manuf. (Kilns 1, 2)

regional caps for SO_2 and NO_X emissions, and would allow trading among the EGUs in the region so that the overall regional emission caps can be attained in the most cost-effective manner. Potential SO_2 and NO_X regional control strategies and unit-level control technologies for EGUs are presented in Appendix B.

Two sets of possible caps have been evaluated, which are termed EGU1 and EGU2:[19]

- EGU1 would establish a regional emissions cap for SO_2 and NO_X based on projected fuel consumption:
  - SO_2 limited to 0.15 pounds per million British thermal units (lb/million-BTU) of fossil fuel consumption in the region
  - NO_X limited to 0.10 lb/million-BTU
- EGU2 would establish regional emission caps for SO_2 and NO_X based on projected fuel consumption:
  - SO_2 limited to 0.10 lb/million-BTU
  - NO_X limited to 0.07 lb/million-BTU

These caps would apply to all fossil fuel power plants rated to produce 25 Megawatts (MW) or more of electricity. The EGU1 caps were selected by the states to correspond roughly to the Best Achievable Control Technology (BACT) levels for retrofit installations. The EGU2 caps were selected to correspond roughly to the BACT levels for new sources.

Previously, these caps have been analyzed as control measures for ambient ozone and $PM_{2.5}$, as well as regional haze. The timeframe considered in these previous analyses was 2009 to 2013, and the geographic area of coverage was the five-state MRPO region. For the current regional haze factor analysis, we used the same numerical caps, but have changed the geographic area of coverage to the three-state and nine-state regions shown in Figure 3-1. In addition, this analysis assumes that the timeframe for implementing the caps would be 2018, the first reasonable further progress target.

Table 5.1-1 shows the projected fuel usage in the three-state and nine-state regions in 2018, projected emissions taking into account on-the-books controls, and estimated allowable emissions with the EGU1 and EGU2 caps. The estimates of fuel usage and baseline emissions in 2018 are based on IPM projections,[a] which have also been used in the analysis of on-the-books control measures (Section 4). These projections take into account the CAIR program, the Acid Rain program, the NO_X SIP call, and other on-the-books controls affecting EGUs. Table 5.1-2 gives estimated baseline emissions at the state level for EGUs in the region in 2002 and 2018. These estimates are based on the LADCO Base K emissions inventory and on IPM projections.

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[a] The EGU projections used in this study are taken from the VISTAS 2.1.9 version of IPM, which was developed in July 2005. In January 2007, EPA prepared new EGU projections (i.e., 3.0 version of IPM). The new EGU projections reflect lower 2018 SO_2 emissions for the 3-state region (about 500 tons/day less). The MRPO is currently updating its regional modeling inventory to reflect a more current base year (2005) and improved future year emission estimates, including use of the new EGU projections. The new inventory will be available in mid-2007.

Table 5.1-1. Estimated Allowable Emissions Under the EGU1 and EGU2 Control Strategies

	3-state region	9-state region
Projected baseline in 2018		
Fossil fuel consumption (trillion BTU)	2,338	6,955
Emissions (1000 tons/year)		
SO2	641	1,808
NOX	188	571
Emissions with EGU1 caps (1000 tons/year)		
SO2	175	522
NOX	117	348
Emissions with EGU2 caps (1000 tons/year)		
SO2	117	348
NOX	82	243

Table 5.1-2. Estimated Baseline Emissions from EGUs

	Emissions in 2002 (1000 tons/year)		Projected emissions in 2018 (1000 tons/year)	
	SO2	NOX	SO2	NOX
Michigan	403	164	399	100
Minnesota	116	99	86	42
Wisconsin	220	107	155	46
3-State Subtotal	739	370	641	188
Illinois	478	260	241	73
Indiana	912	303	377	95
Iowa	150	93	147	51
Missouri	305	167	281	78
North Dakota	137	72	109	72
South Dakota	13	16	12	15
9-State Total	2,734	1,280	1,808	571

5.1.1 Factor 1 – Costs

In analyzing the cost of EGU control strategies, we began with the 2006 National Electric Energy System Database (NEEDS)[20] coupled with detailed projection outputs from the IPM model.[21] The NEEDS database contains data on the pollution control equipment currently installed, as well as the electric generating capacity and heat rate for each EGU. IPM projects the total fuel usage for each EGU in 2018, and gives an estimate of where additional control devices will be installed between now and 2018 to meet on-the-books regulations. IPM is a dynamic optimization model which identifies the lowest cost method of complying with air pollution regulations while meeting electric generation requirements. The model analyzes the costs of a number of possible pollution controls, and also the potential for reducing emissions by fuel switching or inter-utility transfers, taking into account transmission bottlenecks, fuel supply constraints and operational constraints.

We drew on control device cost equations used in IPM to estimate the region-wide costs of complying with the EGU1 and EGU2 strategies.[22] (These cost equations are included in Appendix C.) This approach was chosen since the IPM model is commonly used to estimate the costs of large-scale pollution control programs. In addition, recent IPM analyses of the CAIR program have undergone extensive review. The following control options were included:

- For SO_2:
  - Limestone forced oxidation (LSFO) scrubbers
  - Lime spray dryer (LSD) scrubbers
- For NO_X:
  - Selective catalytic reduction (SCR)
  - Selective non-catalytic reduction (SNCR)
  - Low-NO_X burners (LNB) with and without overfire air (OFA) for dry-bottom wall-fired boilers
  - Low-NO_X nozzles with close-coupled and separated overfire air for tangentially-fired boilers

A more exhaustive list of potential control technologies is provided in Appendix B. The options in the above list were selected because, alone or in combination, they are generally of capable of achieving the emission reductions needed under the EGU1 and EGU2 control strategies. (Appendix C gives the efficiencies assumed for the above options in the EGU analysis.)

The IPM control cost equations give the costs of installing and operating these technologies on a particular EGU based on the electric generating capacity of the unit, its boiler heat rate, and its average annual fuel use. Separate equations are used for capital costs, fixed operation and maintenance costs, and variable operation and maintenance costs (depending on fuel usage). We used these equations to estimate the cost of controlling each EGU in the region with each technology. In amortizing capital costs, we used a 7% interest rate, with additional capital charges of 1% per year for insurance, 1% per year for property taxes, and 2% per year for general and administrative charges. After estimating annualized control costs and potential emission reductions for all of the units in the region, we sorted the control options for the different EGUs in order of increasing cost-effectiveness. We then identified the least expensive sets of control technologies for achieving the EGU1 and EGU2 caps in the three-state and nine-state regions, and summed the costs of these controls. This approach was designed to take into account the potential for trading emission credits among sources. However, it must be noted that it does not take into account fuel switching or other secondary impacts. In addition, the cost estimates do not take into account potential constraints that may exist for installing various control technologies at specific facilities. Therefore, the results reflect only an estimate of the costs which would be incurred to attain the EGU1 or EGU2 emission reduction targets.

Table 5.1-3 details the estimated costs of achieving the EGU1 SO_2 emission cap in the three-state and nine-state regions. The table shows the total generating capacity which is expected to require control, the total emission reduction, the installed capital cost, the total annual cost of control (including capital amortization and operating costs), the average cost effectiveness of control technologies, and the estimated range of cost-effectiveness values for facilities in the region. In addition to the total costs and average cost-effectiveness values for achieving the EGU1 SO_2 emission cap the three-state and nine-state regions, Table 5.1-3 also estimates the breakdown of costs among individual states. Table 5.1-4 provides similar cost estimates for achieving the EGU1 NO_X emission cap in the three-state and nine-state regions. Tables 5.1-5 and 5.1-6 estimate the costs of achieving the EGU2 caps for SO_2 and NO_X, respectively.

It should be noted that the EGU1 strategy, as analyzed here, would allow trading of emission credits across state boundaries within the three-state or the nine-state region. Therefore, the state-specific costs in Table 5.1-3 through 5.1-6 only reflect our best estimate of how control costs would be distributed. In addition, as has been noted earlier, these cost estimates were developed using baseline emissions from the VISTAS 2.1.9 version of IPM, which was developed in July 2005. In January 2007, EPA prepared new EGU projections (i.e., 3.0 version of IPM), which would reflect lower baseline emissions in the 3-state region. Thus, annual costs to achieve the EGU1 and EGU2 targets in the 3-state region could be lower than the estimates given in Tables 5.1-3 through 5.1-6. However, since the most cost-effective controls may have already been implemented to achieve the CAIR baseline in the 3-state region, costs per ton of emission reduction to achieve the EGU1 and EGU2 levels could be higher than the estimates given in Tables 5.1-3 through 5.1-6.

Eleven electric generating facilities were selected for more in-depth analyses. Many of these facilities include multiple boilers, so that a total of 35 individual boilers were analyzed. For these plant-specific analyses, we again estimated costs using the IPM cost equations, and also drew on additional data sources. Appendix C gives detailed estimates of capital costs and annualized costs for each individual unit. The individual facility analyses show that control cost estimates for any particular facility can vary by at least a factor of 2. There are a number of reasons for this range of cost estimates. First, all of the costing approaches rely on default assumptions for flue gas conditions, and for retrofit costs and other contingency costs, which may differ from model to model. The cost models also use different inflation factors when updating older cost data, and different scaling factors to calculate costs for various boiler sizes.

Table 5.1-3. Estimated Costs of EGU1 SO2 Controls for the 3-State and 9-State Regions*

	Estimated numbers of boilers needing control		Total capacity controlled	Emission reduction (1000 tons	Capital cost	Total annual	Cost effectiveness ($/ton)	
	LSFO	LSD	(MW)	/year)	($1000)	cost ($1000)	Average	Range
3-State Region								
Michigan	2	37	10,441	335	1,764,626	478,652	1,428	1,000 - 2,700
Minnesota	0	10	593	22	140,119	39,074	1,759	1,400 - 2,600
Wisconsin	0	25	3,762	108	727,136	199,563	1,840	830 - 2,600
Total	2	72	14,796	466	2,631,881	717,289	1,540	830 - 2,700
9-State Region								
Illinois	1	21	5,831	122	1,012,296	271,060	2,220	660 - 2,800
Indiana	6	31	7,737	226	1,468,135	393,705	1,744	600 - 2,900
Iowa	2	13	4,693	108	767,809	204,844	1,893	630 - 2,600
Michigan	2	40	10,599	341	1,816,190	494,297	1,451	1,000 - 2,800
Minnesota	1	15	1,357	42	327,549	94,410	2,254	1,400 - 2,900
Missouri	2	29	9,243	229	1,469,386	399,666	1,744	610 - 2,800
North Dakota	5	4	2,910	90	580,261	145,701	1,617	560 - 2,700
South Dakota	0	2	477	11	77,464	20,801	1,913	1880 - 1,900
Wisconsin	0	26	3,811	110	743,632	204,501	1,856	830 - 2,900
Total	19	181	46,658	1,279	8,262,722	2,228,985	1,743	560 - 2,900

Table 5.1-4. Estimated Costs of EGU1 NOx Controls for the 3-State and 9-State Regions*

	Estimated numbers of boilers needing control		Total capacity controlled	Emission reduction (1000 tons	Capital cost	Total annual	Cost effectiveness ($/ton)	
	SCR	LNB	(MW)	/year)	($1000)	cost ($1000)	Average	Range
3-State Region								
Michigan	7	4	5,675	42	315,643	75,466	1,785	1,100 - 2,700
Minnesota	5	4	3,175	16	115,282	36,673	2,236	520 - 3,400
Wisconsin	8	8	1,763	12	148,964	32,799	2,626	1,700 - 3,400
Total	20	16	10,613	71	579,889	144,938	2,037	520 - 3,400
9-State Region								
Illinois	3	6	3,046	8	83,671	17,512	2,167	1,000 - 2,600
Indiana	9	1	5,531	32	196,829	72,760	2,304	820 - 3,000
Iowa	6	8	4,164	20	120,473	47,061	2,359	1,100 - 3,300
Michigan	7	4	5,675	42	315,643	75,466	1,785	1,100 - 2,700
Minnesota	1	4	3,171	15	62,982	31,038	2,103	520 - 3,200
Missouri	13	2	3,475	25	165,185	46,975	1,904	690 - 3,000
North Dakota	7	0	4,122	59	331,283	70,345	1,198	760 - 3,300
South Dakota	1	0	477	13	53,045	10,038	775	760 - 2,300
Wisconsin	7	8	1,577	11	128,463	28,068	2,536	1,700 - 3,300
Total	54	33	31,238	224	1,457,574	399,263	1,782	520 - 3,300

* These results do not take into account fuel switching or other secondary impacts, or potential constraints that may exist for installing various control technologies at specific facilities. Additionally, the EGU1 strategy, as analyzed here, would allow trading of emission credits across state boundaries within the three-state or the nine-state region. Thus, the results reflect only an estimate of the costs which would be incurred to attain the EGU1 or EGU2 emission reduction targets.

Table 5.1-5. Estimated Costs of EGU2 SO2 Controls for the 3-State and 9-State Regions*

	Estimated numbers of boilers needing control		Total capacity controlled	Emission reduction (1000 tons	Capital cost	Total annual	Cost effectiveness ($/ton)	
	LSFO	LSD	(MW)	/year)	($1000)	cost ($1000)	Average	Range
3-State Region								
Michigan	5	49	11,021	357	2,018,086	553,751	1,552	1,100 - 4,200
Minnesota	2	19	2,620	57	543,859	155,016	2,743	1,400 - 4,400
Wisconsin	0	32	4,245	119	842,255	235,523	1,981	830 - 4,200
Total	7	100	17,886	532	3,404,200	944,290	1,775	830 - 4,400
9-State Region								
Illinois	2	37	9,659	183	1,796,774	466,945	2,557	660 - 4,200
Indiana	13	37	11,545	282	2,223,006	594,395	2,108	600 - 4,300
Iowa	2	25	5,229	122	940,070	253,579	2,074	630 - 4,100
Michigan	5	49	11,021	357	2,018,086	553,751	1,552	1,100 - 4,200
Minnesota	1	19	1,684	48	417,317	118,964	2,466	1,400 - 4,300
Missouri	2	34	9,942	240	1,637,082	441,007	1,835	610 - 4,100
North Dakota	5	6	2,998	93	610,686	154,657	1,668	560 - 3,600
South Dakota	0	2	477	11	77,464	20,801	1,913	1,900 - 1,900
Wisconsin	0	32	4,245	119	842,255	235,523	1,981	830 - 4,200
Total	30	241	56,800	1,455	10,562,740	2,839,622	1,952	560 - 4,300

Table 5.1-6. Estimated Costs of EGU2 NOx Controls for the 3-State and 9-State Regions*

	Estimated numbers of boilers needing control		Total capacity controlled	Emission reduction (1000 tons	Capital cost	Total annual	Cost effectiveness ($/ton)	
	SCR	LNB	(MW)	/year)	($1000)	cost ($1000)	Average	Range
3-State Region								
Michigan	38	0	8,012	60	898,882	164,478	2,734	1,100 - 7,000
Minnesota	25	2	4,045	26	467,345	86,734	3,298	1,700 - 7,000
Wisconsin	30	0	2,642	20	384,069	69,821	3,495	1,800 - 5,900
Total	93	2	14,699	106	1,750,296	321,033	3,016	1,100 - 7,000
9-State Region								
Illinois	21	0	7,779	22	671,404	124,833	5,605	1,500 - 9,700
Indiana	38	0	5,821	46	753,961	138,817	3,036	820 - 8,600
Iowa	37	3	6,043	35	686,966	125,254	3,580	1,100 - 9,100
Michigan	39	0	8,036	60	911,972	166,300	2,754	1,100 - 7,300
Minnesota	29	0	4,045	27	514,675	94,752	3,456	1,700 - 8,200
Missouri	33	0	5,007	37	636,464	117,302	3,162	1,000 - 9,800
North Dakota	15	0	4,129	62	494,697	90,497	1,459	760 - 5,500
South Dakota	2	0	477	13	56,906	10,554	807	760 - 3,000
Wisconsin	40	0	4,173	25	610,076	110,532	4,418	1,800 - 8,600
Total	254	3	45,510	328	5,337,121	978,841	2,984	760 - 9,800

* These results do not take into account fuel switching or other secondary impacts, or potential constraints that may exist for installing various control technologies at specific facilities. Thus, they reflect only an estimate of the costs which would be incurred to attain the EGU1 or EGU2 emission reduction targets.

The analysis in Appendix C does not include other progress factors besides cost (e.g. time required for compliance, energy and other impacts, and remaining equipment life). In addition, these analyses do not represent definitive assessments of what controls would be appropriate for the selected individual facilities.

5.1.2 Factor 2 – Time Required for Compliance

Once a control strategy is selected, up to 2 years will be needed for states to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[23] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[24] In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single EGU boiler. The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple boilers are to be controlled at a single facility. Based on these figures, the total time required for a single facility to comply with one of the SO_2 caps would be 6½ years, in the absence of any constraints on the capacity to produce and install scrubbers. The total time for a single facility to comply with one of the NO_X caps would be about 5½ years.

Some stakeholders have commented that the large number of facilities requiring emission add-on controls under a regional control strategy, coupled with the current requirements under the CAIR program, would create a shortage of skilled laborers to build and install pollution control equipment and required ancillary equipment, such as stacks. EPA analyzed such constraints during the development of the CAIR rule. The Agency determined that the most critical constraint would be the availability of "boilermaker" labor to build and install scrubbers, SCR systems, and SNCR systems required under the rule. Therefore, EPA carried out a separate analysis of boilermaker availability for the CAIR rule.[25] EPA estimated that approximately 0.272 boilermaker-year/MW is required to fabricate and install scrubbers for SO_2, and approximately 0.344 boilermaker-year/MW is required to fabricate and install SCR technology for NO_X.

EPA also estimated that the tightest constraint on available boilermaker labor for the CAIR program will occur prior to the 2010 interim deadline. Because of the 2 years of lead time required to develop regulations to implement a regional EGU strategy and the additional year needed for capital procurement, the boilermaker demands under the EGU1 or EGU2 control strategies would occur after 2010. Based on the boilermaker availability information given in the CAIR analysis, an estimated boilermaker-year/year will be available after 2010 for building and installing pollution control equipment, beyond the equipment being built for Phase II of the CAIR program. This labor supply would be adequate for all of the possible Midwest EGU control strategies, with the exception of the EGU2 caps over the nine-state region. For the EGU2 cap over the nine-state region, we estimate that shortage of boilermaker labor could potentially extend the time required for compliance to 7 years (instead of 6½).

Based on the above figures, any of the EGU control strategies could be fully implemented by 2018. However, none of the strategies could be implemented by 2012.

5.1.3 Factor 3 – Energy and Other Impacts

Scrubbers, SCR systems, and SNCR systems installed under the EGU control strategies would require electricity to operate fans and other ancillary equipment. In addition, steam would be required for some scrubbers and SCR systems. Additional fuel will be consumed at the utilities to produce this electricity and steam, resulting in the generation of additional carbon dioxide (CO_2) emissions. CO_2 is also released in the production of lime for LSD control systems in the SO_2–limestone reaction in LSFO control systems.

We estimated the energy usage for EGU control technologies based on electricity and steam consumption rates given in the CUECost model. The amount of increased CO_2 was estimated based on these increased electricity and steam demands, and on lime and limestone flowrates given in CUECost. Solid waste generation rates and wastewater generation rates were also estimated from the waste and wastewater factors in CUECost. Table 5.1-7 presents the estimated energy usage, waste generation rate, and wastewater generation rate per Megawatt of generating capacity controlled. The factors in Table 5.1-7 were used to estimate category-wide energy, solid waste, and wastewater impacts, which are summarized in Table 5.1-8.

As Table 5.1-8 shows, the electricity and steam required by controls installed to meet SO_2 and NO_X emission caps would be less than 1% of the total electricity and steam production of EGUs in the region. Solid waste disposal and wastewater treatment costs are expected to be less than 5% of the total operating costs of pollution control equipment.

The SO_2 and NO_X controls would have beneficial environmental impacts by reducing acid deposition and nitrogen deposition to water bodies and natural landscapes. Reductions in these gaseous pollutants are designed to reduce formation of fine particles that impair visibility. Such reductions would also result in decreases in the ambient levels of $PM_{2.5}$, with corresponding health benefits. In addition, broad regional reductions in NO_X would result in reductions in background levels of ambient ozone. These reductions in $PM_{2.5}$ and ozone will reduce levels of these pollutants in urban areas, and improve the potential for urban areas in the Midwest and Northeast to attain the National Ambient Air Quality Standards (NAAQS).

The MRPO carried out a previous modeling effort to evaluate the benefits of implementing the EGU1 and EGU2 emission caps over the 5-state MRPO region by 2012. In this study, the CAMx model was used to estimate reductions in ambient levels of $PM_{2.5}$ and ozone as a result of SO_2 and NO_X emission reductions. The EPA Environmental Benefits Mapping and Analysis Program (BenMAP) was used to quantify health benefits. These benefits would occur not just in the region where emissions limitations are implemented, but also in areas downwind of this region. Table 5.1-9 summarizes the estimated benefits of implementing the EGU1 and EGU2 caps in the 5-state MRPO region. The table shows benefits both in the MRPO region, and in the modeling domain as a whole, including downwind areas.

Table 5.1-7. Factors Used to Calculate Energy and Non-Air Environmental Impacts of EGU Control Measures

Pollution control technique and impact produced	Magnitude of impact	Units
LSD		
Sludge	3.7	ton sludge / ton of SO2 reduced
Electricity	7.0	kW / MW generating capacity
CO2 for electricity	1.0	ton CO2 / MW-hr additional electricity needed
CO2 to produce lime	0.69	ton CO2 / ton of SO2 reduced
LSFO		
Sludge	2.8	ton sludge / ton of SO2 reduced
Electricity	20	kW / MW generating capacity
Steam	114	lb steam / MW-hr of electricity produced
Wastewater	3.7	1000 gal / ton SO2 emission reduced
CO2 for electricity	1.0	ton CO2 / MW-hr additional electricity needed
CO2 for steam	0.26	ton CO2 / ton of additional steam needed
CO2 for control reaction	0.69	ton CO2 / ton of SO2 reduced
SCR		
Sludge	0.10	ton sludge / kW-hr or electricity generated
Electricity	3.0	kW / MW generating capacity
Steam	2.1	lb steam / MW-hr of electricity produced
CO2 for electricity	1.0	ton CO2 / MW-hr additional electricity needed
CO2 for steam	0.26	ton CO2 / ton of additional steam needed

Table 5.1-8. Estimated Energy and Non-Air Environmental Impacts of EGU Control Strategies

	Emission reduction (1000 tons/year)	Additional electricity requirements (GW-hrs /year)	Steam requirements (1000 tons/yr)	Solid waste produced (1000 tons/year)	Wastewater produced (million gallons/year)	Additional CO2 emitted (1000 tons/year)
EGU1 Emission Caps						
3-State Region						
SO2	466	706	510	1,323	192	1,059
NOX	71	40	17	1.7	0	42
Total	537	746	526	1,324	192	1,101
9-State Region						
SO2	1,279	2,649	3,462	3,632	1,128	3,651
NOX	224	110	46	4.6	0	115
Total	1,503	2,759	3,508	3,637	1,128	3,766
EGU2 Emission Caps						
3-State Region						
SO2	532	1,106	1,722	1,511	237	1,523
NOX	106	174	73	7.3	0	181
Total	639	1,279	1,795	1,519	237	1,337
9-State Region						
SO2	1,455	3,504	5,439	4,132	1,919	4,666
NOX	328	608	255	25.4	0	636
Total	1,783	4,113	5,695	4,157	1,919	5,301

Table 5.1-9. Estimated Annual Health Benefits of EGU Control Strategies Applied to the 5-State MRPO Region

	EGU1 Control Strategy				EGU2 Control Strategy			
	Benefits in the MRPO region		Total benefits in the MRPO region and downwind regions		Benefits in the MRPO region		Total benefits in the MRPO region and downwind regions	
Health effect	Number of cases avoided	Value of benefit ($1000)	Number of cases avoided	Value of benefit ($1000)	Number of cases avoided	Value of benefit ($1000)	Number of cases avoided	Value of benefit ($1000)
Acute bronchitis	2,700	1,100	5,000	2,100	3,200	1,300	5,900	2,500
Acute myocardial infarction	3,400	270,000	6,100	480,000	3,900	310,000	7,200	560,000
Acute respiratory symptoms	1,223,000	140,000	2,168,000	250,000	1,473,000	170,000	2,589,000	300,000
Asthma exacerbation	73,300	3,700	131,400	6,700	86,200	4,400	154,200	7,900
Chronic bronchitis	1,000	410,000	1,900	770,000	1,200	480,000	2,200	900,000
Emergency room visits for respiratory symptoms	2,100	790	3,400	1,200	2,500	930	4,000	1,400
Hospital admissions for cardiovascular symptoms	600	15,000	1,200	29,000	700	18,000	1,400	34,000
Hospital admissions for respiratory symptoms	1,100	19,000	1,900	32,000	1,400	23,000	2,400	39,000
Lower respiratory symptoms	29,000	540	52,100	960	34,000	630	61,100	1,200
Premature mortality	1,570	10,000,000	3,010	20,000,000	1,860	12,000,000	3,540	23,000,000
School loss days	27,600	2,500	33,500	3,000	45,600	4,100	55,700	5,000
Work loss days	192,600	31,000	348,300	55,000	226,200	36,000	408,600	63,000
Worker productivity loss		960		1,300		1,700		2,300
Total		11,000,000		22,000,000		13,000,000		25,000,000

Source: Stratus benefits study

Notes:

Benefit values have been updated to 2005 dollars.

These estimates are taken from a study of the application of the EGU1 and EGU2 emission caps over a five-State region, including Illinois, Indiana, Michigan, Ohio, and Wisconsin

The 5-state region analyzed in the benefits study included Michigan, Wisconsin, Illinois, Indiana, and Ohio. The estimated SO_2 emission reductions for this region were about 10% greater than the emission reductions estimated for the 9-state region in the current study.[a] The estimated NO_X emission reductions for the 5 region were midway between the emission reduction estimates for the 3-state region and the 9-state region analyzed in the current study.

Although the earlier study is not directly comparable to the current analysis, it provides an indication of the magnitudes of health benefits in comparison to costs. When benefits in the entire modeling domain were considered, the estimated values of these benefits outweighed the projected costs of control by more than a factor of 10 for both the EGU1 and EGU2 strategies. When only benefits in the MRPO were considered, the predicted benefit values exceeded estimated costs by a factor of 6.

5.1.4 Factor 4 – Remaining Equipment Life

In calculating the costs of control, amortization periods were assumed to be 15 years for LSFO and LSD, and 20 years for SCR, SNCR, and low-NO_X combustion modifications. The purpose of the Factor 4 analysis is to evaluate the increases in annualized costs that would occur in cases where the remaining life of the emission source is less than the amortization period for potential control equipment.

It is difficult to quantify the remaining equipment life for EGUs. Many units have been refurbished multiple times. In the Midwest region, more than 150 units are over 60 years old, and some units are more than 80 years old.[20] In addition, since the EGU strategies are market-based caps to be applied to a broad geographic region, it is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to be an important factor for EGUs.

5.1.5 Factor 5 – Visibility Impacts

Table 5.1-10 presents the estimated visibility impacts at the four northern-Midwest Class I areas for the EGU control strategies implemented over the three-state region and the nine-state region. Results are presented separately for the SO_2 and NO_X caps. In addition, visibility impacts are presented in terms of deciviews and in terms of the change in emissions per distance (Q/d).

Table 5.1-11 estimates the cost effectiveness of EGU controls, expressed in terms of cost per visibility improvement. It must be noted that the estimates of visibility improvement are subject to considerable uncertainty. These are based on rollback calculations using the results of PSAT analyses and CAMx sensitivity analysis. These rollback calculations provide a

[a]Predicted emission reductions for the 5-state region outweigh those for the 9-state region for two reasons. First, the earlier study was performed for the year 2012, five years earlier in the implementation of the CAIR rule. Second, emissions from Ohio are large in comparison with the states that replace it in the 9-state region – Iowa, Minnesota, Missouri, North Dakota, and South Dakota.

mechanism for evaluating the relative impacts of different strategies. However, they may over-estimate or under-estimate the impacts of NO_X controls relative to SO_2 controls. More detailed modeling using CAMx or other photochemical models is needed to fully quantify the impact of any given control strategy.

Table 5.1-10. Estimated Visibility Impacts of EGU Control Strategies

Strategy and region	Estimated visibility improvement in 2018 (deciviews)					Reductions in the summations of emission-to-distance ratios (Q/d; tons/yr-mi)*				
	Boundary Waters	Voyageurs	Isle Royale	Seney	Average	Boundary Waters	Voyageurs	Isle Royale	Seney	Average
EGU1 Emission Caps										
3-State Region										
SO2	0.30	0.12	0.44	0.41	0.32	1,383	1,135	1,476	1,755	1,437
NOX	0.07	0.05	0.06	0.04	0.06	302	244	287	309	285
Total	0.38	0.17	0.50	0.45	0.37	1,685	1,378	1,762	2,064	1,723
9-State Region										
SO2	0.77	0.35	0.84	1.01	0.74	2,961	2,661	3,036	3,391	3,012
NOX	0.18	0.24	0.15	0.12	0.17	604	555	565	573	574
Total	0.95	0.59	1.00	1.13	0.92	3,565	3,216	3,601	3,964	3,586
EGU2 Emission Caps										
3-State Region										
SO2	0.46	0.21	0.52	0.46	0.41	1,647	1,385	1,760	2,035	1,707
NOX	0.12	0.08	0.09	0.07	0.09	467	365	431	453	429
Total	0.58	0.29	0.61	0.53	0.50	2,114	1,750	2,191	2,489	2,136
9-State Region										
SO2	0.87	0.40	0.96	1.18	0.85	3,274	2,948	3,432	3,826	3,370
NOX	0.26	0.30	0.23	0.19	0.24	918	819	858	875	867
Total	1.13	0.69	1.18	1.37	1.09	4,192	3,767	4,291	4,701	4,238

*Q/d reflects the summation of the ratios of emissions to distance for individual sources in each region.

Table 5.1-11. Cost Effectiveness of EGU Control Strategies in Terms of Visibility Improvement

Strategy and region	Cost effectiveness per visibility improvement ($million/ deciview)	Cost effectiveness per change in Q/d ($1000-mi/ton)*
EGU1 Emission Caps		
3-State Region		
SO2	2,249	499
NOX	2,585	508
Total	1,581	603
9-State Region		
SO2	2,994	740
NOX	2,332	695
Total	2,177	733
EGU2 Emission Caps		
3-State Region		
SO2	2,281	553
NOX	3,604	748
Total	1,462	592
9-State Region		
SO2	3,336	843
NOX	4,045	1,128
Total	2,578	901

*Q/d reflects the summation of the ratios of emissions to distance for individual sources in each region.

5.2 Industrial, Commercial, and Institutional Boilers

Source apportionment analyses identify SO_2 and NO_X emissions from non-EGU point sources as the second largest contributor to visibility impairment in Boundary Waters, Seney, and Voyageurs, and the third largest contributor to visibility impairment in Isle Royale in 2018.[7] ICI boilers account for a large portion of SO_2 and NO_X emission from non-EGU point sources.

Potential SO_2 and NO_X regional control strategies and unit-level control technologies for coal-, oil-, and gas-fired boilers are presented in Appendix B. From this list, the states identified two market-based control strategies that would reduce ICI boiler SO_2 and NO_X emissions beyond on-the-books controls. Both strategies target medium and large boilers (i.e., having a design capacity at least 100 Mmbtu/hr, or emitting at least 100 tons/year of either NO_X or SO_2). Coal-fired boilers were examined in particular, as they are estimated to contribute the largest fraction of SO_2 and NO_X boiler state-wide emissions in 2018.

The first strategy was adopted from *Candidate Measure ID ICI1* in the ICI boiler white paper,[26] and requires a 40% SO_2 reduction and a 60% NO_X reduction from 2018 baseline emissions. Similar to EGU1, this strategy was previously analyzed for the 5-state MRPO region with compliance timelines of 2009 and 2013. For this analysis, we have re-defined the compliance timeline to 2018 and the geographic region to the states identified in Figure 3-1.

The second strategy (referred to as the ICI Workgroup Strategy) was prepared by the MRPO's Strategy Workgroup and identifies specific SO_2 and NO_X emissions limitations as a function of boiler type and size, and fuel type (see Table 5.2-3). This strategy provides approximately a 77% reduction in SO_2 emissions and a 70% reduction in NO_X emissions.

To achieve these reductions, the following control technologies were analyzed:

- For SO_2:
  - Spray-dry absorbers (SDA) (90% control)
  - Fuel switching for oil-fired boilers
- For NO_X:
  - SCR for coal-fired boilers (80% control)
  - LNB with OFA and Gas Reburn (80% control) for gas-fired boilers
  - SCR (80% control) for oil-fired boilers

Table 5.2-1 provides a comparison of 2002 and 2018 SO_2 baseline emissions for ICI boilers from area and point sources. The table also presents the contribution of medium and large boilers to the overall ICI boiler inventory, along with a comparison of emissions under the proposed emission reduction strategies. Table 5.2-2 gives a similar summary for NO_X. ICI emissions from point sources contribute 63% of total SO_2 ICI emissions, and 57% of total NO_X ICI emissions in the 9-state region.

Figure 5.2-1 presents a comparison of emissions under the proposed reduction strategies. Figure 5.2-2 shows the fraction of point source emissions from medium and large boilers by fuel type for Illinois, Indiana, Michigan, Minnesota, and Wisconsin. Figure 5.2-2 indicates that the majority of point source emissions can be attributed to solid fuel-fired medium and large boilers.

Table 5.2-1. Estimated Point and Area Source SO2 Emissions from ICI Boilers

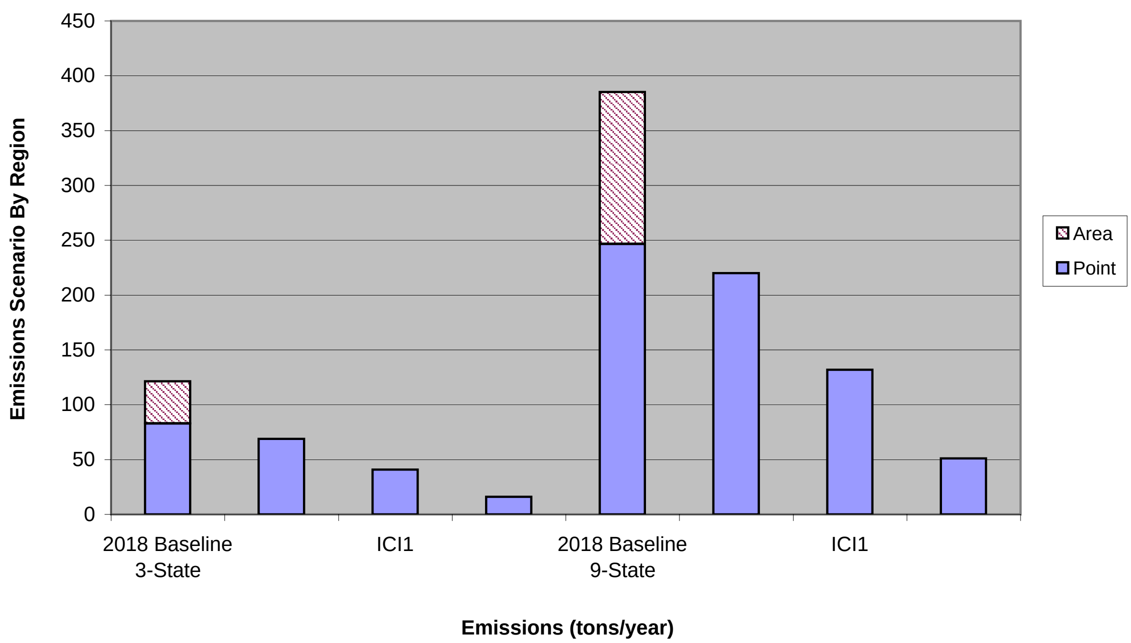
	SO2 emissions from ICI sources in 2002 (1000 tons/year) [a]	Projected SO2 emissions from ICI sources in 2018 (1000 tons/year) [a]	Fraction of ICI SO2 emissions from ICI point sources	Projected SO2 2018 Baseline (Boilers > 100 MmBtu/Hr)	Estimated Allowable Emissions Under ICI1	Estimated Allowable Emissions Under ICI Workgroup
Michigan	44.2	42.8	44%			
Minnesota	20.2	19.7	40%			
Wisconsin	57.0	54.8	95%			
3-State Subtotal	**121.5**	**117.2**	**67%**	**69**	**41**	**16**
Illinois	58.9	59.0	96%			
Indiana	108.9	105.2	48%			
Iowa	32.2	30.6	100%			
Missouri	53.0	52.5	19%			
North Dakota	7.6	7.2	not avail.			
South Dakota	0.7	0.7	not avail.			
9-State Total	**382.8**	**372.3**	**63%**	**220**	**132**	**51**

Table 5.2-2. Estimated Point and Area Source NOX Emissions from ICI Boilers

	NOX emissions from ICI sources in 2002 (1000 tons/year) [a]	Projected NOX emissions from ICI sources in 2018 (1000 tons/year) [a]	Fraction of ICI NOX emissions from ICI point sources	Projected NOX 2018 Baseline (Boilers > 100 MmBtu/Hr)	Estimated Allowable Emissions Under ICI1	Estimated Allowable Emissions Under ICI Workgroup
Michigan	27.0	26.5	60%			
Minnesota	52.9	52.7	18%			
Wisconsin	34.5	33.9	68%			
3-State Subtotal	**114.4**	**113.1**	**43%**	**37**	**15**	**11**
Illinois	49.5	48.0	73%			
Indiana	54.2	52.5	69%			
Iowa	16.3	16.2	100%			
Missouri	18.8	18.7	23%			
North Dakota	5.1	5.1	not avail.			
South Dakota	0.3	0.3	not avail.			
9-State Total	**258.7**	**253.9**	**57%**	**122**	**49**	**36**

[a] Includes emissions from all boiler sizes (< 50 MMBTU/Hr to > 250 MMBTU/HR)

Figure 5.2-1. Projected SO2 Emissions From ICI Boilers



Projected NOX Emissions From ICI Boilers

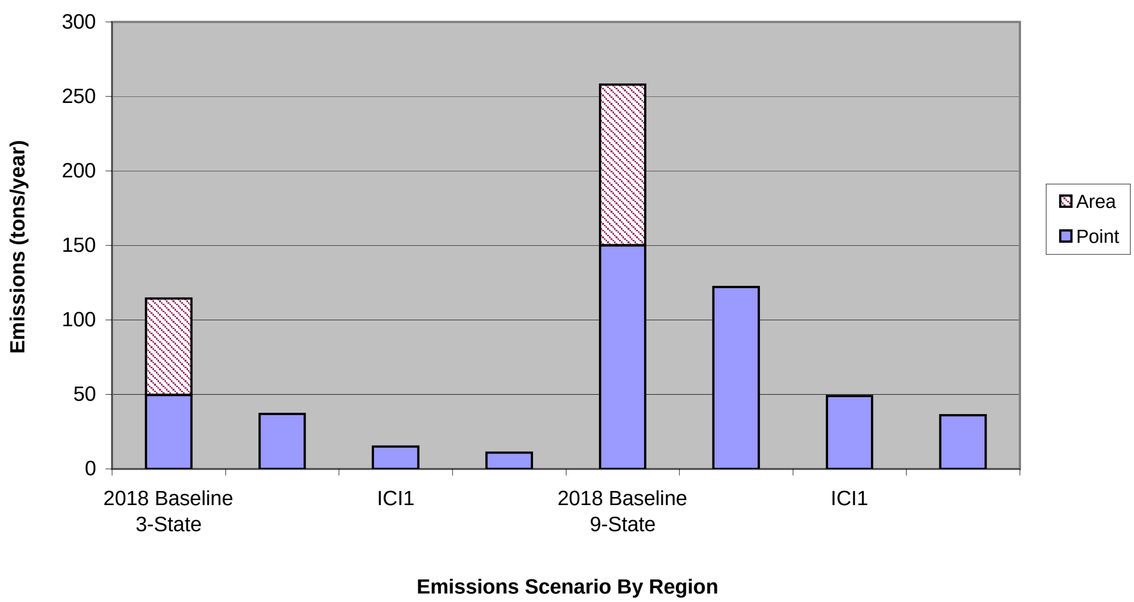
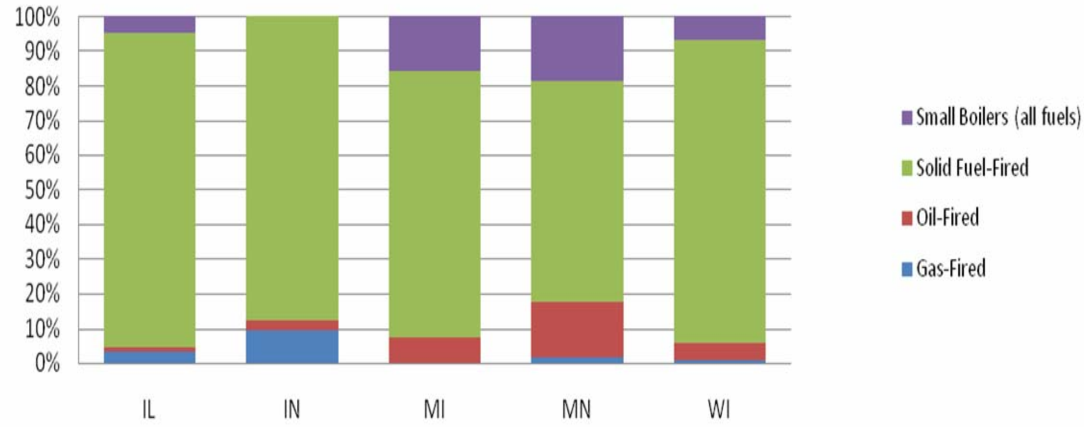
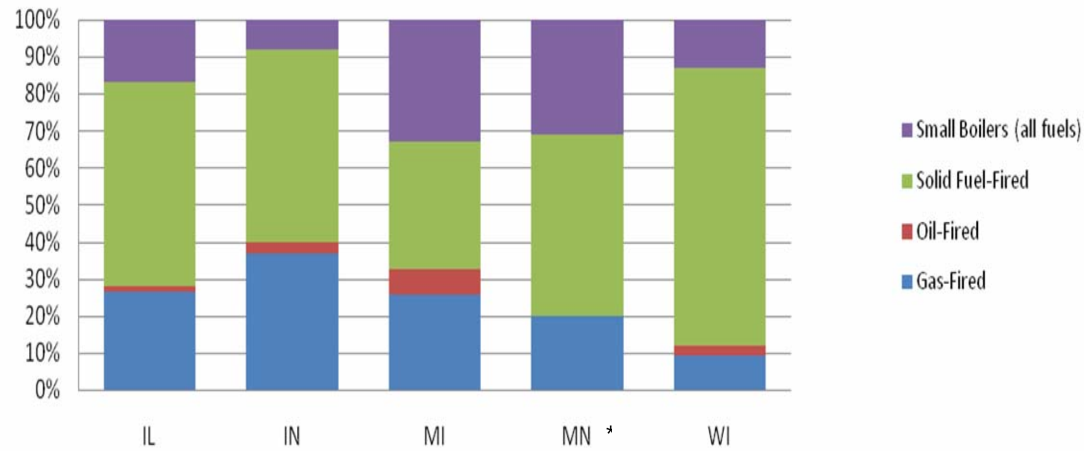


Figure 5.2-2. Fraction of Medium and Large Boiler SO2 Emissions by Fuel Type



Fraction of Medium and Large Boiler NOX Emissions by Fuel Type



*Note: While NOX emissions from medium and large boilers in Minnesota are predominately from solid fuel-fired boilers, emissions from small boilers are predominately from gas-fired boilers. Cumulatively, gas-fired NOX emissions predominate in Minnesota.

Table 5.2-3. ICI Workgroup Proposed Emission Caps

Boiler and Fuel Type	Suggested Limit (lb/MMBTU) <50 million-btu/hr	50-100 million-btu/hr	100 - 250 million-btu/hr	>250 million-btu/hr
Proposed NOx Emission Targets				
Natural Gas and other gaseous fuels		Combustion tuning	0.06	0.06
Fuel Oil (#2 – distillate)		"	0.10	0.10
Fuel Oil (#6 – residual)		"	0.20	0.20
Coal-Wall		"	0.14	0.14
Coal-Tangential		"	0.12	0.12
Coal-Stoker		"	0.22	0.22
Coal-FBC		"	0.08	0.08
Wood/Non-Fossil solid Fuel		"	0.22	0.22
Proposed SO2 Emission Targets				
Distillate Oil (#1, #2)		0.05% sulfur by weight		
Residual Oil (#4, #5, #6)		0.5% sulfur by weight		
Coal (and other solid fuels)		2.0 or 30%	1.2 or 85%	0.25 or 85%

Table 5.2-4. Average Growth Factors for the MRPO Region

Fuel	Growth Factor
NOX	
Gas-fired	1.02
Oil-fired	1.01
Solid fuel	1.01
Coal	0.93
SO2	
Gas-fired	1.02
Oil-fired	0.97
Solid fuel	0.89
Coal	0.93

Baseline emissions for the 9-State region were calculated using the following information:

- Illinois, Indiana, Michigan and Wisconsin 2018 emissions summaries were obtained at the state level by fuel type and categorized into medium and large boiler sizes using percentages from 2002 emission summaries obtained from LADCO.[27] Total emission units were scaled to 2018 units using average growthfactors from the MRPO inventory.[28]
- Minnesota Pollution Control Agency provided 2002 unit-level emissions, which were scaled to 2018 emissions using average growth factors from the MRPO inventory. Reported throughput was assumed to be 65% of total design capacity.
- Iowa, Missouri, and North and South Dakota unit-level emissions were obtained from the 2002 National Emission Inventory (NEI) and scaled to 2018 emissions using average growth factors from the MRPO inventory. Reported throughput was assumed to be 65% of total design capacity.

Table 5.2-4 shows the average growth and control factors used to scale 2002 emissions to 2018.

5.2.1 Factor 1 – Costs

In analyzing costs for retrofit technology (e.g., SDA, SCR, and LNB/OFA/GR), we developed cost curves using the SO_2 and NO_X control cost methodology developed by EPA for industrial boilers.[29,30] This approach was chosen because it provided the most detailed cost analysis for ICI boilers, and has been used in other cost analyses. The IPM approach used for EGUs was not used here because it applies to larger boiler sizes. The EPA ICI boiler cost documentation provides design parameters, economic factors, and initial investment for the control technologies under analysis. Initial capital investment was scaled to 2005 dollars using the Chemical Engineering Index. Fuel and energy costs were obtained in 2005 dollars from the Energy Information Administration (EIA), and operator costs were obtained from the Bureau of Labor and Statistics. Other economic factors (e.g., solid waste disposal, energy, catalyst) were obtained in 2005 dollars from CUECost. The NACAA menu of control options was also used as a point of comparison for cost estimates. This document gives estimates of potential control cost effectiveness for broad ranges of boiler sizes.[6]

In analyzing costs for fuel switching in oil-fired boilers, we obtained fuel cost information from the NACAA document.[6] The incremental annual fuel cost of switching from high to low sulfur fuel was calculated based on the price per million Btu of distillate and residual oil. We did not attempt to calculate the costs of any equipment changes that may be necessary to switch from high to low sulfur oil. The SCC codes reported in the emission inventories indicate that the majority of SO_2 emissions come from residual oil-fired boilers, with the exception of Indiana.

Table 5.2-5 details the estimated costs of achieving the ICI1 SO_2 emission cap in the three-state and nine-state regions. The table shows the total emission reduction, the installed capital cost, the total annual cost of control (including capital amortization and operating costs), the average cost effectiveness of control technologies, and the estimated range of cost-effectiveness values for facilities in the region. We did not attempt to estimate the total boiler capacity controlled due to insufficient information in the inventories. Table 5.2-6 provides similar cost estimates for achieving the ICI1 NO_X emission cap in the three-state and nine-state regions. Tables 5.2-7 and 5.2-8 estimate the costs of achieving the ICI Workgroup caps for SO_2 and NO_X, respectively.

The ICI1 Strategy for SO_2 emissions can be achieved in the 3-State and 9-State region by controlling coal-fired boilers with SDA and oil-fired boilers with fuel switching to a lower sulfur fuel. The strategy for NO_X emissions can be achieved by controlling coal- and oil-fired boilers with SCR, and gas-fired boilers with LNB/OFA/GR. In the 3-State region, cost effectiveness ranges between \$1,944 - \$3,021 per ton of SO_2 reduced and \$1,149 - \$5,478 per ton of NO_X reduced. In the 9-State region, cost effectiveness ranges between \$1,194 - \$2,696 per ton of SO_2 reduced, and \$699 - \$3,911 per ton of NO_X reduced. The NO_X ranges fall within cost-effectiveness ranges reported in the NACAA report.[6]

The ICI Workgroup Strategy for SO_2 emissions can be achieved by controlling coal-fired boilers with SDA and oil-fired boilers with fuel switching to a lower sulfur fuel. The strategy for NO_X emissions can be achieved by controlling coal- and oil-fired boilers with SCR, and gas-fired boilers with LNB/OFA/GR. In the 3-State region, cost effectiveness ranges between \$1,944 - \$6,584 per ton of SO_2 reduced, and \$1,149 - \$9,250 per ton of NO_X reduced. In the 9-State region, cost effectiveness ranges between \$1,194 - \$9,403 per ton of SO_2 reduced and \$699 - \$5,488 per ton of NO_X reduced. These values are above the ranges given in the NACAA report, in terms of the cost per ton of emission reduction. This is because our projections indicate that this strategy may require control of smaller emission sources, which are outside of the boiler size ranges analyzed in the NACAA report.

Individual facility analyses used the same EPA cost equations derived for the sector-level analysis, and also drew on a number of additional data sources (similar to the EGU analyses). However, the ICI facility analyses omit the use of CUECost because the model is only applicable to units $\geq$ 100 MW. See Appendix C for the results of the individual facility factor analysis. The analysis in Appendix C does not include an analysis for time required for compliance, energy and other impacts, or remaining equipment life. In addition, this analysis does not represent assessments of BART for the selected individual facility.

Table 5.2-5. Estimated Costs of ICI1 SO2 Controls for the 3-State and 9-State Regions

Fuel Type	Control Technology	Potential Emission Reduction (1000 Tons/yr)	Average Capital Costs ($1000)	Average O&M Cost ($1000)	Average Annualized Cost ($1000)	Average Cost-Effectiveness ($/ton)	Cost Effective-ness Range ($/ton)
			3-State Region				
Coal	SDA	32	360,313	42,931	96,904	2,998	
Oil	Fuel Switching	1	--	--	1,459	2,643	
Grand Total		**33**	**360,313**	**42,931**	**98,363**	**2,992**	**1,944 - 3,021**
			9-State Region				
Coal	SDA	93	749,979	98,544	210,887	2,258	
Oil	Fuel Switching	12	--	--	27,800	2,414	
Grand Total		**105**	**749,979**	**98,544**	**238,687**	**2,275**	**1,194 - 2,696**

Table 5.2-6. Estimated Costs of ICI1 NOX Controls for the 3-State and 9-State Regions

Fuel Type	Control Technology	Potential Emission Reduction (1000 Tons/yr)	Average Capital Costs ($1000)	Average O&M Cost ($1000)	Average Annualized Cost ($1000)	Average Cost-Effectiveness ($/ton)	Cost-Effectiveness Range ($/ton)
			3-State Region				
Coal	SCR	19	181,776	21,043	45,472	2,410	
Gas	LNB/OFA/GR	3	48,497	2,408	8,925	2,909	
Oil	SCR	1	11,905	947	2,547	4,992	
Grand Total		**22**	**242,178**	**24,397**	**56,944**	**2,537**	**1,149 - 5,478**
			9-State Region				
Coal	SCR	35	326,145	38,650	82,482	2,358	
Gas-fired	LNB/OFA/GR	27	263,852	12,529	47,989	1,757	
Oil-fired	SCR	11	36,835	3,647	8,598	785	
Grand Total		**73**	**626,833**	**54,827**	**139,068**	**1,899**	**699 - 3,911**

Table 5.2-7. Estimated Costs of ICI Workgroup SO2 Controls for the 3-State and 9-State Regions

Fuel Type	Control Technology	Potential Emission Reduction (1000 Tons/yr)	Average Capital Costs ($1000)	Average O&M Cost ($1000)	Average Annualized Cost ($1000)	Average Cost-Effectiveness ($/ton)	Cost-Effectiveness Range ($/ton)
			3-State Region				
Coal	SDA	50	489,325	61,616	134,915	2,683	
Oil	Fuel Switching	2	--	--	8,579	3,779	
Grand Total		**53**	**489,325**	**61,616**	**143,493**	**2,731**	**1,944 - 6,584**
			9-State Region				
Coal	SDA	145	1,549,160	194,981	427,037	2,953	
Oil	Fuel Switching	24	--	--	35,739	1,482	
Grand Total		**169**	**1,549,160**	**194,981**	**462,776**	**2,743**	**1,194 - 9,403**

Table 5.2-8. Estimated Costs of ICI Workgroup NOX Controls for the 3-State and 9-State Regions

Fuel Type	Control Technology	Potential Emission Reduction (1000 Tons/yr)	Average Capital Costs ($1000)	Average O&M Cost ($1000)	Average Annualized Cost ($1000)	Average Cost-Effectiveness ($/ton)	Cost-Effectiveness Range ($/ton)
			3-State Region				
Coal	SCR	23	352,042	38,183	85,495	3,682	
Gas	LNB/OFA/GR	5	108,523	4,984	19,569	4,103	
Oil	SCR	1	20,180	1,766	4,479	6,144	
Grand Total		**29**	**480,745**	**44,933**	**109,543**	**3,814**	**1,149 - 9,250**
			9-State Region				
Coal	SCR	45	508,902	60,083	128,476	2,879	
Gas	LNB/OFA/GR	29	315,868	14,966	57,417	1,970	
Oil	SCR	11	48,741	4,594	11,145	972	
Grand Total		**85**	**873,511**	**79,643**	**197,038**	**2,311**	**699 - 5,488**

5.2.2 Factor 2 – Time Necessary for Compliance

Similar to the EGU Factor 2 analysis, we estimate that a facility may achieve both ICI1 and the ICI Workgroup SO_2 strategies in six and a half years, in the absence of any constraints on the capacity to produce and install scrubbers. The total time for a single facility to comply with one of the NO_X strategies would be about five and a half years. This estimate is based on the following information:

- Two years for rule development and implementation
- Up to a year for industry to procure the necessary capital to purchase control equipment.
- Eighteen months to design, fabricate, and install SCR or SNCR technology for NO_X control, and approximately 30 months to design, build, and install SO_2 scrubbing technology.
- An additional 12 months for staging the installation process if multiple boilers are to be controlled at a single facility.

5.2.3 Factor 3 – Energy and Other Impacts

Similar to the EGU Factor 3 analysis, we estimated the energy usage for SDA and SCR based on electricity and steam consumption rates given in the CUECost model. The amount of increased CO_2 was estimated based on these increased electricity and steam demands, and on lime and limestone flowrates given in CUECost. Solid waste generation rates and wastewater generation rates were also estimated from the waste and wastewater factors in CUECost. Electricity estimates for LNB/OFA/GR were obtained from the EPA ICI control report.[28, 30, 30]

Table 5.2-9 presents the estimated energy usage, waste generation rate, and wastewater generation rate per ton of pollutant controlled. The factors in Table 5.2-9 were used to estimate category-wide energy, solid waste, and wastewater impacts, which are summarized in Table 5.2-10.

As Table 5.2-10 shows, the electricity and steam required by controls installed to meet SO_2 and NO_X emission caps would be less than 1% of the total electricity and steam production in the region. Solid waste disposal and wastewater treatment costs are expected to be less than 5% of the total operating costs of pollution control equipment.

5.2.4 Factor 4 – Remaining Equipment Life

Similar to EGUs, ICI boilers have no set equipment life. In fact, many units have been refurbished multiple times. Of the boilers reporting installation dates in the Midwest, over 45% are more than 50 years old.[31] In addition, since the ICI strategies are market-based reductions to be applied to a broad geographic region, it is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for ICI boilers.

Table 5.2-9. Factors Used to Calculate Energy and Non-Air Environmental Impacts of ICI Control Measures

Pollution control technique and impact produced	Magnitude of impact	Units
SDA		
Sludge	3.7	ton sludge / ton of SO2 reduced
Electricity	0.4	MW-hr / ton SO2 reduced
CO2 for electricity	1.0	ton CO2 / MW-hr additional electricity needed
CO2 to produce lime from limestone	0.69	ton CO2 / ton of SO2 reduced
SCR		
Sludge	0.021	ton spent catalyst / ton of NOX reduced
Electricity	0.89	MW-hr / ton of NOX removed
Steam	0.25	ton steam / ton of NOX removed
CO2 for electricity	1.0	ton CO2 / MW-hr additional electricity needed
CO2 for steam	0.26	ton CO2 / ton of additional steam needed
LNB/OFA/GR		
Electricity	6.4	MW-hr / ton NOX reduced
CO2 for electricity	1.0	ton CO2 / MW-hr additional electricity needed

Table 5.2-10. Estimated Energy and Non-Air Environmental Impacts of ICI Control Strategies

	Emission reduction (1000 tons/year)	Additional electricity requirements (GW-hrs /year)	Steam require-ments (1000 tons/yr)	Solid waste produced (1000 tons/year)	Additional CO2 emitted (1000 tons/year)
ICI1 Strategy					
3-State Region					
SO2	33	13	-	120	35
NOX	22	37	5	0	38
Total	55	50	5	120	74
9-State Region					
SO2	105	37	-	346	102
NOX	73	214	12	1	217
Total	178	251	12	347	319
ICI Workgroup Strategy					
3-State Region					
SO2	53	20	-	186	55
NOX	29	53	6	1	55
Total	81	73	6	187	110
9-State Region					
SO2	169	58	-	537	158
NOX	85	235	14	1	239
Total	254	293	14	538	397

5.2.5 Factor 5 – Visibility Impacts

Table 5.2-11 presents the estimated visibility impacts at the four northern-Midwest Class I areas for the ICI control strategies implemented over the three-state region and the nine-state region. Results are presented separately for the SO_2 and NO_X reductions.

Table 5.2-12 estimates the cost effectiveness of ICI controls, expressed in terms of cost per visibility improvement. It must be noted that the estimates of visibility improvement are subject to considerable uncertainty. These are based on rollback calculations using the results of PSAT analyses and CAMx sensitivity analysis. These rollback calculations provide a mechanism for evaluating the relative impacts of different strategies. However, they may over-estimate or under-estimate the impacts of NO_X controls relative to SO_2 controls. More detailed modeling using CAMx or other photochemical models is needed to fully quantify the impact of any given control strategy.

Table 5.2-11. Estimated Visibility Impacts of ICI Control Strategies

			Estimated visibility improvement in 2018 (deciviews)				
Strategy	Region	Pollutant	Boundary Waters	Voyageurs	Isle Royale	Seney	Average
ICI1	3-State	SO2	0.07	0.03	0.07	0.05	0.06
		NOX	0.07	0.05	0.03	0.02	0.04
	9-State	SO2	0.09	0.05	0.09	0.11	0.08
		NOX	0.10	0.07	0.05	0.06	0.07
	3-State	SO2	0.10	0.06	0.11	0.09	0.09
ICI Workgroup		NOX	0.10	0.06	0.03	0.03	0.05
	9-State	SO2	0.15	0.08	0.15	0.18	0.14
		NOX	0.11	0.08	0.06	0.07	0.08

Table 5.2-12. Cost Effectiveness of ICI Control Strategies in Terms of Visibility Improvement

	Average cost effectiveness values	
Strategy/Region	per emission reduction ($/ton)	per visibility improvement ($million /dv)
ICI1		
3-State Region		
SO2	2,992	1,776
NOX	2,537	1,327
9-State Region		
SO2	2,275	2,825
NOX	1,899	2,034
ICI Workgroup		
3-State Region		
SO2	2,731	1,618
NOX	3,814	1,993
9-State Region		
SO2	2,743	3,397
NOX	2,311	2,473

5.3 Reciprocating Engines and Turbines

Internal combustion engines at industrial, commercial, and institutional facilities are projected to account for about 22% of NO_X emissions from non-EGU stationary sources in 2018. Reciprocating engines represent the largest share of this figure, at about 17%, with the remaining 5% attributed to turbines. Table 5.3-1 shows estimated emissions for reciprocating engines in turbines in 2002, and projected emissions in 2018. The emissions estimates for MRPO states – Michigan, Wisconsin, Illinois, and Indiana – are taken from the MRPO Base K 2002 emissions inventory and the MRPO Base K/Round 4 Strategy Modeling Inventory for 2018. Emissions estimates for Minnesota, Iowa, Missouri, North Dakota, and South Dakota in 2002 were taken from the National Emissions Inventory. Emissions in 2018 were estimated assuming growth rates similar to those projected for the MRPO states.

An update to EPA's Alternative Control Techniques (ACT) guidance for reciprocating engines identifies a Low-Emission Combustion (LEC) retrofit technology which can reduce emissions from these sources by an average of 89%.[32] LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). AirControlNET also identifies a number of combustion modification measures to reduce NO_X emissions from reciprocating engines and turbines. Ignition retarding technologies are estimated to reduce emissions from reciprocating engines by 25%.[33] Water injection or steam injection can reduce emissions from turbines by 68 to 80%, and low-NO_X burners can reduce turbine emissions by 84%. In addition, SCR can be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by over 90%.

The NEI indicates that over half of the non-EGU internal combustion sources in the stationary source inventory emit less than 1 ton/year; however, almost 75% of emissions emanate from engines or turbines emitting 100 or more tons/year. Over 95% of emissions are from sources emitting 10 or more ton/year.

We have evaluated two strategies for this category. The first would affect reciprocating engines and turbines emitting 100 tons/year or more, and the second would affect sources emitting 10 tons/year or more. Both strategies would reduce the emissions from affected reciprocating engines by 89% and from affected turbines by 84%. These emission reduction levels were selected because they can be achieved by either low-NO_X combustion technology or by SCR.

Table 5.3-2 estimates the potential emission reduction impacts of these two control strategies for states in the region. The table gives the estimated emissions in each state above the size cutoffs of 100 tons/year and 10 tons/year. These are the emissions that would be covered by the two potential control strategies. The affected fractions were estimated based on state-specific distributions of emission source sizes from the NEI. Table 5.3-2 then estimates potential emission reductions based on emission reductions of 89% for reciprocating engines and 84% for turbines. These estimates represent reductions beyond the levels of control expected from on-the-books measures. (MRPO strategy modeling estimates reductions of 8 to 15% for reciprocating engines in different states.)

Table 5.3-1. Estimated Emissions from Reciprocating Engines and Turbines in Relation to Total Non-EGU Emissions in 2018

	NOX emissions from stationary internal combustion sources in 2002 (tons/day)*			Projected NOX emissions from stationary internal combustion sources in 2018 (tons/day)*			Projected NOX emissions from all non-EGU point sources (tons/day)	Stationary internal combustion as a fraction of all non-EGU point sources in 2018 (%)
	Reciprocating engines	Turbines	Total	Reciprocating engines	Turbines	Total		
Michigan	44.1	11.4	55.5	41.4	11.5	52.9	229.3	23.1
Minnesota	18.3	5.9	24.3	17.6	6.3	23.9	182.6	13.1
Wisconsin	8.1	1.9	10.0	7.2	1.9	9.2	93.8	9.8
3-State Subtotal	70.5	19.2	89.8	66.2	19.7	85.9	505.7	17.0
Illinois	112.5	14.3	126.8	110.6	15.9	126.4	342.7	36.9
Indiana	25.1	1.7	26.8	23.0	1.8	24.7	225.4	11.0
Iowa	26.3	1.6	27.9	25.2	1.7	26.9	121.7	22.1
Missouri	21.0	3.2	24.3	20.2	3.4	23.6	111.2	21.2
North Dakota	8.7	1.3	10.0	8.3	1.4	9.7	36.1	26.9
South Dakota	0.0	1.0	1.0	0.0	1.1	1.1	24.0	4.6
9-State Total	264.1	42.5	306.6	253.6	44.9	298.4	1,366.9	21.8

*Excludes reciprocating engines and turbines classified as EGUs.

Table 5.3-2. Potential Emission Reductions for Candidate Internal Combustion Control Measures

Size cutoff and state	Estimated emissions covered in 2018 (tons/day)		Potential emission reductions from on-the-books levels (tons/day)		
	Reciprocating engines	Turbines	Reciprocating engines	Turbines	Total
100 tons/year or more					
Michigan	8.2	9.4	7.1	7.9	15.0
Minnesota	11.6	3.6	10.3	3.1	13.4
Wisconsin	5.3	1.2	4.6	1.0	5.6
Subtotal for 3-State region	25.0	14.2	22.0	11.9	34.0
Illinois	93.6	6.6	82.3	5.6	87.9
Indiana	16.5	0.9	14.7	0.7	15.4
Iowa	16.5	0.0	14.7	0.0	14.7
Missouri	12.7	0.0	11.3	0.0	11.3
North Dakota	8.2	1.4	7.3	1.2	8.5
South Dakota	0.0	1.1	0.0	0.9	0.9
Total for 9-State region	172.6	24.2	152.4	20.3	172.7
10 tons/year or more					
Michigan	38.4	11.4	33.6	9.6	43.1
Minnesota	15.6	6.1	13.9	5.1	19.1
Wisconsin	6.5	1.8	5.7	1.5	7.2
Subtotal for 3-State region	60.6	19.2	53.2	16.2	69.4
Illinois	108.7	14.3	95.6	12.0	107.6
Indiana	22.3	1.3	19.6	1.1	20.7
Iowa	24.4	1.0	21.7	0.8	22.5
Missouri	19.1	2.7	17.0	2.2	19.2
North Dakota	8.3	1.4	7.4	1.2	8.6
South Dakota	0.0	1.1	0.0	0.9	0.9
Total for 9-State region	243.4	40.9	214.5	34.4	248.9

5.3.1 Factor 1 – Costs

EPA's updated ACT guidance for reciprocating engines estimates the cost estimates of installing Low Emission Combustion technology on existing engines of various sizes (based on their brake-horsepower rating).[32] The 100 ton/year emission cutoff level is estimated to correspond to an engine size of about 800 brake-horsepower, for which the cost-effectiveness of would be about \$980/ton of NO_X emission reduction (in 2005 dollars). The cost-effectiveness at the 10 ton/year emission cutoff level (about 80 brake-horsepower) is estimated to be about \$8,200/ton.

AirControlNET estimates that low-NO_X burner technology can be installed on emission sources larger than 34 million BTU with a cost-effectiveness of about \$750/ton of NO_X emission reduction.[33] This turbine size corresponds to an uncontrolled emission rate of about 40 tons/year. At the 10 ton/year emission cutoff, we have estimated a cost effectiveness of about \$1,600/ton, based on scaling factors used in AirControlNET for similar sources.

Table 5.3-3 gives estimated average cost-effectiveness values and cost-effectiveness ranges for the internal combustion control strategies. The average cost effectiveness values were calculated using emission engine and turbine size distributions from the NEI. These cost-effectiveness values are based on the modification of engines and turbines to use low-NO_X combustion technologies. SCR systems could also be used attain the candidate emission reduction targets, however these systems are expected to be less cost-effective than low-NO_X combustion modifications.

5.3.2 Factor 2 – Time Necessary for Compliance

Based on information developed for the EGU and ICI emission source categories, we have estimated the time required for compliance with internal combustion control strategies at between 5½ and 6½ years. This estimate includes the following components:

- 2 years for states to develop the necessary rules to implement the strategy
- Up to 1 year to procure the necessary capital to modify burners or purchase control equipment
- 18 to 30 months required to make burner modifications or install control technology for a single engine or turbine
- An additional 12 months for staging the installation process if multiple sources are to be controlled at a single facility.

5.3.3 Factor 3 – Energy and Other Impacts

Low-NO_X combustion technologies are expected to be the most cost-effective methods for achieving the candidate emission reduction targets for both reciprocating engines and turbines. Some low-NO_X combustion technologies require electricity for turbocharging or steam for steam injection. However, the candidate emission limits are based on systems which require only modifications to alter fuel-air mixing and combustion temperatures.[32,33] These changes are not expected to produce any additional electricity or steam demands, or generate wastewater or solid waste.

Table 5.3-3. Estimated Cost Effectiveness of Controls for Internal Combustion Sources

Sources covered	Cost effectiveness ($/ton of NOX emission reduction) Average	Range
Control of sources emitting over 100 tons/year		
3-State region		
Reciprocating engines	538	310 - 980
Turbines	754	750 - 750
Total	614	310 - 980
9-State region		
Reciprocating engines	506	240 - 980
Turbines	754	750 - 750
Total	535	240 - 980
Control of sources emitting over 10 tons/year		
3-State region		
Reciprocating engines	1,286	310 - 8,200
Turbines	800	750 - 1,600
Total	1,172	310 - 8,200
9-State region		
Reciprocating engines	1,023	240 - 8,200
Turbines	819	750 - 1,600
Total	995	240 - 8,200

NO_X emission reductions from reciprocating engines and turbines would have beneficial environmental impacts by reducing acid deposition and nitrogen deposition to water bodies and natural landscapes. Regional haze control strategies for NO_X are designed to reduce formation of fine particles that impair visibility. Such reductions would also result in decreases in the ambient levels of $PM_{2.5}$, with corresponding health benefits. In addition, broad regional reductions in NO_X would result in reductions in background levels of ambient ozone. These reductions in $PM_{2.5}$ and ozone could improve the potential for urban areas in the Midwest to attain the NAAQS for these pollutants.

5.3.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of reciprocating engines and turbines in the Midwest region. Older equipment may not be amenable to low-NO_X combustion modifications. For these sources, the candidate emission reduction targets could be achieved with SCR; however, costs would be up to 3.5 times the estimated cost of low-NO_X combustion modifications.[33] In addition, if the remaining equipment life is less than the 15 year amortization period for an SCR system, the annual cost of control would be further increased. The combined impact of these factors could increase the cost-effectiveness to $10,000 per ton for older engines.

5.3.5 Factor 5 – Visibility Impacts

Table 5.3-4 presents the estimated visibility impacts at the four northern-Midwest Class I areas for the internal combustion control strategies implemented over the three-state region and the nine-state region. Table 5.3-5 estimates the cost effectiveness of the candidate internal combustion control measures in terms of cost per visibility improvement.

It must be noted that the estimates of visibility improvement are subject to considerable uncertainty. These are based on rollback calculations using the results of PSAT analyses and CAMx sensitivity analysis. These rollback calculations provide a mechanism for evaluating the relative impacts of different strategies. However, they may over-estimate or under-estimate the impacts of NO_X controls relative to SO_2 controls. More detailed modeling using CAMx or other photochemical models is needed to fully quantify the impact of any given control strategy.

Table 5.3-4. Estimated Visibility Improvements from Internal Combustion Control Measures

Region	Estimated visibility improvement in 2018 (deciviews)				
	Boundary Waters	Voya-geurs	Isle Royale	Seney	Average
Control of sources emitting over 100 tons/year					
3-State region					
Reciprocating engines	0.027	0.017	0.009	0.008	0.015
Turbines	0.014	0.009	0.005	0.005	0.008
Total	0.041	0.026	0.015	0.013	0.024
9-State region					
Reciprocating engines	0.074	0.053	0.036	0.044	0.052
Turbines	0.010	0.007	0.005	0.006	0.007
Total	0.084	0.060	0.041	0.050	0.059
Control of sources emitting over 10 tons/year					
3-State region					
Reciprocating engines	0.064	0.041	0.023	0.020	0.037
Turbines	0.019	0.013	0.007	0.006	0.011
Total	0.084	0.054	0.030	0.026	0.048
9-State region					
Reciprocating engines	0.105	0.075	0.051	0.062	0.073
Turbines	0.017	0.012	0.008	0.010	0.012
Total	0.121	0.087	0.059	0.072	0.085

Table 5.3-5. Cost Effectiveness of Internal Combustion Control Strategies in Terms of Visibility Improvement

Strategy and region	Cost effectiveness per visibility improvement ($million/ deciview)
Control of sources emitting over 100 tons/year	
3-State region	
Reciprocating engines	282
Turbines	395
Total	677
9-State region	
Reciprocating engines	542
Turbines	810
Total	1,352
Control of sources emitting over 10 tons/year	
3-State region	
Reciprocating engines	673
Turbines	419
Total	1,092
9-State region	
Reciprocating engines	1,095
Turbines	880
Total	1,975

5.4 Ammonia Emissions from Agricultural Sources

Agricultural sources account for an estimated 99% of ammonia emissions in the three-state region, and 97% in the nine-state region. The bulk of these emissions are from livestock; while a smaller portion, about 5%, results from the use of synthetic nitrogen fertilizers. Ammonia emissions from livestock emanate from urea and other nitrogen compounds in their waste. Microbes convert the urea to ammonium compounds, which can then produce ammonia emissions at a number of different points within the farm. These include animal houses, waste collection and storage systems, waste treatment systems, pastures, and fields on which the waste is used.

The most widely used synthetic nitrogen fertilizer is anhydrous ammonia, which is injected into the soil in gaseous form. Other nitrogen fertilizers include synthetic urea, ammonium compounds, and nitrate compounds, all of which can be used in solid form or in solutions. Ammonia, urea, and ammonium fertilizers give off ammonia gas after they are applied to crops.

States have identified Best Management Practices (BMPs) for the management of animal waste and for the use of nitrogen fertilizers. These practices are designed to reduce water pollution and groundwater pollution impacts, but many BMPs also act to mitigate ammonia emissions. BMPs in the Midwest states include the following.

- For animal houses and waste collection systems:
  - Conveyor belts for removal of waste
  - Daily scrape and haul of manure
  - Transfer pipes to transfer manure to storage or treatment structure
  - Leaving manure to mix with bedding to form manure pack
  - Hopper to transfer manure
  - Outdoor housing of cattle (outwintering)
- For manure storage systems:
  - Stockpiling manure in one area
  - Deep pits to store manure
  - Treatment of waste in lagoons
  - Walled storage facilities or storage tanks
  - Covered storage facilities
- For application of manure to crop lands and grasslands:
  - Incorporation of manure into the soil after apreading
  - Injection of manure using sweeps or knives
  - For general manure management:
  - Planning for manure management
  - Solid-liquid manure separating system
  - Composting of manure

- For nitrogen fertilizer usage:
  - Reduction nitrogen fertilizer usage – through the use of realistic crop yield goals when calculating fertilizer needs, improved recordkeeping, and soil nitrogen tests
  - Adjusting the timing of fertilizer application to meet crop needs
  - Maintaining optimal soil pH
  - Injection or incorporation of fertilizer into the soil
  - Crop rotation and and use of nitrogen-fixing crops in place of nitrogen fertilizer

Other techniques have also been evaluated for controlling ammonia emissions. Feed adjustments have been proposed which would reduce the amount of nitrogen compounds excreted by farm animals. This is generally done by improving the mix of amino acids eaten by the animal, reducing the animal's consumption of crude protein, and matching the animal's protein consumption to its needs during different stages of growth. Researchers have also evaluated use of trees to absorb ammonia emissions. These trees would be planted near the ventilation systems of animal houses, or as a buffer around other ammonia emission sources.

Some researchers have proposed the use of additives such as alum to reduce emissions from animal waste. In addition, research has been performed on the use of urease inhibitors to delay the conversion of urea to ammonia. The purpose of this control measure is to allow crops to more effectively absorb nitrogen from the animal waste before the nitrogen compounds are converted to ammonia and lost to the atmosphere.

For the current study, the Midwest RPO and the states opted to analyze a 10–15% reduction in ammonia emissions from agricultural sources. The methods of achieving this emission reduction and the distribution of the reduction among different types of farms would be flexible.

5.4.1 Factor 1 – Costs

Limited information is available on the cost of control measures for agricultural ammonia emissions. Table 5.4-1 analyzes control measures from the previous list for which cost information is available. The table shows the estimated fraction of the overall ammonia inventory which could be controlled, the emission control efficiency, the potential emission reduction, and the cost effectiveness of each control measure. The options are sorted in increasing order of cost effectiveness.

The costs of tree plantings are based on an analysis by the Iowa Agricultural Extension Service.[34] The potential effectiveness of trees for reducing ammonia emissions is based on measurements by the University of Delaware over a four year period at a poultry house. The wide range of cost effectiveness values for this control measure result from the variability of emission reductions during the measurement study.[35] At least one other research group has been investigating the effectiveness of tree plantings for reducing ammonia emissions, but quantitative emission reduction results are not yet available.[36]

Table 5.4-1. Estimated Cost Effectiveness of Control Measures for Agricultural Ammonia Emissions

Description	Fraction of the overall NH3 emissions inventory that can be controlled using this option	Estimated reduction efficiency for the affected category (%)	Potential reduction in overall inventory (%)	Cost effectiveness ($/ton)
Vegetative buffers for houses and storage facilities	57	15 - 77	9 - 44	31 - 160
Vegetative buffers for entire farms	100	9 - 21	9 - 21	na
Feed adjustments for swine	20	4 - 16	1 - 3	0 - 21000
Reduce usage of nitrogen fertilizer	5	50	2	potential savings
Incorporation of pig slurry by disc	4	36 - 70	2 - 3	600 - 1200
Replace urea with lower emission fertilizer	2	75 - 95	2	400 - 500
Incorporation of poultry manure by disc	4	36 - 80	2 - 3	600 - 1500
Incorporation of beef cattle manure by disc	4	36 - 70	1 - 3	2500 - 4000
Incorporation of dairy slurry by disc	12	70	9	2700
Incorporation of dry dairy manure by disc	7	36 - 70	3 - 5	2700 - 5200

Cost estimates for feed adjustments varied over a broad range. One U.S. researcher indicated that a diet adjustment designed to reduce the amount of crude protein could be made at little or no cost.[37] However, a British study estimated the cost of a staged feeding program to reduce the levels of nitrogen compounds in waste at $21,000 per ton of ammonia emission reduced.[38]

The British cost study also estimated the cost effectiveness of a number of other control options, including the incorporation of animal waste into the soil. However, the emission reduction reported for these measures in the British study were considerably higher than those reported in BMP guidelines from the Minnesota Agricultural Extension Service. The broad ranges of cost effectiveness values for these measures generally reflect the differences in estimated efficiencies between the British study and the BMP guideline estimates. For instance, the British study estimates that an emission reduction of 70% can be achieved by incorporating pig slurry into the soil when it is applied to crop lands. With an emission reduction of 70%, the cost effectiveness of this control measure is estimated at $600/ton of emission reduction. However, the Minnesota Agricultural Extension service estimates the efficiency of this control measure at only 36%. This lower estimate would increase the cost per unit of emission control to about $1200/ton.

Based on the information presented in Table 5.4-1, the cost effectiveness of achieving a 10–15% reduction in agricultural emissions could be as low as $31 per ton, corresponding with the low end of the cost estimate and a moderate efficiency for tree plantings. A number of other options are available for less than $2,700 per ton.

5.4.2 Factor 2 – Time Necessary for Compliance

As discussed above, the use of trees to absorb ammonia emissions could be the most effective control measure for agricultural sources. The cost estimates for Factor 1 are based on planting trees at about $25 each, with a height of about 6 feet. These trees would require a number of years to reach their full emission reduction effectiveness. Taller trees, at about 12 feet, could be purchased for about $150 each. The trees tested in the Delaware study were 14 to 18 feet tall.

We have estimated the time required for tree plantings to reach their full effectiveness at 3–10 years, depending on the size of trees planted. The other control options for agricultural ammonia emissions could be achieved within a year.

5.4.3 Factor 3 – Energy and Other Impacts

The control options involving incorporation of animal waste into the soil would require additional energy usage to run farm tractors for the incorporation step. The British cost study quantified the numbers of hours of tractor usage which would be required to incorporate a given volume of animal waste, and we have used these figures to estimate the amount of additional diesel fuel that would be required. We have also estimated the amount of additional CO_2 which would be produced in the burning of this fuel (Table 5.4-2).

Table 5.4-2. Estimated Energy and Non-Air Environmental Impacts of Agricultural Ammonia Emission Control Measures

Description	Additional diesel requirements (gal/Mg NH3 reduced)	Carbon dioxide generated (tons/ton NH3 reduced)
Vegetative buffers for houses and storage facilities	0	reduction
Vegetative buffers for entire farms	0	reduction
Feed adjustments for swine	0	0
Incorporation of pig slurry by disc	200 - 500	300 - 600
Replace urea with lower emission fertilizer	0	0
Incorporation of poultry manure by disc	200 - 600	200 - 700
Incorporation of beef cattle manure by disc	200 - 400	200 - 500
Incorporation of dairy slurry by disc	1300 - 1500	1400 - 1700
Incorporation of dry dairy manure by disc	400 - 900	400 - 1000

Control measures which involve the use of additives, such as alum, in animal wastes may have adverse impacts when the waste is spread on fields. However, these options do not appear to be as cost effective as other available options, and are not expected to be used to attain a 10–15% emission reduction.

Vegetative buffers, animal feed adjustments, and measures to reduce fertilizer usage would require no additional energy usage and would produce no additional solid waste. In fact, trees planted to absorb ammonia would also have the benefit of absorbing CO_2.

Any control measure to reduce emissions of ammonia will have the benefit of reducing nitrogen deposition. In addition, although ammonia acts as an alkaline buffer in the atmosphere, it can be oxidized to form nitrate once it is deposited to natural landscapes. Thus, control measures to reduce ammonia can also reduce the acidification of soils and waterbodies. The ammonia control measures considered in the current study are designed to reduce the formation of fine particles that impair visibility. Such reductions would also result in decreases in the ambient levels of $PM_{2.5}$, with corresponding health benefits.

5.4.4 Factor 4 – Remaining Equipment Life

Factor 4 does not generally apply to agricultural emissions of ammonia. Livestock are generally replaced when they are slaughtered, and the fields on which animal waste and fertilizer are spread do not have a service life in the same sense as a piece of equipment. Animal houses and waste storage facilities do have a limited service life; however, the controls which appear to be the most cost effective for these sources are not typical add-on controls. Tree plantings would be effective for the replacement facilities as long as they are built in the same place. Nor are animal feed adjustments tied to the building or the waste storage facility. Add-on controls such as covers and ammonia capture devices are more expensive, and are not expected to be used to obtain a 10–15% emission reduction.

5.4.5 Factor 5 – Visibility Impacts

Table 5.4-3 presents the estimated visibility impacts at the four northern-Midwest Class I areas for the agricultural ammonia control strategy, implemented over the three-state region and the nine-state region. Table 5.4-3 estimates the cost effectiveness of ammonia emission reductions in terms of the cost per emission reduction and the cost per visibility improvement. It must be noted that the estimates of visibility improvement are subject to considerable uncertainty. These are based on rollback calculations using the results of PSAT analyses and CAMx sensitivity analysis. These rollback calculations provide a mechanism for evaluating the relative impacts of different strategies. However, they may over-estimate or under-estimate the impacts of NH_3 controls relative to SO_2 or NO_X controls. More detailed modeling using CAMx or other photochemical models is needed to fully quantify the impact of any given control strategy.

Table 5.4-3. Estimated Visibility Impacts of Agricultural Ammonia Emission Control Measures

Strategy and region	Estimated visibility improvement in 2018 (deciviews) Boundary Waters	Voya-geurs	Isle Royale	Seney	Average
10% Ammonia reduction in the 3-State region	0.09	0.11	0.10	0.10	0.10
10% Ammonia reduction in the 9-State region	0.15	0.18	0.15	0.17	0.16
15% Ammonia reduction in the 3-State region	0.14	0.17	0.15	0.14	0.15
15% Ammonia reduction in the 9-State region	0.23	0.27	0.23	0.26	0.25

Table 5.4-4. Cost Effectiveness of Agricultural Ammonia Emission Control Measures in Terms of Visibility Improvement

Strategy and region	Average cost effectiveness per emission reduction ($/ton)	Average cost effectiveness per visibility improvement ($million/dV)
10% Ammonia reduction in the 3-State region	31 - 2,700	8 - 750
10% Ammonia reduction in the 9-State region	31 - 2,700	18 - 1,500
15% Ammonia reduction in the 3-State region	31 - 2,700	8 - 750
15% Ammonia reduction in the 9-State region	31 - 2,700	18 - 1,500

5.5 Mobile Sources

Despite projected NO_X reductions from on-the-books Federal and state-wide programs targeting on- and non-road mobile source sectors as well as locomotives and marine engines, source apportionment analyses demonstrate that mobile sources still contribute significantly to visibility impairment in 2018 in the northern Midwest Class I areas. Potential additional control strategies were identified that could be applied on a regional level (see Appendix A). From this list, the following strategies were analyzed:

- For on-road engines:
  - Low-NO_X Reflash
  - Anti-Idling
  - Midwest Clean Diesel Initiative (MCDI)
  - Cetane Additive Program
- For non-road and locomotive engines:
  - Anti-Idling
  - Cetane Additive Program
  - MCDI

In addition to the above strategies, we also include a qualitative discussion of using biodiesel as an alternative fuel (see Section 5.5.6). Studies have shown that biodiesel does not reduce NO_X emissions, and may in fact show an increase of 2-4%.[39,40,41] However, biodiesel blends have been implemented in several states as part of the MCDI, or as an alternative fuel strategy to reduce PM emissions.

We relied primarily on the *Evaluation of Candidate Mobile Source Control Measures for LADCO States in 2009 and 2012* (ENVIRON report)[42] for the factor analyses of these strategies. This report provides example reduction strategies and discussion for Low-NO_X Reflash, MCDI projects, and anti-idling strategies. We obtained information on the cetane program from various studies that examine the effect of cetane additives on NO_X emissions.[43,44,45]

Low-NO_X Reflash affects 1993-1999 model year Class 7 and 8 heavy-duty diesel vehicles (HDDV) with model year 1993-1998 engines manufactured by Caterpillar, Cummins, Detroit Diesel, Mack/Renault, Volvo, and International. These seven corporations implemented advanced computer controls that, while maximizing fuel economy, also increased NO_X emissions during certain duty cycles. Consent decrees require these manufacturers to install low-NO_X software upgrades free of charge. The program has not progressed as quickly as anticipated, so additional mandatory programs or voluntary incentives are being explored to hasten installation of the software.

The MCDI is a collaborative organization between federal, state, and local agencies, and funds projects that will reduce diesel emissions through operational changes, technological improvements, and cleaner fuels. The initiative has been funded since 2002 by federal, state, local, and private agencies for the states of Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. It has been assumed for this analysis that funding will continue at a constant level at least through 2018 for similar projects, and will be expanded to the 9-state region. Because the majority of projects to date target on-road engines, the factor analysis has only been conducted on that sector.

Anti-idling strategies have been implemented in approximately 15 states and dozens of counties (including Minnesota and Wisconsin) to reduce emissions from on-road, non-road and locomotive engines. These strategies take the form of enforced shutdown policies, auxiliary power units (APUs), automatic engine shut-off technology, and truck stop electrification (TSE).

The on- and non-road cetane program would introduce additives to diesel fuel at the distribution source to increase the cetane number to approximately 50. This program has been shown to improve fuel economy and decrease NO_X emissions in all non-road engines and in 2002 and earlier model year on-road engines.[116]

5.5.1 Factor 1 – Costs

Table 5.5-1 summarizes the estimated cost effectiveness of various control measures for mobile source emissions. The table also shows the estimated effectiveness of each control measure, the approximate contribution of the affected emission source to the overall inventory (where available), and the estimated potential reduction in the overall inventory.

NO_X emissions were obtained from the 2012 and 2018 Base K Strategy 1 inventory for the 3-state and 9-state regions.[a] Emissions data for 2018 were not available for Missouri, Iowa, North Dakota, or South Dakota.

Cost-effectiveness and emission reductions for low-NO_X reflash, MCDI, and anti-idling programs were obtained primarily from the ENVIRON report. It was assumed that percentage of emissions reduced and cost-effectiveness achieved in the LADCO region would be applicable to the 3-state and 9-state regions examined in this analysis. Potential emission reductions for the cetane program were obtained from the southeast Michigan fuels study,[43] and cost-effectiveness was obtained from a study conducted in Nashville, TN.[44]

The ENVIRON report presents a combined PM, VOC, and NO_X cost-effectiveness for the MCDI and anti-idling strategies. Cost-effectiveness for NO_X was calculated based on the percentage of NO_X reductions achieved by each strategy. For this analysis, it was assumed that the amount of funding for MCDI projects would be distributed in a similar fashion to current projects. This assumption resulted in a high cost-effectiveness for NO_X reductions, especially for the 3-state region, because MCDI projects focused primarily on PM emissions. Specifically, the ENVIRON report did not identify any NO_X reductions for programs in Wisconsin or Minnesota, as those states focused on diesel retrofits and biofuels for PM reductions. However, the 9-state region achieved larger NO_X reductions and lower cost-effectiveness due largely to the amount of funding devoted to idling restrictions in the Chicago, IL metropolitan area.[42]

While anti-idling policies and technologies were included as part of the MCDI strategy, a separate analysis was also conducted by ENVIRON for idle reduction strategies for on-road and non-road engines, and line haul and switching locomotives. The majority of emission reductions achieved by anti-idling policies were NO_X reductions, resulting in a cost-effectiveness of \$1,400-\$3,600 per ton. Cost-effectiveness was calculated assuming that automatic shut-off and/or APU

[a]The ENVIRON report provided alternate 2012 emissions data for the LADCO states and Minnesota, but the Base K inventory was used for consistency between 2012 and 2018.

technology would be installed to reduce idling. Truck-stop electrification (TSE) was also factored into on-road idle reduction strategies.

The cost-effectiveness of anti-idling strategies for on-road engines reflects a net annualized savings of $200-430 per vehicle for APUs and/or automatic shutoff technology, and $1,700 per ton for TSE. Fuel and maintenance savings were not calculated for non-road or locomotive shutoff technology, but one study estimated a payback period of approximately 2.5 years due to fuel and maintenance savings.[46]

For the cetane program, the fraction of emissions reduced from the on-road inventory accounts for the fact that reductions would only apply to 2002 and older model years. It was assumed that the percentage of emission reductions possible in southeast Michigan would be applicable to the regional inventory.

Table 5.5-1. Estimated Cost Effectiveness and Emission Reduction Potential of Mobile Source Controls for the 3-State and 9-State Regions

Strategy	Inventory	Affected Category	Estimated reduction efficiency for the affected category (%)	Potential fraction of overall inventory affected (%)	Potential reduction for inventory (%) 2012	2018	Cost effectiveness ($/ton)	Note
			3-State Region					
Low-NOX Reflash	On-Road	All MDDV and HDDV Class 8 Vehicles	23%	25%	5.8%	5.8%	$241	
MCDI	On-Road	Class 8 Vehicles	2% in 2012, 5% in 2018	36%	0.7%	1.8%	$10,697	a
	Non-Road	Diesels	2% in 2012, 5% in 2018	71%	1.4%	3.6%	$10,697	
	M/A/R	Switching and Line-Haul Locomotives	2% in 2012, 5% in 2018	42%	0.8%	2.1%	$10,697	
Anti-Idling	M/A/R	Switching Locomotives	9% in 2012, 18% in 2018	5%	0.4%	0.9%	$1,400	a
		Line-Haul Locomotives	2% in 2012, 4% in 2018	37%	0.7%	1.5%	$1,400	
	On-Road	All MDDV and HDDV Class 8 Vehicles	2.6%	36%	0.9%	0.9%	(430) - 1,700	
	Non-road	Non-road diesel engines	1.5%	71%	1.1%	1.1%	$3,577	b
Cetane Additive Program	Non-road	All diesel engines	1.0%		2.9%	2.9%	$4,119	c
	On-Road	MY2002 and earlier MDDV and HDDV	2.9%		1.6%	1.5%	$4,119	c
			9-State Region					
Low-NOX Reflash	On-Road	All MDDV and HDDV Class 8 Vehicles	23%	25%	5.8%	5.8%	$241	
MCDI	On-Road	Class 8 Vehicles	2% in 2012, 5% in 2018	36%	0.7%	1.8%	$2,408	
	Non-Road	Diesels	2% in 2012, 5% in 2018	75%	1.5%	3.7%	$2,408	
	M/A/R	Switching and Line-Haul Locomotives	2% in 2012, 5% in 2018	56%	1.1%	2.8%	$2,408	
Anti-Idling	M/A/R	Switching Locomotives	9% in 2012, 18% in 2018	2%	0.2%	0.4%	$1,400	a
		Line-Haul Locomotives	2% in 2012, 4% in 2018	24%	0.5%	1.0%	$1,400	b
	On-Road	All MDDV and HDDV Class 8 Vehicles	2.6%	36%	0.9%	0.9%	(430) - 1,700	
	Non-road	Non-road diesel engines	1.5%	75%	1.1%	1.1%	$3,577	
Cetane Additive Program	Non-road	All diesel engines	1.0%		2.9%	2.9%	$4,119	c
	On-Road	MY2002 and earlier MDDV and HDDV	2.9%		1.6%	1.4%	$4,119	c

[a] Reduction efficiency depends on market penetration, funding, and/or regulatory development for these control measures

[b] Assumes equipment life of 20 years at an interest rate of 7%

[c] Cost-effectiveness taken from Davis, W. T., and T. L. Miller. "Estimates of potential emissions reductions for the Nashville ozone early action compact area, Final Report," prepared for the Nashville Department of Environment and Conservation, March 2004.

5.5.2 Factor 2 – Time Necessary for Compliance

Overall, the strategies chosen for analysis could be implemented in a relatively short time frame. For the low-NO_X reflash program, the ENVIRON report assumes that all emission reductions from the program would be implemented by 2012, or 4 years from the first SIP implementation in 2008. The groundwork is in place to adopt a mandatory or voluntary program to accelerate installation of low-NO_X software. Although California's efforts to establish a mandatory program have stalled due to recent court action,[47] NESCAUM with the support of the Ozone Transport Commission (OTC) has developed a model rule that the Midwest could adopt. Cooperative efforts could also be pursued with engine manufacturers to coordinate software downloads with routine engine maintenance.[48]

The Midwest Clean Diesel Initiative's primary goal is to decrease emissions from 1 million diesel engines by 2010. However, this analysis assumes that the MCDI would receive a constant amount of funding and implement similar emission reduction programs through at least 2018.[49]

Anti-idling policies have been implemented by local agencies in Illinois, Missouri, Minnesota and Wisconsin.[50] We estimate a time frame of 16-20 months to adopt a regional anti-idling policy, based on the time required to develop a program in California.[51] Voluntary efforts could also be undertaken to establish anti-idling corridors, such as the Everybody Wins strategy developed by LRAPA.[52] Depending on funding, an anti-idling corridor could be established within 2-5 years.

A cetane program targeting on- and non-road diesel fuel may require the need for regulatory action. According to EPA guidance, States have the authority to implement a program that will increase the cetane number with additives as long as it does not change the cetane index or aromatics properties of the fuel.[53] Extrapolating from the southeast Michigan study, a cetane program could be potentially implemented in a two-year time frame.

5.5.3 Factor 3 – Energy and Other Impacts

Table 5.5-2 qualitatively summarizes energy and other impacts of the mobile source strategies. Fuel economy benefits can be seen as a result of the MCDI, anti-idling, and cetane programs, while a negligible disbenefit can be seen from installation of the low-NO_X reflash software. Co-benefits of greenhouse gas and other criteria pollutant reductions can be seen as a result of all programs except low-NO_X reflash, which may result in a 7% PM emissions increase per vehicle.[116]

5.5.4 Factor 4 – Remaining Equipment Life

Remaining useful life of mobile sources may have some effect on control strategy effectiveness, particularly those that target older model vehicles. Vehicle turnover would affect the on-road cetane program and the low-NO_X reflash program, because they target model years 2002 and earlier, and model years 1993-1999, respectively. All emission reductions from the low-NO_X program are expected to be achieved by 2012 either through installation of software or engine retirement. The cetane program is projected to achieve a lower emission reduction in the overall inventory due to vehicle turnover (see Table 5.5-1.)

5.5.5 Factor 5 – Visibility Impacts

Table 5.5-3 presents the estimated visibility impacts at the four northern-Midwest Class I areas for the candidate mobile source control strategies, implemented over the three-state region and the nine-state region. Table 5.5-4 estimates the cost effectiveness of mobile source controls, expressed in terms of cost per visibility improvement in deciviews.

It must be noted that the estimates of visibility improvement are subject to considerable uncertainty. These are based on rollback calculations using the results of PSAT analyses and CAMx sensitivity analysis. These rollback calculations provide a mechanism for evaluating the relative impacts of different strategies. However, they may over-estimate or under-estimate the impacts of NO_X controls relative to SO_2 controls. More detailed modeling using CAMx or other photochemical models is needed to fully quantify the impact of any given control strategy.

5.5.6 Biofuels

Biofuels, including biodiesel (i.e., alkyl esters made from the transesterification of vegetable oils or animal fats), and ethanol (i.e., a biomass alternative to gasoline manufactured primarily from corn, sugar beets, and sugar cane), have positive impacts on greenhouse gases and PM, but may have some negative impacts on NO_X. Although several studies have shown an increase in NO_X emissions from biodiesel, use of this fuel results in other environmental benefits, including a significant net reduction in solid waste and wastewater production.[54] Biodiesel in a 20% blend with petroleum diesel (B20) has been shown to reduce PM emissions by 10%, HC emissions by 21% and CO emissions by 11% in heavy-duty on-road engines. However, it may reduce fuel economy by 1-2%. Emission reductions of PM, HC, and CO generally increase as the percentage of biodiesel blend increases.[41]

Approaches have been studied that would mitigate NO_X emissions from biodiesel. These approaches include lowering the base fuel aromatic content from 31.9% to 7.5%, using kerosene as a base fuel in a B40 blend, and using cetane enhancers. All approaches result in a "NO_X-neutral" biofuel, with cetane enhancers proving the most cost-effective at an incremental cost of \$0.05 - \$0.16 per gallon for a 4% reduction in NO_X.[40]

The effect of ethanol blends on NO_X emissions also remains uncertain. The southeast Michigan fuels study demonstrated an increase of 2-4 tons per day in NO_X emissions from the use of an E10 gasoline blend, for example.[43] Studies conducted by CARB also indicate a NO_X disbenefit in vehicles model year 1988-1995. However, the effect of ethanol blends on NO_X emissions in vehicles newer than 1996 is uncertain, as the EPA Complex Model shows a slight decrease in NO_X emissions in those vehicles.

Table 5.5-2. Estimated Energy and Non-Air Environmental Impacts of Mobile Source Control Strategies

Strategy	Affected Category	Fuel Impacts	Other Air Quality Impacts	Environmental Impacts
Low-NOX Reflash	On-Road	<1% fuel economy penalty	7% increase in PM emissions per vehicle.	None
MCDI	On-Road	Anti-idling strategies funded by MCDI result in a fuel savings. (HDDV Idling generally uses 1 gallon/hr of fuel.)	Reductions in GHG, PM, VOC, and CO. Biodiesel strategies have a NOX emission penalty of up to 2% and a GHG reduction of 78% over petroleum diesel.	Anti-idling strategies have no quantifiable environmental impacts. Biodiesel productions results in a 79% reduction in wastewater and a 96% reduction in solid waste over petroleum diesel production.
Anti-Idling	M/A/R On-Road Non-road	Fuel savings	Reductions in GHG, PM, VOC, and CO. EPA cites a reduction of 22 pounds of GHG for every gallon of diesel fuel saved by anti-idling policies.	
Cetane Additive Program	Non-road On-Road	Improved fuel economy	PM2.5 emissions benefit	

Table 5.5-3. Estimated Visibility Impacts of Mobile Sources Control Strategies

Control strategy	Equipment covered	Inventory sector	Emission reduction in inventory sector (%)	Estimated visibility improvements (deciviews) Boundary Waters	Voyageurs	Isle Royale	Seney	Average
			3-State Region					
Low-NOX Reflash	All MDDV and HDDV Class 8 Vehicles	On-Road	5.8	0.006	0.007	0.009	0.006	0.007
MCDI	Class 8 Diesel Vehicles	On-Road	1.8	0.002	0.002	0.003	0.002	0.002
	Diesel Engines	Non-road	3.6	0.009	0.012	0.008	0.008	0.009
	Switching and Line-Haul Locomotives	M/A/R	2.1	0.004	0.005	0.003	0.003	0.004
Anti-Idling	Switching Locomotives	M/A/R	1.0	0.002	0.002	0.002	0.001	0.002
	Line-Haul Locomotives		1.7	0.003	0.004	0.003	0.002	0.003
	All MDDV and HDDV Class 8 Vehicles	On-Road	0.9	0.001	0.001	0.001	0.001	0.001
	Non-road diesel engines	Non-road	1.1	0.003	0.004	0.003	0.003	0.003
Cetane Additive Program	All diesel engines	Non-road	2.9	0.007	0.010	0.007	0.007	0.008
	MY2002 and earlier MDDV and HDDV	On-Road	1.4	0.002	0.002	0.002	0.001	0.002
			9-State Region					
Low-NOX Reflash	All MDDV and HDDV Class 8 Vehicles	On-Road	5.8	0.008	0.009	0.012	0.012	0.010
MCDI	Class 8 Vehicles	On-Road	0.7	0.001	0.001	0.001	0.002	0.001
	Diesel Engines	Non-road	3.6	0.010	0.013	0.009	0.009	0.010
	Switching and Line-Haul Locomotives	M/A/R	2.1	0.003	0.004	0.003	0.003	0.003
Anti-Idling	Switching Locomotives	M/A/R	0.2	0.000	0.000	0.000	0.000	0.000
	Line-Haul Locomotives		0.5	0.001	0.001	0.001	0.001	0.001
	All MDDV and HDDV Class 8 Vehicles	On-Road	0.9	0.001	0.001	0.002	0.002	0.002
	Non-road diesel engines	Non-road	1.1	0.003	0.004	0.003	0.003	0.003
Cetane Additive Program	All diesel engines	Non-road	2.9	0.004	0.005	0.006	0.006	0.005
	MY2002 and earlier MDDV and HDDV	On-Road	1.6	0.002	0.003	0.003	0.003	0.003

Table 5.5-4. Cost Effectiveness of Mobile Source Control Strategies in Terms of Visibility Improvement

Strategy	Mobile Sources Affected	Inventory	Cost effectiveness per visibility improvement ($million/ deciview)
	3-State Region		
Low-NOX Reflash	All MDDV and HDDV Class 8 Vehicles	On-Road	516
MCDI	Class 8 Diesel Vehicles	On-Road	22,947
	Diesel Engines	Non-Road	5,032
	Switching and Line-Haul Locomotives	M/A/R	5,033
Anti-Idling	Switching Locomotives	M/A/R	659
	Line-Haul Locomotives		659
	All MDDV and HDDV Class 8 Vehicles	On-Road	(920) - 3,600
	Non-road diesel engines	Non-Road	1,683
Cetane Additive Program	All diesel engines	Non-Road	1,938
	MY2002 and earlier MDDV and HDDV	On-Road	8,836
	9-State Region		
Low-NOX Reflash	All MDDV and HDDV Class 8 Vehicles	On-Road	616
MCDI	Class 8 Vehicles	On-Road	6,171
	Diesel Engines	Non-Road	3,952
	Switching and Line-Haul Locomotives	M/A/R	3,954
Anti-Idling	Switching Locomotives	M/A/R	2,299
	Line-Haul Locomotives	M/A/R	2,299
	All MDDV and HDDV Class 8 Vehicles	On-Road	(1,100) - 4,400
	Non-road diesel engines	Non-Road	5,872
Cetane Additive Program	All diesel engines	Non-Road	10,552
	MY2002 and earlier MDDV and HDDV	On-Road	10,554

5.6 Miscellaneous Facility Analyses

In addition to the analyses of EGUs, ICI boilers, and individual EGU and ICI facilities (see sections 5.1, 5.2, and Appendix C, respectively for those analyses), we also examined several other facilities in various sectors. The purpose is to determine the cost effectiveness of controlling these facilities in an effort to meet the reasonable progress goals set for 2008-2018. The facilities examined fall into the following categories: cement manufacturing (Holcim, Inc. in Dundee, MI), glass manufacturing (Cardinal FG in Menomonie, WI), lime manufacturing (Rockwell Lime Company in Manitowoc, WI; CLM Corporation in Superior, WI), and oil refineries (Murphy Oil in Superior, WI). Most of these are not subject to BART, and some had been identified by stakeholders due to their close proximity to the Class I areas.

5.6.1 Cement Plants

The main emission unit of interest at cement plants are the cement rotary kilns. There are two major types, wet and dry kilns, and subcategories within each type. On the whole, wet kilns tend to produce more tons of cement (or "clinker") but also require more energy than dry process kilns.[55] At the Holcim, Inc. plant, there are two long wet kilns producing approximately 1.2 million tons of clinker per year.[56] The kilns use a mixture of coal, coke, oil, natural gas, and tires as fuel. Table 5.6-1 lists the various control options for NO_X, and whether those options can be applied to the Holcim kilns. In Holcim's permit, they stated that they have begun testing a scrubber/oxidizer system at their plant (likely similar to the LoTOx system, a scrubber/oxidation process designed to lower the temperature needed to produce clinker), although no conclusions had yet been reported. There was limited information on SO_2 controls for cement kilns, particularly long wet kilns. Process modification and replacement of the kiln with a dry process kiln are the most feasible options for SO_2 control. SNCR is another control technology available to preheater or precalciner cement kilns[57]. SNCR has been tested primarily in European facilities and on at least one facility in the United States. However, the kilns at the facility in question are long wet rotating kilns which cannot use SNCR as a control method.[50,52]

Table 5.6-1. Control Technologies Available to Long Wet Kilns

Control Technology		Percent Efficiency	Applicable at Holcim plant
NO_X			
	Process modification (i.e., CemSTAR[a], fuel switching)	9-70	Yes
	Conversion to dry process kilns	65	Yes
	LoTox™ (lower temperature oxidation techology)	85	Yes
SO_2			
	Process modification	9-70	Yes
	Conversion to dry process kilns	65	Yes

5.6.1.1 Factor 1 - Costs

A 2006 report analyzed Texas wet kiln cement facilities, providing cost effectiveness figures for kilns of similar size and production as the Holcim plant in Michigan (the Ash Grove facility produces approximately 160 tons of clinker per hour versus Holcim's 137 tons of clinker per hour). Table 5.6-2 shows the cost effectiveness figures for NO_X control at the Holcim facility using the Ash Grove cost figures. Due to the limited amount of information available for SO_2 controls we were only able to determine a cost effectiveness figure for conversion to dry process.

[a]CemSTAR is a process that introduces steel slag into the rotary kiln, lowering the temperature necessary to produce clinker, thus reducing both NO_X and SO_2 emissions.

Table 5.6-2. Cost Effectiveness of NO_X and SO_2 Control Technologies for Holcim, Inc. Facility

Control Technology	Percent Efficiency	Emissions Reduction (tons/year)	Cost Effectiveness ($/ton reduced)
NO_X			
Conversion to Dry Process Kiln	65	946	9848
LoTOx™	85	1237	1399
Process Modification	9-70	131-1019	NA[a]
SO_2			
Conversion to Dry Process Kiln	65	4644	2010

5.6.1.2 Factor 2 - Time Necessary for Compliance

It is anticipated that states will require two years to create and promulgate the rule. Installation of a single NO_X system typically takes less than 18 months. However, since LoTOx™ requires a scrubber, it will take approximately 26 months to procure the necessary capital, plan, and construct the system. Similarly, we assume it will take approximately two years if the plant decides to replace the wet kilns with dry kilns. Therefore, it will take the facility a maximum of five years to come into compliance.

5.6.1.3 Factor 3 - Energy and Other Impacts

Information and data on the candidate control strategies for the Holcim facility were not available to determine energy and other impacts. LoTOx™, a relatively recent control strategy, does not require additional catalysts and will not likely add additional water or solid waste. It is also unclear whether process modifications (such as CemSTAR) or a conversion to a dry process kiln would add additional waste (solid or liquid), although dry process kilns tend to use less energy than wet kilns since water does not need to be heated to produce clinker.

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[a]CemSTAR requires little additional equipment and the steel slag may replace other materials used in the clinker process (such as shale or clay). The greatest amount of NO_X reductions for wet kilns can be achieved by CemSTAR because it greatly reduces the amount of heat required to produce clinker. Since the Holcim plant already burns a mixture of fuels fuel switching will likely not provide substantial emissions reductions at a cost effective rate. *(Natural gas tends to produce higher NOX emissions than coal although coal increases the amount of SO_2 emissions. Petroleum coke produces fewer NOX emissions although it must be burned in tandem with other fuels, and contains a high percentage of sulfur.)*

5.6.1.4 Factor 4 - Remaining Equipment Life

Cement kilns have no set equipment life. The units, whether wet or dry, can be refurbished to extend their lives. In addition, it is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for cement kilns.

5.6.1.5 Factor 5 - Visibility Impacts

Visibility impacts are presented in terms of the change in emissions per distance (Q/d). Deciview information for this facility was not available and thus not calculated. Table 5.6-3 presents the estimated visibility impacts at the four northern-Midwest Class I areas for the candidate cement kiln control strategies in terms of the change in emissions per distance (Q/d). The average visibility impact for each technology is also calculated along with the cost effectiveness.

The conversion to a dry kiln process is more expensive on a per mile basis than the EGU1 or EGU2 NO_X and SO_2 costs for the 3- and 9-state regions (Table 5.1-11). LoTox, on the other hand, is greater than the 3-state regional EGU1 cap, less than the 9-state EGU1 cap, and less than the 3- and 9-state EGU2 regional caps.

Table 5.6-3. Estimated Visibility Impacts of Control Strategies for Holcim Cement Kilns

Strategy	Baseline summations of emission-to-distance ratios (Q/d; tons/yr-mi)					Reductions in the summations of emission-to-distance ratios (Q/d; tons/yr-mi)*					Cost Effectiveness ($1000-mi/ton)
	Boundary Waters	Voyageurs	Isle Royale	Seney	Average	Boundary Waters	Voyageurs	Isle Royale	Seney	Average	
Conversion to Dry Process Kiln (NOx)	2.56	2.28	3.01	4.62	3.12	1.67	1.48	1.96	3.00	2.03	4594
LoTOx	2.56	2.28	3.01	4.62	3.12	2.18	1.94	2.56	3.93	2.65	653
Process Modification	2.56	2.28	3.01	4.62	3.12	1.01	0.901	1.19	1.82	1.23	NA
Conversion to Dry Process Kiln (SO2)	13	11	15	23	15	8	7	10	15	9.93	938

5.6.2 Glass manufacturing plant

The majority of NO_X and SO_2 emissions come from the melting furnace in glass plants due to the high temperatures and the fuels used. The facility under analysis (Cardinal FG in Wisconsin) is a flat glass manufacturing plant. Flat glass includes plate and architectual glass, mirrors, and automotive windscreens[a]. The Cardinal FG facility uses natural gas as the primary fuel in its melting furnace, and produces 600 tons per day. A dry scrubber system is already installed at the plant; therefore, SO_2 emissions will not need to be controlled at this facility.

The available NO_X control technologies available at glass manufacturing plants are listed in Table 5.6-4.[58]

5.6.2.1 Factor 1 - Costs

Due to insufficient information to determine cost equations for cost effectiveness figures, we provide the cost effectiveness figures from the Alternative Control Techniques document (U.S. EPA, 1994) for a model plant of comparable size to the Cardinal FG facility. The model plant produces 750 tons of flat glass per day; the Cardinal FG facility produces 600 tons of flat glass per day. Table 5.6-5 provides the capital costs, annual costs, annualized costs, and cost effectiveness for the above-listed technologies..

5.6.2.2 Factor 2 - Time Necessary for Compliance

It is anticipated that states will require two years to create and promulgate the rule. Installation of a single NO_X system typically takes less than 18 months. Again, the facility has already installed a scrubber system so SO_2 is not analyzed. Thus to bring the one furnace at the plant into compliance it will take a maximum of 3 years.

Table 5.6-4. NO_X Control Technologies Available for Melting Furnaces at the Cardinal FG Facility

Control Technology	Percent Efficiency	Applicable to Cardinal FG Facility
LNB	40	Yes
Oxy-firing[a]	85	Yes
Electric boost[b]	10	Yes
SCR	75	Yes
SNCR	40	Yes

a Process that uses oxygen and CO_2 to combust with fuel instead of air
b Electricity currents are added to the gas to aid in combustion in the furnace

[a]World Bank Group. 1998. “Glass Manufacturing.” Pollution Prevention and Abatement Handbook.

Table 5.6-5. Costs and Cost Effectiveness for NO_X Control Technologies Available to Cardinal FG Facility

Control Technology	Emissions reductions (tons/year)	Capital Cost (m$2005)	Annual Cost (m$2005)	Annualized Costs (m$2005)	Cost Effectiveness ($2005/ton)*
LNB	1014	1765	818	1055	1041
Oxy-firing	2283	12925	4730	6467	2833
Electric boost	202	-	692	692	3426
SCR	1951	3544	1581	2057	1054
SNCR	1048	2055	870	1146	1094

* Cost effectiveness values are from EPA's ACT documentation for NOX emissions from glass manufacturing, and reflect a model glass manufacturing plant producing 750 tpd. Cardinal FG facility produces 600 tpd.

5.6.2.3 Factor 3 - Energy and Other Impacts

The following factors were used to determine the non-air impacts of SCR and SNCR. Sufficient information for LNB, Oxy-firing, and electric boost was not available. For SCR:

- 0.021 tons of catalyst waste are generated for each ton of NO_X reduced
- 0.89 mWh electricity used/ton NO_X reduced
- 0.25 tons of steam produced/ton NO_X reduced
- 1 ton of CO_2 produced/mWh of electricity used
- 0.6 tons of CO_2 produced/ton steam produced

The results are presented in Table 5.6-6.

Table 5.6-6. Estimated Energy and Non-Air Environmental Impacts of Control Strategies at Cardinal FG Glass Manufacturing Facility

Strategy	Additional electricity requirements (GW-hrs /year)	Steam requirements (1000 tons/yr)	Wastewater produced (million gallons/year)	Solid waste produced (1000 tons/year)	Additional CO2 emitted (1000 tons/year)
SCR	0.8	0.2	-	0.9	0.9
SNCR	0.007	-	-	0.007	0.01

5.6.2.4 Factor 4 - Remaining Equipment Life

Glass furnaces have no set equipment life. The units can be refurbished to extend their lives. In addition, it is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for glass furnaces.

5.6.2.5 Factor 5 - Visibility Impacts

Visibility impacts are presented in terms of the change in emissions per distance (Q/d). Deciview information for this facility was not available and thus not calculated. Table 5.6-7 presents the estimated visibility impacts at the four northern-Midwest Class I areas for the candidate glass furnace control strategies. The average visibility impact for each technology is also calculated along with the cost effectiveness.

LNB and SCR are less expensive on a per mile basis than the EGU1 or EGU2 costs of potential control measures for the 3- and 9-state regions (see Table 5.1-11 for regional costs). Oxy-firing and electric boost, on the other hand, are more expensive than the 3- and 9-state EGU1 and EGU2 regional caps. Finally, SNCR is more expensive than the 3-state EGU1 regional cap, and is less expensive than the costs 9-state EGU1 regional cap and the 3- and 9-state EGU2 regional caps.

Table 5.6-7. Estimated Visibility Impacts of Control Strategies for Cardinal FG Glass Furnaces

	Baseline summations of emission-to-distance ratios (Q/d; tons/yr-mi)					Reductions in the summations of emission-to-distance ratios (Q/d; tons/yr-mi)*					
Strategy	Boundary Waters	Voyageurs	Isle Royale	Seney	Average	Boundary Waters	Voyageurs	Isle Royale	Seney	Average	Cost Effectiveness ($1000-mi/ton)
LNB	6.44	5.51	5.33	4.45	5.43	2.58	2.20	2.13	1.78	2.17	486
Oxy-firing	6.44	5.51	5.33	4.45	5.43	5.48	4.68	4.53	3.78	4.62	1,401
Electric Boost	6.44	5.51	5.33	4.45	5.43	0.644	0.551	0.533	0.445	0.543	1,274
SCR	6.44	5.51	5.33	4.45	5.43	4.83	4.13	3.99	3.33	4.07	505
SNCR	6.44	5.51	5.33	4.45	5.43	2.58	2.20	2.13	1.78	2.17	528

5.6.3. Lime Manufacturing Plants

Lime manufacturing is the product of the calicination of limestone, and is created in kilns. These kilns are fueled by coal, oil, and/or natural gas. The primary source of SO_2 emissions is the kiln fuel, and a large portion of the fuel sulfur is not emitted as it reactions with calcium oxides produced in the kiln during the lime production process. Table 5.6-8 presents the control technologies available for lime manufacturing plants (Pechan, 1998), their reduction efficiencies, and their applicability to the two individual facilities analyzed: Rockwell Lime Company and CLM Corporation, both located in Wisconsin.

Table 5.6-8. Control Technologies Available for Lime Manufacturing Plants

Control Technology		Percent Efficiency	Applicable at Rockwell	Applicable at CLM
NO_X				
	Mid-kiln firing	30	Yes	Yes
	LNB	30	Yes	Yes
	SNCR	50	Yes	Yes
	SCR	80	Yes	Yes
SO_2				
	FGD	90	Yes	Yes

The only SO_2 control technology for which information was available for lime manufacturing plants is flue gas desulfurization (FGD).

5.6.3.1 Factor 1 - Costs

AirControlNET documentation provided cost equations for the capital, and operations and maintenance costs for SO_2 controls. Cost equations were not available for NO_X controls, although AirControlNET did provide default cost effectiveness values, and should be considered conservative estimates for the CLM Corporation and Rockwell facilities. The results are presented in tables 5.6-9.

Table 5.6-9. Costs and Cost Effectiveness for NOx and SO2 Control Technologies at Rockwell and CLM Corporation Lime Manufacturing Facilities*

Facility	Control Technology	Percent Efficiency	Emissions Reduction (tons)	Total Annualized Costs ($M2005)	Cost Effectiveness ($2005/ton)
CLM Corp.	Mid-kiln firing	30	84.4	58	688
	LNB	30	84.4	71	837
	SCR	50	141	710	5,037
	SNCR	80	225	272	1,211
	FGD	90	127	641	4,828
Rockwell	Mid-kiln firing	30	4.14	2.85	688
	LNB	30	4.14	3.47	837
	SCR	50	6.90	34.8	5,037
	SNCR	80	11.03	13.4	1,211
	FGD	90	152	19.4	128

* Cost effectiveness numbers were taken from AirControlNET documentation and may not reflect the actual cost effectiveness for these two particular facilities.

5.6.3.2 Factor 2 - Time Necessary for Compliance

It is anticipated that states will require two years to create and promulgate the rule. Installation of a single NO_X system typically takes less than 18 months. The typical amount of time to set up a SO_2 system is 26 months. Each additional SO_2 emissions unit requires 3 more months. It is anticipated it will take the CLM Corporation facility 5 years to come into compliance, and Rockwell five and a half years to come into compliance.

5.6.2.3 Factor 3 - Energy and Other Impacts

The following factors were used to determine the non-air impacts of SCR and SNCR. Sufficient information for LNB, Oxy-firing, and electric boost was not available. For SCR:

- 0.021 tons of catalyst waste are generated for each ton of NOX reduced
- 0.89 mWh electricity used/ton NOX reduced
- 0.25 tons of steam produced/ton NOX reduced
- 2.8 tons of sludge/ton SO_2 reduced
- 3.7 gallons of water/ton SO_2 reduced
- 1 ton of CO_2 produced/mWh of electricity used
- 0.6 tons of CO_2 produced/ton steam produced

The results are presented in Table 5.6-10.

Table 5.6-10. Estimated Energy and Non-Air Environmental Impacts of Control Strategies at Rockwell and CLM Corporation Lime Manufacturing Facilities

Facility	Strategy	Additional electricity requirements (GW-hrs /year)	Steam requirements (1000 tons/yr)	Wastewater produced (million gallons/year)	Solid waste produced (1000 tons/year)	Additional CO2 emitted (1000 tons/year)
CLM Corp.	SCR	0.25	0.07	NA	6	0.292
	SNCR	0.004	-	NA	-	0.004
	FGD	0.133	0.332	0.0005	0	0.332
Rockwell	SCR	12.3	3.45	-	0.290	14.3
	SNCR	0.349	-	-	-	0.349
	FGD	0.071	0.202	0.0003	0.227	0.202

5.6.3.4 Factor 4 - Remaining Equipment Life

Lime kilns, like cement kilns, have no set equipment life. The units can be refurbished to extend their lives. In addition, it is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for lime kilns.

5.6.3.5 Factor 5 - Visibility Impacts

Visibility impacts are presented in terms of the change in emissions per distance (Q/d). Table 5.6-11 presents these impacts at the four northern-Midwest Class I areas for the candidate lime kiln control strategies. The average visibility impact for each technology is also calculated along with the cost effectiveness. Again, the cost effectiveness values for NOX technologies were presented by AirControlNET without background information on the size of the kilns, and so while the numbers reflect inexpensive technologies (and visibility cost effectiveness), these are conservative estimates. Additionally, the emissions are already low for the Rockwell facility.

With the exception of FGD and SNCR for the CLM Corporation facility, all other candidate technologies are less expensive than the EGU1 and EGU2 3- and 9-state regional caps costs (Table 5.1-11).

Table 5.6-11. Estimated Visibility Impacts of Control Strategies for Rockwell and CLM Corporation Lime Kilns

		Baseline summations of emission-to-distance ratios (Q/d; tons/yr-mi)					Reductions in the summations of emission-to-distance ratios (Q/d; tons/yr-mi)					
Facility	Strategy	Boundary Waters	Voyageurs	Isle Royale	Seney	Average	Boundary Waters	Voyageurs	Isle Royale	Seney	Average	Cost Effectiveness ($1000-mi/ton)
CLM Corporation	Mid-kiln firing	3.21	2.34	1.65	0.98	2.04	0.964	0.702	0.494	0.293	0.613	94.6
	LNB	3.21	2.34	1.65	0.98	2.04	0.964	0.702	0.494	0.293	0.613	116
	SCR	3.22	2.34	1.65	0.98	2.04	2.57	1.87	1.32	0.781	1.64	434
	SNCR	3.21	2.34	1.65	0.98	2.05	1.61	1.17	0.824	0.488	1.02	1,185
	FGD	1.10	0.800	0.563	0.333	0.698	0.988	0.720	0.507	0.300	0.629	1,020
Rockwell	Mid-kiln firing	0.189	0.157	0.229	0.356	0.233	0.0566	0.047	0.069	0.107	0.070	40.9
	LNB	0.189	0.157	0.229	0.356	0.233	0.0944	0.078	0.114	0.178	0.116	29.8
	SCR	0.189	0.157	0.229	0.356	0.233	1.69	1.40	2.05	3.19	2.08	16.7
	SNCR	0.189	0.157	0.229	0.356	0.233	0.151	0.125	0.183	0.285	0.186	72.0
	FGD	1.81	1.50	2.19	3.41	2.23	0.0566	0.047	0.069	0.107	0.070	278

5.6.4. Oil Refinery

For our analysis the emissions units of interest at oil refineries are the process heaters and the fluid catalytic cracking unit (FCCU). Process heaters transfer the heat created through the burning of fuels to other processes in the production line. FCCUs convert heavy hydrocarbons into lighter hydrocarbons (ExxonMobil, 2006). Of the three process heaters at Murphy Oil, one runs on oil and the other two run on natural gas. Table 5.6-12 presents the control technologies available for oil refineries, their reduction efficiencies, and their applicability to the facility analyzed: Murphy Oil, USA in Wisconsin.

Table 5.6-12. Control Technologies Available for the Murphy Oil Refinery

Control Technology	Percent Efficiency	Applicable at Murphy Oil
NO_X		
LNB	50	Yes
SNCR	60	Yes
SCR	75	Yes
LNB+FGR[a]	55	Yes
ULNB	75	Yes
SO_2		
FGD[b]	90	Yes

a FGR is flue gas recirculation
b FGD is flue gas desulfurization

5.6.3.1 Factor 1 - Costs

AirControlNET documentation provided cost equations for the capital, and operations and maintenance costs for SO_2 controls. Cost equations were not available for NO_X controls, although AirControlNET did provide default cost effectiveness values. Tables 5.6-13 and 5.6-14 present the results.

Table 5.6-13. Cost Effectiveness of NO_X Control Technologies at Model Oil Refinery

Control Technology	Percent Efficiecy	Total Emissions Reduction (tons)	Cost Effectiveness ($/ton)
LNB	50	159	3288
SNCR	60	191	4260
SCR	75	239	17997
LNB+FGR	55	175	4768
ULNB	75	239	2242

Table 5.6-14. Cost Effectiveness for SO2 Control Technologies for Murphy Oil Refinery Facility

Control Technology	Percent Efficiency	Total Emissions Reduction (tons)	Total Annualized Costs (M$2005)	Cost Effectiveness ($2005/ton)
FGD	90	538	580,390	1078

5.6.3.2 Factor 2 - Time Necessary for Compliance

It is anticipated that states will require two years to create and promulgate the rule. Installation of a single NO_X system typically takes less than 18 months. The typical amount of time to set up a SO_2 system is 26 months. Each additional SO_2 emissions unit requires 3 more months. It is anticipated it will take the Murphy Oil facility a maximum of 6 years to come into compliance.

5.6.2.3 Factor 3 - Energy and Other Impacts

The following factors were used to determine the non-air impacts of SCR, SNCR, and FGD. Sufficient information for LNB, Oxy-firing, and electric boost was not available. For SCR:

- 0.021 tons of catalyst waste are generated for each ton of NO_X reduced
- 0.89 mWh electricity used/ton NO_X reduced
- 0.25 tons of steam produced/ton NO_X reduced
- 2.8 tons of sludge/ton SO_2 reduced
- 3.7 gallons of water/ton SO_2 reduced
- 1 ton of CO_2 produced/mWh of electricity used
- 0.6 tons of CO_2 produced/ton steam produced

The results are presented in Table 5.6-15.

Table 5.6-15. Estimated Energy and Non-Air Environmental Impacts of Control Strategies at Murphy Oil Refinery Facility

Strategy	Additional electricity requirements (GW-hrs /year)	Steam requirements (1000 tons/yr)	Wastewater produced (million gallons/year)	Solid waste produced (1000 tons/year)	Additional CO2 emitted (1000 tons/year)
SCR	.0009	.0003	-	.02	.9
SNCR	.00002	-	-	-	.02
FGD	1	1	0.002	2	1

5.6.3.4 Factor 4 - Remaining Equipment Life

Process heaters and FCCUs have no set equipment life. The units can be refurbished to extend their lives. In addition, it is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for oil refineries
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5.6.3.5 Factor 5 - Visibility Impacts

Visibility impacts are presented in terms of the change in emissions per distance (Q/d). Table 5.6-16 presents the estimated visibility impacts at the four northern-Midwest Class I areas for the candidate oil refinery control strategies. The average visibility impact for each technology is also calculated along with the cost effectiveness.

All control technologies, with the exception of SCR, are less expensive than the costs to reach the 3- and 9-state EGU1 and EGU2 regional caps. SCR is more expensive for both the 3- and 9-state EGU1 and EGU2 regional caps (see Table 5.1-11).

Table 5.6-16. Estimated Visibility Impacts of Control Strategies for Murphy Oil Refineries

Strategy	Baseline summations of emission-to-distance ratios (Q/d; tons/yr-mi) Boundary Waters	Voyageurs	Isle Royale	Seney	Average	Reductions in the summations of emission-to-distance ratios (Q/d; tons/yr-mi)* Boundary Waters	Voyageurs	Isle Royale	Seney	Average	Cost Effectiveness ($1000-mi/ton)
LNB	3.51	2.59	1.84	1.10	2.26	1.75	1.30	0.921	0.552	1.13	243
SCR	3.51	2.59	1.84	1.10	2.26	2.10	1.56	1.10	0.662	1.36	1,661
SNCR	3.51	2.59	1.84	1.10	2.26	2.63	1.95	1.38	0.828	1.70	252
LNB+FGR	3.51	2.59	1.84	1.10	2.26	1.93	1.43	1.01	0.607	1.24	352
ULNB	3.51	2.59	1.84	1.10	2.26	2.63	1.95	1.38	0.828	1.70	166
FGD	6.57	4.86	3.45	2.07	4.24	5.92	4.38	3.11	1.86	3.82	152

6. Summary and Conclusions

This study has analyzed several possible control strategies intended to improve visibility in four northern-Midwest Class I areas. These are the Boundary Waters Canoe Area Wilderness, Voyageurs National Park, Isle Royale National Park, and the Seney Wilderness Area. Potential control strategies were evaluated for two geographic regions, a 3-state region and a 9-state region. As shown in Figure 6-1, the 3-state region includes Michigan, Minnesota, and Wisconsin, which are the three states immediately surrounding the northern-Midwest Class I areas. The 9-state region includes these three states and adds six surrounding states – North and South Dakota, Iowa, Missouri, Illinois, and Indiana.

The potential control strategies would address priority pollutants and emission sources which have been identified in previous modeling efforts by the MRPO and the Midwest States as significant contributors to visibility impairment in the region. Control strategies for the following emissions and emission source categories have been evaluated:

- SO_2 and NO_X emissions from electric generating units (EGUs)
- SO_2 and NO_X emissions from Industrial, commercial and institutional (ICI) boilers
- NO_X emissions from reciprocating engines and turbines
- Ammonia from agricultural operations
- NO_X emissions from onroad and nonroad mobile sources

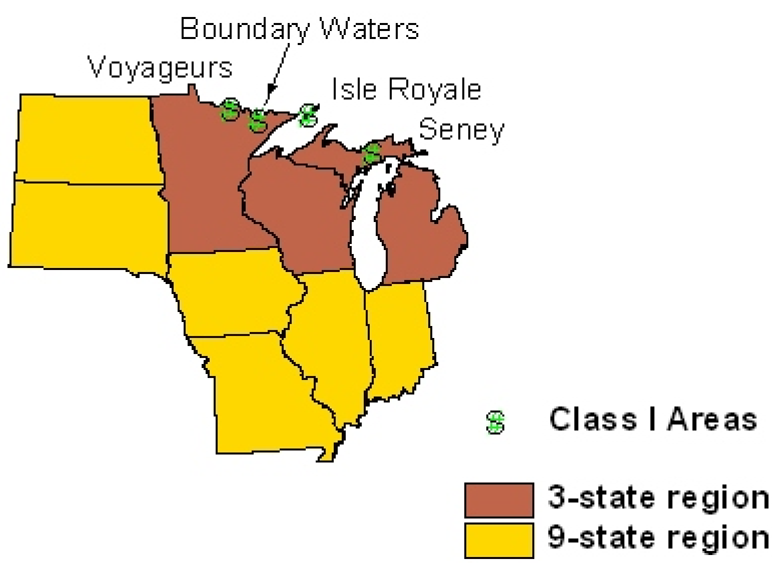

Figure 6-1. Geographic regions for the factor analysis.

The impacts of on-the-books and on-the-way Federal regulatory programs impacting these priority sectors have been analyzed. These programs include the following:

- Clean Air Interstate Rule (CAIR)[a]
- BART for available states (Michigan, Minnesota, Wisconsin, and North Dakota)
- Maximum Achievable Control Technology (MACT) standards for combustion turbines and industrial boilers
- On-road mobile source programs (i.e., 2007 Highway Diesel Rule, Tier II emission standards, and low sulfur gasoline standards)
- Non-road mobile source programs (i.e., Non-road Diesel Rule, Control of Emissions from Unregulated Non-road Engines, and the Locomotive/Marine Advance Notice of Proposed Rulemaking)

The on-the-books analysis serves both to (1) assess progress toward the reasonable further progress goal with existing control measures, and (2) provide a frame of reference for estimating the amounts of emissions available for additional control.

Figure 6-2 illustrates the visibility improvements expected with on-the-books control measures for the four northern-Midwest Class I areas. The figure shows the projected impacts of existing control measures in 2009, 2012, and 2018 (blue circles), based on CAMx modeling studies performed by the MRPO. These projected impacts of on-the-books measures are superimposed on a line representing the target glide path to natural visibility conditions. Figure 6-2 shows that the on-the-books control measures give some improvement over baseline conditions (in 2002), but fall short of achieving the glide path.

Table 6-1 describes the potential emission control strategies which have been evaluated for improving visibility in the northern-Midwest Class I areas. The following subsections summarize the estimated impacts of these candidate control strategies. The subsections address each of the four regional haze progress factors: cost, time required for compliance, energy and other environmental impacts, and the impact of remaining equipment life. The final subsection analyzes the impacts of the potential control measures on visibility, and summarizes the cost-effectiveness of these measures in terms of visibility improvement.

6.1 Factor 1 – Costs

Table 6.1-1 gives estimated average cost-effectiveness values (in terms of the cost per ton of emissions reduced) for potential control strategies for priority emission sources categories. The table also shows estimated cost effectiveness values for controlling the selected individual facilities outside of priority source categories. For comparison, Table 6.1-2 shows cost-effectiveness estimates previously published for different on-the-books control programs.

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[a] The EGU projections used in this study are taken from the VISTAS 2.1.9 version of IPM, which was developed in July 2005. In January 2007, EPA prepared new EGU projections (i.e., 3.0 version of IPM). The new EGU projections reflect lower 2018 SO_2 emissions for the 3-state region (about 500 TPD less). The MRPO is currently updating its regional modeling inventory to reflect a more current base year (2005) and improved future year emission estimates, including use of the new EGU projections. The new inventory will be available in mid-2007.

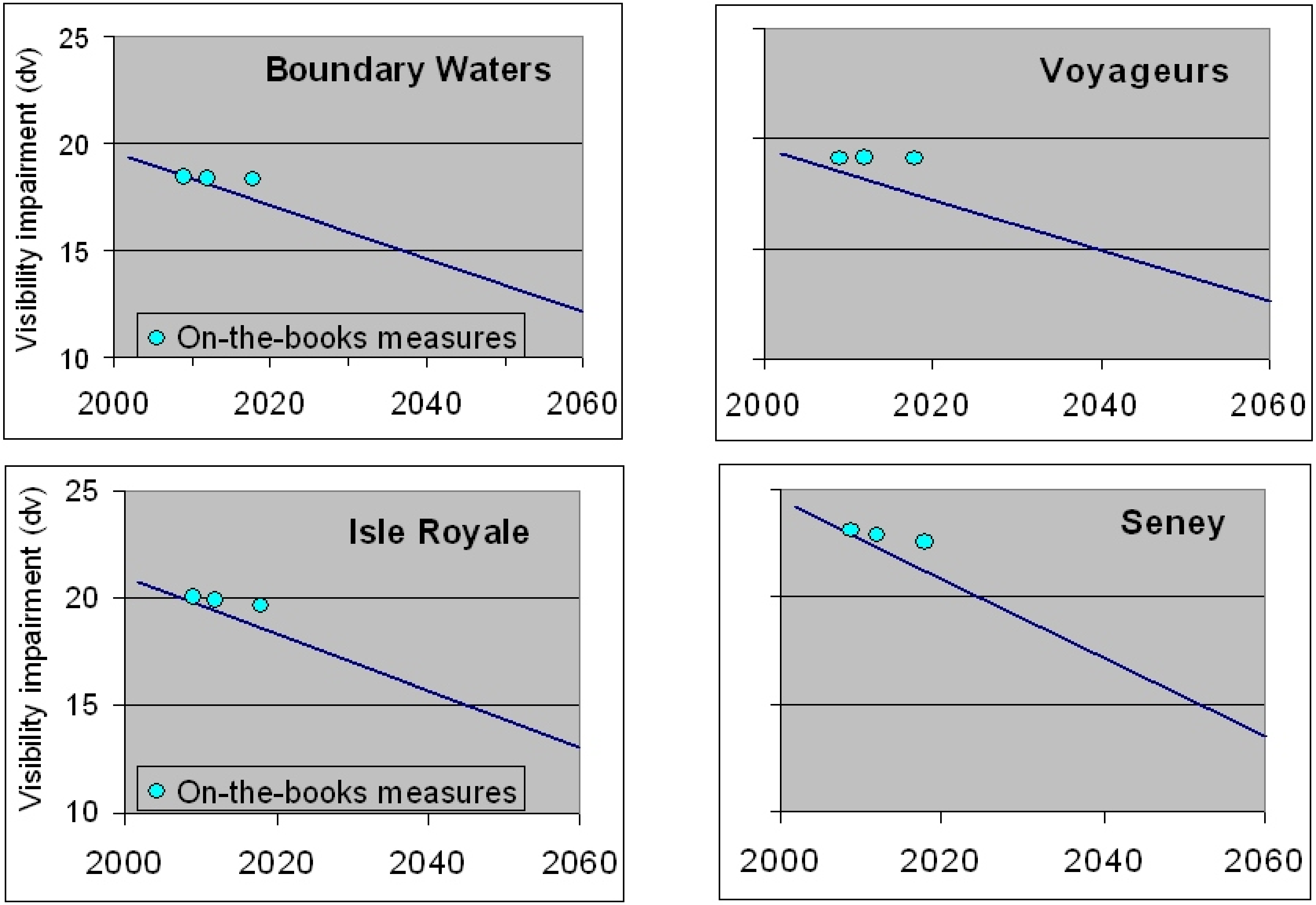

Figure 6-2. Estimated visibility impacts of on-the-books controls in comparison with reasonable progress goals for the northern-Midwest Class I areas.

Table 6-1. Summary of Candidate Future Control Measures Evaluated for Regional Haze

Emission category	Control strategy	Description
EGU	EGU1	SO2 limited to 0.15 lb/MM-BTU NOX limited to 0.10 lb/MM-BTU
	EGU2	SO2 limited to 0.10 lb/MM-BTU NOX limited to 0.07 lb/MM-BTU
ICI boilers	ICI1	40% SO2 reduction from 2018 baseline emissions 60% NOX reduction from 2018 baseline emissions
	ICI Workgroup	77% SO2 reduction from 2018 baseline emissions 70% NOX reduction from 2018 baseline emissions
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or more	89% NOX reduction from 2018 baseline emissions
	Turbines emitting 100 tons/year or more	84% NOX reduction from 2018 baseline emissions
	Reciprocating engines emitting 10 tons/year or more	89% NOX reduction from 2018 baseline emissions
	Turbines emitting 10 tons/year or more	84% NOX reduction from 2018 baseline emissions
Agricultural sources	Achieve a 10-15% NH3 reduction through the use of a variety of best management	
Mobile sources	Low-NOX Reflash	Install low-NOX software to counteract advanced computer controls installed on MY 1993-1998 HDDV that increase NOX emissions
	Midwest Clean Diesel Initiative (MCDI)	A collaborative organization between federal, state, and local agencies funding projects that will reduce diesel emissions through operational changes, technological improvements, and cleaner fuels
	Anti-Idling	Strategies to reduce NOX emissions that take the form of enforced shutdown policies, auxiliary power units (APUs), automatic engine shut-off technology, and truck stop electrification (TSE).
	Cetane Additive Program	Introduces additives to diesel fuel at the distribution source to increase the cetane number to approximately 50.
Cement Plants	Process Modification	Fuel switching, CEMStar (a process that introduces steel slag into the rotary kiln, lowering the temperature necessary to produce clinker)
	Conversion to dry kiln	
	LoTox™	Lower temperature oxidation technology

Table 6-1. Summary of Candidate Future Control Measures Evaluated for Regional Haze (continued)

Glass Manufacturing	LNB	Low-NOX Burner
	Oxy-firing	Process that uses oxygen and CO2 to combust with fuel instead of air
	Electric boost	Electricity currents are added to the gas to aid in combustion in the furnace
	SCR	Selective catalytic reduction
	SNCR	Selective non-catalytic reduction
Lime Manufacturing	Mid-kiln firing	A form of staged combustion of fuels in which a specially designed fuel injection system introduces a second fuel source at a midpoint in the kiln.
	LNB	Low-NOX Burner
	SNCR	Selective non-catalytic reduction
	SCR	Selective catalytic reduction
	FGD	Flue Gas Desulfurization
Oil Refinery	LNB	Low-NOX Burner
	SNCR	Selective non-catalytic reduction
	SCR	Selective catalytic reduction
	LNB+FGR	Low-NOX Burner with Flue Gas Recirculation
	ULNB	Ultra Low-NOX Burner
	FGD	Flue Gas Desulfurization

Table 6.1-1. Estimated Cost Effectiveness for Potential Control Measures in Terms of Emission Reductions

			Average Cost effectiveness ($/ton)		
Emission category	Control strategy	Region	SO2	NOX	NH3
EGU	EGU1	3-State	1,540	2,037	
		9-State	1,743	1,782	
	EGU2	3-State	1,775	3,016	
		9-State	1,952	2,984	
ICI boilers	ICI1	3-State	2,992	2,537	
		9-State	2,275	1,899	
	ICI Workgroup	3-State	2,731	3,814	
		9-State	2,743	2,311	
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or	3-State		538	
		9-State		506	
	Turbines emitting 100 tons/year or more	3-State		754	
		9-State		754	
	Reciprocating engines emitting 10 tons/year or more	3-State		1,286	
		9-State		1,023	
	Turbines emitting 10 tons/year or more	3-State		800	
		9-State		819	
Agricultural sources	10% reduction	3-State			31 - 2,700
		9-State			31 - 2,700
	15% reduction	3-State			31 - 2,700
		9-State			31 - 2,700
Mobile sources	Low-NOX Reflash	3-State		241	
		9-State		241	
	MCDI	3-State		10,697	
		9-State		2,408	
	Anti-Idling	3-State		(430) - 1,700	
		9-State		(430) - 1,700	
	Cetane Additive Program	3-State		4,119	
		9-State		4,119	
Cement Plants	Process Modification	Michigan		-	
	Conversion to dry kiln	Michigan		9,848	
	LoTox™	Michigan		1,399	
Glass Manufacturing	LNB	Wisconsin		1,041	
	Oxy-firing	Wisconsin		2,833	
	Electric boost	Wisconsin		3,426	
	SCR	Wisconsin		1,054	
	SNCR	Wisconsin		1,094	
Lime Manufacturing	Mid-kiln firing	Wisconsin		688	
	LNB	Wisconsin		837	
	SNCR	Wisconsin		1,210	
	SCR	Wisconsin		5,037	
	FGD	Wisconsin		128 - 4,828	
Oil Refinery	LNB	Wisconsin		3,288	
	SNCR	Wisconsin		4,260	
	SCR	Wisconsin		17,997	
	LNB+FGR	Wisconsin		4,768	
	ULNB	Wisconsin		2,242	
	FGD	Wisconsin		1,078	

Most of the projected cost-effectiveness values for potential additional controls (Table 6.1-1) are within the range of cost-effectiveness values estimated for on-the-books controls (Table 6.1-2). Cost-effectiveness values for additional EGU controls are somewhat higher than those estimated for the CAIR program. This is to be expected, since the EGU controls require emission reductions beyond those projected for CAIR in the Midwest region. ICI control measures are estimated to be somewhat more expensive than EGU control measures per ton of emission reduction.

Table 6.1-2. Estimated Cost-effectiveness of On-the-Books Programs

Control Program	Cost-effectiveness ($/ton)	
	SO_2	NO_X
CAIR	720–1,200	1,400–2,600
BART	300–963	248–1,770
MACT	1,500	7,600
Onroad mobile source programs		1,300–2,300
Nonroad mobile source programs		(1,000)–1,000

Emission controls for reciprocating engines and turbines are comparably cost-effective, especially for sources emitting 100 tons/year or more of NO_X. However, overall potential emission reductions for these sources (in terms of tons per year) are considerably less than the potential emission reductions for EGUs and ICI boilers.

The cost-effectiveness estimates for reducing ammonia emissions from agricultural operations cover a wide range. This range results from uncertainties in the effectiveness of one potential control measure, which is the planting of trees to absorb ammonia emissions from animal houses and other strong sources of emissions. A four-year measurement study has indicated that trees can be effective for removing ammonia, but the measured effectiveness varied widely during the course of the study.

Cost-effectiveness estimates for mobile source programs also vary widely depending on the specific program. Some programs, such as anti-idling measures, programs are very cost-effective for reducing NO_X emissions, even showing a potential cost savings. It must be noted that all of the mobile source control programs are designed to control other pollutants in addition to NO_X. In fact, the cetane additive program and the Midwest Control Diesel Initiative are focused on reducing primary emissions of diesel particulate matter, and reduce NO_X emissions as a collateral benefit. Therefore, the costs of these programs should not be judged on the basis of cost-effectiveness values for NO_X alone.

Analyses of selected individual analyses in the lime manufacturing facilities, cement, petroleum refining, and glass manufacturing industries indicated that control options generally are available within the same cost-effectiveness range found for the priority emission source categories included this analysis. Comparison of different cost models in some Individual facility analyses indicated that control cost estimates for any particular facility can vary by at least a factor of 2.

It must also be noted that the health benefits of reducing SO_2 and NO_X emissions are generally expected to outweigh the costs of control (as discussed in Section 6.3). These health benefits stem from the reduced ambient levels of $PM_{2.5}$ and ozone which would result from the control of SO_2 and NO_X.

6.2 Factor 2 – Time Necessary for Compliance

Table 6.2-1 summarizes the estimated time required for sources to comply with the potential regional haze control measures. As the Table shows, all of the control measures can be attained by 2018. It must be noted that if tree plantings are used to reduce ammonia emissions, these trees would require up to 10 years to grow, depending on the size of trees planted. Larger trees would take less time to have a significant impact on ammonia emissions, but would cost up to 6 times as much as small plants.

6.3 Factor 3 – Energy and Other Impacts

Table 6.3-1 summarizes the estimated energy, solid waste, and wastewater impacts for the candidate future regional haze control measures. The table also shows estimated increases in carbon dioxide emissions which would result from the implementation of these control measures. This increased CO_2 stems from the generation of electricity and steam to meet the needs of add-on control devices such as scrubbers and SCR. In addition, CO_2 is generated as a byproduct of most SO_2 control systems, either in the reaction of SO_2 with limestone or in the production of lime to absorb SO_2.

The energy and other environmental impacts of the potential control measures are believed to be manageable. For instance, the largest energy demand is the electricity and steam requirement for EGU control measures. This increased energy demand would be less than 1% of the total electricity and steam production of EGUs in the region. Solid waste disposal and wastewater treatment costs are expected to be less than 5% of the total operating costs of pollution control equipment. Wastewater is generally expected to be treated in existing wastewater treatment facilities at the affected emission sources.

The SO_2, NO_X, and ammonia controls would have beneficial environmental impacts by reducing acid deposition and nitrogen deposition to water bodies and natural landscapes. Reductions in these gaseous pollutants for regional are designed to reduce formation of fine particles that impair visibility. Such reductions would also result in decreases in the ambient levels of $PM_{2.5}$, with corresponding health benefits. In addition, broad regional reductions in NO_X would result in reductions in background levels of ambient ozone. These reductions in $PM_{2.5}$ and ozone will reduce levels of these pollutants in urban areas, and improve the potential for urban areas in the Midwest and Northeast to attain the National Ambient Air Quality Standards (NAAQS).

Table 6.2-1. Estimated Time Required for Compliance with Potential Control Measures

	Time Necessary for Compliance (years)		
Emission category	SO2	NOX	NH3
EGU (all strategies)	6.5	5.5	
ICI boilers (all strategies)	6.5	5.5	
Reciprocating engines and turbines		5.5 - 6.5	
Agricultural sources			
Trees			3-10
Other strategies			<1
Mobile sources			
Low-NOX		4	
MCDI		ongoing	
Anti-Idling		1.6-5	
Cetane		2	
Cement Plants	5	5	
Glass Manufacturing	3	3	
Lime Manufacturing	5.5	5.5	
Oil Refinery	6	6	

Table 6-3.1. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures

Emission category	Control strategy	Region	Pollutant	Emission reduction (1000 tons/year)	Additional electricity requirements (GW-hrs /year)	Additional diesel fuel requirements (1000 gal/year)	Steam require-ments (1000 tons/yr)	Solid waste produced (1000 tons/year)	Wastewater produced (1000 gallons /year)	Additional CO2 emitted (1000 tons/year)
EGU	EGU1	3-State	SO2	466	706	-	510	-	192	1,059
			NOX	71	40	-	17	-	0	42
		9-State	SO2	1,279	2,649	-	3,462	-	1,128	3,651
			NOX	224	110	-	46	-	0	115
	EGU2	3-State	SO2	532	1,106	-	1,722	-	237	1,523
			NOX	106	174	-	73	-	0	181
		9-State	SO2	1,455	3,504	-	5,439	-	1,919	4,666
			NOX	328	608	-	255	-	0	636
ICI boilers	ICI1	3-State	SO2	33	13	-	-	120	-	35
			NOX	22	37	-	5	0	-	38
		9-State	SO2	105	37	-	-	346	-	102
			NOX	73	214	-	12	1	-	217
	ICI Workgroup	3-State	SO2	53	20	-	-	186	-	55
			NOX	29	53	-	6	1	-	55
		9-State	SO2	169	58	-	-	537	-	158
			NOX	85	235	-	14	1	-	239
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or more	3-State	NOX	-	Not significant, the most cost effective control technology consists of low-NOx combustion technologies.					
		9-State	NOX	-	Not significant, the most cost effective control technology consists of low-NOx combustion technologies.					
	Turbines emitting 100 tons/year or more	3-State	NOX	-	Not significant, the most cost effective control technology consists of low-NOx combustion technologies.					
		9-State	NOX	-	Not significant, the most cost effective control technology consists of low-NOx combustion technologies.					
	Reciprocating engines emitting 10 tons/year or more	3-State	NOX	-	Not significant, the most cost effective control technology consists of low-NOx combustion technologies.					
		9-State	NOX	-	Not significant, the most cost effective control technology consists of low-NOx combustion technologies.					
	Turbines emitting 10 tons/year or more	3-State	NOX	-	Not significant, the most cost effective control technology consists of low-NOx combustion technologies.					
		9-State	NOX	-	Not significant, the most cost effective control technology consists of low-NOx combustion technologies.					

Table 6-3.1. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures (continued)

Agricultural sources	10% reduction	3-State	NH3	27	-	6 - 13	-	-	-	55 - 118
		9-State	NH3	91	-	19 - 42	-	-	-	183 - 392
	15% reduction	3-State	NH3	41	-	9 - 19	-	-	-	82 - 177
		9-State	NH3	137	-	29 - 63	-	-	-	274 - 589
Mobile sources	Low-NOX Reflash	3-State	NOX	-	No other environmental impacts.					
		9-State	NOX	-	No other environmental impacts.					
	MCDI	3-State	NOX	-	Anti-idling strategies have no quantifiable environmental impacts. Biodiesel					
		9-State	NOX	-	productions results in a 79% reduction in wastewater and a 96% reduction in solid waste					
	Anti-Idling	3-State	NOX	-	No other environmental impacts					
		9-State	NOX	-	No other environmental impacts					
	Cetane Additive Program	3-State	NOX	-	No other environmental impacts					
		9-State	NOX	-	No other environmental impacts					

The MRPO carried out a previous modeling effort to evaluate the benefits of implementing the EGU emission caps for SO_2 and NO_X over the five-state MRPO region. In this study, the CAMx model was used to estimate reductions in ambient levels of $PM_{2.5}$ and ozone as a result of SO_2 and NO_X emission reductions. The EPA Environmental Benefits Mapping and Analysis Program (BenMAP) was used to quantify health benefits. These benefits would occur not just in the region where emissions limitations are implemented, but also in areas downwind of this region.

The earlier benefits study provides an indication of the magnitudes of health benefits in comparison to costs. When benefits in the entire modeling domain were considered, the estimated values of these benefits outweighed the projected costs of control by more than a factor of 10. When only benefits in the MRPO were considered, the predicted benefit values exceeded estimated costs by a factor of 6.

6.4 Factor 4 – Remaining Equipment Life

Most of the control strategies evaluated in this study for regional haze are market-based caps to be applied to a broad geographic region. It is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for most control measures. In addition, large emission sources such as EGUs and ICI boilers generally have no set equipment life. In fact, many units have been refurbished multiple times. In the Midwest region, more than 150 units are more than 60 years old, and some units are more than 80 years old.

6.5 Factor 5 – Visibility Impacts

Table 6.5-1 shows the estimated incremental improvements that would be needed beyond the impacts of on-the-books controls in 2018 in order to achieve the glide path natural visibility at the four northern-Midwest Class I areas. Table 6.5-2 presents the estimated visibility impacts of potential control strategies for the priority emission source categories. (Light extinction values have not been modeled for the selected individual facilities outside the priority emission source categories.) Because of the non-linear relationship between light extinction and deciviews (see Section 3-5), the visibility improvement values in Table 6.5-2 are not strictly additive. However, in these ranges – visibility improvements of 1 deciview or less with a baseline of about 20 – the values can be added with only a small error (<1%).

Table 6.5-3 summarizes the average visibility impacts and cost-effectiveness information for the potential control strategies. Cost-effectiveness values are given in terms of the cost per pollutant reduction and also the cost per unit of visibility improvement. Figure 6.5-1 illustrates the estimated impacts of potential regional haze strategies in relation to the impacts of on-the-book control measures, and in relation to the glide path to natural visibility conditions.

Table 6.5-1. Comparison of Visibility Goals in 2018 with Projected Impacts for On-the-Books Controls

Pollutant	Estimated visibility impairment on the 20% worst-visibility days (deciviews)[a]			
	Boundary Waters	Voyageurs	Isle Royale	Seney
Baseline conditions (2000–2004)[a]	19.86	19.48	21.62	24.48
Projected conditions in 2018 with on-the-books controls[b]	18.94	19.18	20.04	22.38
Net change	0.92	0.30	1.58	2.10
Glide path goal for 2018	17.70	17.56	19.21	21.35

[a]The baseline condition values reflect the recent adjustments proposed by the Midwest RPO to include several missing days. The adjusted values are, on average, less than 0.5 deciviews greater than those provided on the IMPROVE website."
[b]Based on CAMx modeling by the MRPO. These modeling analyses used preliminary estimates of the impacts of BART controls, which are generally larger than the impacts estimated in industry BART analyses.

It must be noted that the estimates of visibility improvement are subject to considerable uncertainty. These are based on rollback calculations using the results of PSAT analyses and CAMx sensitivity analysis. These rollback calculations provide a mechanism for evaluating the relative impacts of different strategies. However, they may over-estimate or under-estimate the impacts of NH_3 or NO_X controls relative to SO_2 controls. More detailed modeling using CAMx or other photochemical models is needed to fully quantify the impact of any given control strategy.

A detailed analysis of cost per deciview for on-the-books control measures was beyond the scope of this project. However, the most of the measures in Table 6.5-3 are within the range of cost effectiveness values for on-the-books control measures.

Based on the cost-effectiveness estimates in Table 6.5-3, the least expensive control measure in terms of cost unit of per visibility improvement is the control of NO_X emissions from large reciprocating engines in the 3-state region. This measure is followed by the low-NO_X reflash measure for mobile sources. Some anti-idling measures (to reduce NO_X and diesel particulate matter) could result in cost savings; however, the overall control measure has a broad of potential cost effectiveness values for NO_X reductions. The visibility improvements calculated for all of these measures are small. The cost effectiveness of reducing ammonia from agricultural sources is very uncertain, but this measure may be comparably cost-effective (depending on the effectiveness of tree plantings for removing ammonia).

EGU and ICI boiler control measures have somewhat higher cost-per-deciview values than the above measures. However, the visibility impacts of these measures are much larger. In addition, costs of EGU and ICI measures per ton of emission reduction are within the range of values incurred for on-the-books control measures. Further, a previous benefits analysis for EGU control measures has indicated that the monetary health benefits from EGU controls outweigh the cost of control by a factor of 6 to 10 (depending on the geographic region covered in the health benefits analysis). The EGU1 limits for SO_2 in the 3-state region could be sufficient to reach the glide path line at Boundary Waters, Seney, and Isle Royale.

Additional control measures are expected to be needed to reach the glide path line for the Voyageurs Class I area. Based on MRPO modeling studies, the on-the-books control measures also have been less effective in improving visibility at Voyageurs than at the other northern-Midwest Class I areas. This appears to be due to differences in source region culpabilities. In particular, the influence from the major Midwest source regions, especially those with the largest change (decrease) in emissions, decreases with distance, i.e., the most impact occurs at Seney (the closest Class I area) and the least impact occurs at Voyageurs (the farthest Class I area).

Table 6.5-2. Estimated Visibility Impacts of Potential Control Strategies

Strategy and region				Estimated visibility improvement on the 20% worst-visibility days in 2018 (deciviews)				
				Boundary Waters	Voya-geurs	Isle Royale	Seney	Average
EGU	EGU1	3-State	SO2	0.30	0.12	0.44	0.41	0.32
			NOX	0.07	0.05	0.06	0.04	0.06
		9-State	SO2	0.77	0.35	0.84	1.01	0.74
			NOX	0.18	0.24	0.15	0.12	0.17
	EGU2	3-State	SO2	0.46	0.21	0.52	0.46	0.41
			NOX	0.12	0.08	0.09	0.07	0.09
		9-State	SO2	0.87	0.40	0.96	1.18	0.85
			NOX	0.26	0.30	0.23	0.19	0.24
ICI boilers	ICI1	3-State	SO2	0.065	0.035	0.067	0.055	0.055
			NOX	0.074	0.048	0.026	0.023	0.043
		9-State	SO2	0.090	0.047	0.092	0.109	0.084
			NOX	0.098	0.070	0.048	0.058	0.068
	ICI Workgroup	3-State	SO2	0.105	0.055	0.107	0.088	0.089
			NOX	0.095	0.061	0.034	0.030	0.055
		9-State	SO2	0.145	0.075	0.148	0.176	0.136
			NOX	0.114	0.082	0.056	0.067	0.080
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or more	3-State	NOX	0.027	0.017	0.009	0.008	0.015
		9-State	NOX	0.074	0.053	0.036	0.044	0.052
	Turbines emitting 100 tons/year or more	3-State	NOX	0.014	0.009	0.005	0.005	0.008
		9-State	NOX	0.010	0.007	0.005	0.006	0.007
	Reciprocating engines emitting 10 tons/year or more	3-State	NOX	0.064	0.041	0.023	0.020	0.037
		9-State	NOX	0.105	0.075	0.051	0.062	0.073
	Turbines emitting 10 tons/year or more	3-State	NOX	0.019	0.013	0.007	0.006	0.011
		9-State	NOX	0.017	0.012	0.008	0.010	0.012
Agricultural sources	10% reduction	3-State	NH3	0.09	0.11	0.10	0.10	0.10
		9-State	NH3	0.15	0.18	0.15	0.17	0.16
	15% reduction	3-State	NH3	0.14	0.17	0.15	0.14	0.15
		9-State	NH3	0.23	0.27	0.23	0.26	0.25
Mobile sources	Low-NOX Reflash	3-State	NOX	0.006	0.007	0.009	0.006	0.007
		9-State	NOX	0.008	0.009	0.012	0.012	0.010
	MCDI	3-State	NOX	0.015	0.019	0.014	0.013	0.015
		9-State	NOX	0.014	0.018	0.013	0.013	0.015
	Anti-Idling	3-State	NOX	0.008	0.011	0.008	0.008	0.009
		9-State	NOX	0.005	0.007	0.006	0.006	0.006
	Cetane Additive Program	3-State	NOX	0.009	0.011	0.009	0.008	0.009
		9-State	NOX	0.006	0.007	0.009	0.010	0.008

Table 6.5-3. Summary of Visibility Impactes and Cost Effectiveness of Potential Control Measures

Emission category	Control strategy	Region	Pollutant	Average estimated visibility improvement for the four Midwest Class I areas (deciviews)	Cost effectiveness ($/ton)	Cost effectiveness per visibility improvement ($million/ deciview)
EGU	EGU1	3-State	SO2	0.32	1,540	2,249
			NOX	0.06	2,037	2,585
		9-State	SO2	0.74	1,743	2,994
			NOX	0.17	1,782	2,332
	EGU2	3-State	SO2	0.41	1,775	2,281
			NOX	0.09	3,016	3,604
		9-State	SO2	0.85	1,952	3,336
			NOX	0.24	2,984	4,045
ICI boilers	ICI1	3-State	SO2	0.055	2,992	1,776
			NOX	0.043	2,537	1,327
		9-State	SO2	0.084	2,275	2,825
			NOX	0.068	1,899	2,034
	ICI Workgroup	3-State	SO2	0.089	2,731	1,618
			NOX	0.055	3,814	1,993
		9-State	SO2	0.136	2,743	3,397
			NOX	0.080	2,311	2,473
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or more	3-State	NOX	0.015	538	282
		9-State	NOX	0.052	506	542
	Turbines emitting 100 tons/year or more	3-State	NOX	0.008	754	395
		9-State	NOX	0.007	754	810
	Reciprocating engines emitting 10 tons/year or more	3-State	NOX	0.037	1,286	673
		9-State	NOX	0.073	1,023	1,095
	Turbines emitting 10 tons/year or more	3-State	NOX	0.011	800	419
		9-State	NOX	0.012	819	880
Agricultural sources	10% reduction	3-State	NH3	0.10	31 - 2,700	8 - 750
		9-State	NH3	0.16	31 - 2,700	18 - 1,500
	15% reduction	3-State	NH3	0.15	31 - 2,700	8 - 750
		9-State	NH3	0.25	31 - 2,700	18 - 1,500
Mobile sources	Low-NOX Reflash	3-State	NOX	0.007	241	516
		9-State	NOX	0.010	241	616
	MCDI	3-State	NOX	0.015	10,697	7,595
		9-State	NOX	0.015	2,408	4,146
	Anti-Idling	3-State	NOX	0.009	(430) - 1,700	(410) - 1,600
		9-State	NOX	0.006	(430) - 1,700	(410) - 1,600
	Cetane Additive Program	3-State	NOX	0.009	4,119	3,155
		9-State	NOX	0.008	4,119	10,553

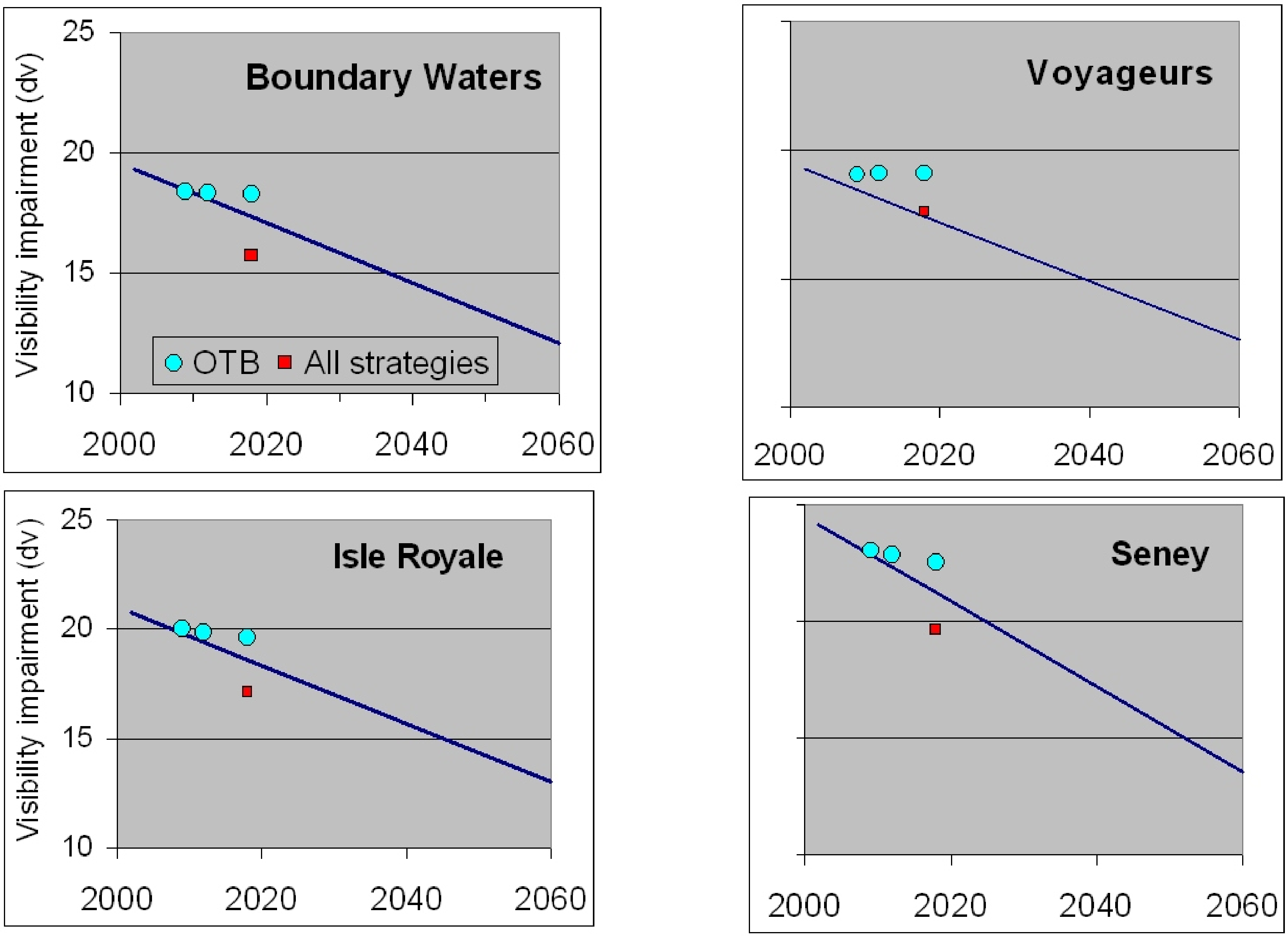

Figure 6-5-1. Estimated overall visibility impacts of control strategies in comparison with reasonable progress goals for the northern-Midwest Class I areas.

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Contents

Table A-1. Summary of Current and Projected Emissions in the for States in the Study Region

	Estimated missions (tons/day)									
	EGU	ICI boilers	Recipro-cating engines	Turbines	Other point	Area sources	Onroad mobile sources	Nonroad mobile sources	Marine, aircraft, railroad	Total
SO2 in 2002										
Michigan	1,103	55			107	71		19	1	1,355
Minnesota	318	23			36	33		19	8	437
Wisconsin	602	149			14	9		13	13	800
3-State Subtotal	2,023	227			156	113		51	21	2,592
Illinois	1,310	161			213	11		31	0	1,725
Indiana	2,499	148			144	158		17	0	2,966
Iowa	412	88			50	2		12	8	571
Missouri	835	28			227	117		12	12	1,231
North Dakota	376	21			22	142		0	3	564
South Dakota	35	1			3	50		0	1	90
9-State Total	7,489	676			813	594		123	44	9,739
NOX in 2002										
Michigan	448	45	44	11	116	49	926	205	114	1,959
Minnesota	271	26	18	6	117	126	455	208	100	1,327
Wisconsin	294	65	8	2	24	32	481	145	79	1,129
3-State Subtotal	1,013	136	71	19	256	208	1,862	557	294	4,416
Illinois	712	101	112	14	129	62	890	324	277	2,622
Indiana	830	105	25	2	106	63	703	178	123	2,133
Iowa	254	45	26	2	39	7	304	174	89	941
Missouri	458	12	21	3	63	64	602	199	133	1,555
North Dakota	196	14	9	1	7	45	75	2	46	395
South Dakota	44	1	0	1	14	14	92	2	8	176
9-State Total	3,507	413	264	42	616	462	4,529	1,437	969	12,239
SO2 in 2018										
Michigan	1,093	51			134	68		0	1	1,347
Minnesota	236	22			48	34		4	2	346
Wisconsin	426	142			15	10		0	9	601
3-State Subtotal	1,755	215			196	112		4	11	2,294
Illinois	661	155			94	13		0	0	923
Indiana	1,033	138			152	153		3	0	1,479
Iowa	404	83			74	3		1	2	567
Missouri	770	26			395	120		3	7	1,321
North Dakota	298	20			32	137		4	0	491
South Dakota	33	2			4	51		3	0	94
9-State Total	4,952	641			948	588		19	20	7,168
NOX in 2018										
Michigan	273	43	41	11	133	54	385	94	110	1,145
Minnesota	115	25	18	6	134	136	205	175	54	867
Wisconsin	126	64	7	2	21	35	118	69	57	500
3-State Subtotal	514	132	66	20	287	225	708	338	222	2,512
Illinois	199	96	111	16	121	73	176	154	186	1,131
Indiana	262	100	23	2	101	69	105	141	84	887
Iowa	140	44	25	2	50	9	67	141	47	525
Missouri	213	12	20	3	75	74	119	161	99	777
North Dakota	196	14	8	1	12	50	34	204	24	545
South Dakota	40	1	0	1	22	15	42	148	5	273
9-State Total	1,564	400	254	45	669	515	1,250	1,288	666	6,650

Table A-2. Estimated Cost of Control for Facilities Subject to BART*

State	Source name	County	Baseline emissions (tons/year) SO2	Baseline emissions (tons/year) NOX	Estimated reductions (%) SO2	Estimated reductions (%) NOX	Total annualized cost ($1000/year) SO2	Total annualized cost ($1000/year) NOX	Cost effectiveness ($/ton) SO2	Cost effectiveness ($/ton) NOX
Minnesota	Ipsat Inland (Mittal)	St. Louis	155	3,254	a	a	a	a	a	a
	EVTAC-Fairlane (United Taconite)	St. Louis	3,222	1,771	a	a	a	a	a	a
	National Steel (USS Keetac)	St. Louis	704	6,049	34	a	a	a	a	a
	Hibbing Taconite	St. Louis	593	6,203	0	13	a	a	a	a
	USS Minntac	St. Louis	1,946	14,924	0	10	a	612	a	705
	Northshore Mining^	Lake	2,291	3,649	0	40	a	640	a	1,439
North Dakota	Great River Energy – Coal Creek	McLean	34,578	11,114	78	30	7,870	420	531	248
	Basin Electric Power – Leland Olds	Mercer	88,462	16,136	93	44	49,000	9,300	963	1,770
	Great River Energy – Stanton	Mercer	8,592	2,139	90	26	9,330	1,275	300	504
	Minnkota Power – MR Young	Oliver	b	b	84	62	b	18,877	b	1,248

* Other State's BART analyses are not listed as they had not yet been completed at the time of this report

a The facility proposed that existing controls and operations were BART and therefore cost estimates are not included

b Information not available in facility's BART analysis

^ The facility proposed additional control as BART only for the power boiler at the facility, not the indurating furnaces. The power boiler is a CAIR unit

Table A-3. Projected Emission Reductions from EGUs as a Result of CAIR and Other Existing Regulations

	Baseline and projected emissions from EGU (1000 tons/year)				Emission reductions from 2002 (%)		
	2002	2012	2018	2026	2012	2018	2026
SO2 emissions							
Michigan	403	398	399	185	1	1	54
Minnesota	116	86	86	73	26	26	37
Wisconsin	220	153	155	137	31	29	38
3-state total	739	636	641	395	14	13	47
Illinois	478	239	241	214	50	50	55
Indiana	912	462	377	336	49	59	63
Iowa	150	144	147	146	4	2	3
Missouri	305	281	281	224	8	8	27
North Dakota	137	108	109	91	21	21	34
South Dakota	13	12	12	12	5	5	3
Region total	2,734	1,883	1,808	1,418	31	34	48
NOX emissions							
Michigan	164	91	100	93	45	39	43
Minnesota	99	41	42	43	58	58	57
Wisconsin	107	44	46	47	59	57	56
3-state total	370	176	188	182	52	49	51
Illinois	260	73	73	68	72	72	74
Indiana	303	141	95	93	54	68	69
Iowa	93	49	51	51	47	45	45
Missouri	167	81	78	75	52	53	55
North Dakota	72	72	72	72	0	0	0
South Dakota	16	15	15	15	9	9	8
Region total	1,280	606	571	556	53	55	57

Appendix B
Potential SO_2 and NO_X Regional Control Strategies and Unit-level Control Technologies

Contents

Appendix B-1. Control Strategies for Mobile Sources

Technology	Processes Covered	Estimated NOX Control Efficiency	Notes	Reference
Low NOX Calibration/Reflashing. Adopt regulations similar to the CARB Low NOx Software Upgrade program with a set phase in schedule that would require all low NOx rebuild engines to have low NOx rebuild kit installed by 2009.	1993 to 1998 MHDDV	24% reduction in tailpipe emissions	a	1, 2
	1993 to 1998 HHDDV	24% reduction in tailpipe emissions	a	1, 2
Emissions Inspections Program. Implement a State emissions inspection program for passenger vehicles and heavy duty diesel trucks.	1995 and older enhanced IM tailpipe test	8-9% annual inventory reduction	b, c	3
	1996 and newer OBDII equipped gasoline vehicles	0.1 gram/mile reduction for post-repair vehicles	b	4
	1997 and newer OBDII equipped light-duty diesel vehicles	0.6% reduction in tailpipe emissions	b	5
	2007 and newer heavy-duty diesel trucks (on the books)			6
	Smoking vehicles (identification, repair, and/or replace)	up to 53% decrease in NOX emissions for all vehicles participating in the program	aa	1, 21
Alternative Fuels. Increase use of alternative fuels including biodiesel-petroleum diesel blends, ethanol-gasoline blends, and liquid or compressed natural gas. (*Recommendation may be restricted to fuels already available in the Petroleum Administration for Defense District.)				
Use 7.0 RVP fuel in urban areas; e.g., Detroit area	LDGV			26
Fuel Switching: Biodiesel B100	HDDV	+10% pre-1998, +30% 98-04 increase in tailpipe emissions	d	7
Fuel Switching: Biodiesel B20	HDDV	+2% pre-1998, +4% 98-04 increase in tailpipe emissions	e	7

Appendix B-1. Control Strategies for Mobile Sources

Technology	Processes Covered	Estimated NOX Control Efficiency	Notes	Reference
Fuel Switching: Biodiesel B20	Bulldozer, Motor Grader	unknown	f	8
Fuel Switching: Biodiesel B30	Bulldozer, Motor Grader	unknown	g	8
Fuel Switching: Biodiesel B20	Locomotive (line haul or switching)	+5-6% increase in tailpipe emissions	h	9
Fuel Switching: Biodiesel B20	Marine Port applications	unknown	i	10
Use lower sulfur fuel: CARB Diesel*	Locomotive (line haul or switching)	1-2% reduction in tailpipe emissions	h, j	9
	Harbor craft	15% inventory reduction	k	18
	Large deep draft marine vessels	15% inventory reduction	k	18
Use lower sulfur fuel: Highway or ULSD*	Harbor craft (ferries, tugs)	15% inventory reduction	k	18
	Large deep draft marine vessels	15% inventory reduction	k	18
Increase use of E10	LDGV	+5% increase in tailpipe emissions	l	11, 12
Fuel Switching: Convert public fleets to Flex Fuel Vehicles fueled with E85.	LDGV	tailpipe control efficiency unavailable	l	12
Fuel Switching: LNG or CNG	LDGV	60% reduction in tailpipe emissions		13
Fuel Switching: LNG	Locomotive (line haul or switching)	tailpipe control efficiency unavailable		14
Fuel Switching: LNG or CNG	MDGV, HDGV	50% reduction in tailpipe emissions		13
Anti-Idling. Reduce idling emissions from heavy-duty diesel trucks and locomotives using truck stop electrification and locomotive anti-idling technology.	1993 to 1998 MHDDV	unknown	m, n	1
	Switching locomotives	50% reduction in tailpipe emissions	o	1
	Line-haul locomotives	75% reduction in tailpipe emissions	o	1

[continued]

Appendix B-1. Control Strategies for Mobile Sources

Technology	Processes Covered	Estimated NOX Control Efficiency	Notes	Reference
Fleet Modernization (all percentages are reductions in tailpipe emissions). Replace equipment or rebuild engines to meet new engine standards.				
Upgrade to 1990 Engine	MY 1989 and earlier HDDV	43% reduction	p	1
Upgrade to 2001/2 Engine	MY 1989 and earlier HDDV	63% reduction	p	1
	MY 1990 HDDV	33% reduction	p	1
	MY 1991-1997 HDDV	20% reduction	p	1
Upgrade to 2002/4 Engine	MY 1989 and earlier HDDV	78% reduction	p	1
	MY 1990 HDDV	66% reduction	p	1
	MY 1991-1997 HDDV	52% reduction	p	1
Upgrade to 2007 Engine	MY 1998-2001 HDDV	95% reduction	p	1
	MY 2002-2006 HDDV	92% reduction	p	1
Upgrade construction and agricultural equipment to Tier 2, 3, or 4	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks, Agricultural Tractors, Combines	Dependent on model year and horsepower. See Reference 11 for engine standard schematic.		1, 15
Fleet turnover to 2007 and newer engines (On the books)	HDDV	unknown		

[continued]

Appendix B-1. Control Strategies for Mobile Sources

Technology	Processes Covered	Estimated NOX Control Efficiency	Notes	Reference
Retrofit Technology (all percentages are reductions in tailpipe emissions). Install aftertreatment NOX controls on on-road heavy-duty diesel vehicles and off-road construction, cargo-handling, and marine equipment.				
Selective Catalytic Reduction (SCR)	MY pre-1989 through 2006 HDDV	up to 80% reduction		1, 16
	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	up to 80% reduction		1, 16
	Locomotive (line haul or switching)	90% reduction		16
	Agricultural Tractors, Combines	up to 80% reduction	q	1, 16
Lean NOX Catalyst (LNC) combined with Diesel Particulate Filter (DPF)	MY pre-1989 through 2006 HDDV	15-25% reduction	r	1, 16
LNC	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	15-25% reduction		1, 17
	Agricultural Tractors, Combines	15-25% reduction		1, 16
Exhaust Gas Recirculation (EGR) combined with DPF	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	up to 50% reduction	s	1, 16
	Agricultural Tractors, Combines	up to 50% reduction	s	1, 16
Diesel Oxidation Catalyst combined with SCR	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	up to 80% reduction	t	1, 16
	Agricultural Tractors, Combines	up to 80% reduction	t	1, 16
SCR combined with DPF	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	up to 80% reduction	u	1, 16
	Agricultural Tractors, Combines	up to 80% reduction	u	1, 16

[continued]

Appendix B-2. Control Strategies for EGUs

Technology	Processes Covered	Efficiency of Control	Notes	Reference
Baseline and On-the-books regional programs				
Baseline 2002: (MRPO average SO2 is 1.16 lbs/mmBtu, NOx is 0.43 lbs/mmBtu): NSPS; PSD/NSR; State RACT Rules; Title IV SO2 Program	EGUs	MRPO average SO2 is 1.16 lbs/mmBtu, NOx is 0.43 lbs/mmBtu	bb	19
2009 On-the-Books measures: CAIR	EGUs	EPA CAIR levels are estimated at 0.13 lbs/mmBtu NOX and 0.26 lbs/mmBtu SO2 in 2015.	bb	19, 22
2009 On-the-Books measures: CAIR -- Michigan Impacts	EGUs	EPA estimates a 10% reduction in SO2 and a 29% reduction in NOX from 2003 levels.	bb	23
2009 On-the-Books measures: CAIR -- Minnesota Impacts	EGUs	EPA estimates a 36% reduction in SO2 and a 59% reduction in NOX from 2003 levels.	bb	24
2009 On-the-Books measures: CAIR -- Wisconsin Impacts	EGUs	EPA estimates a 32% reduction in SO2 and a 61% reduction in NOX from 2003 levels.	bb	25
Additional regional programs				
Adopt Emission Caps Based on “Retrofit SO2 BACT Level” of 0.15 lbs/mmBtu by 2013 (with Interim Cap Based on 0.36 lbs/mmBtu in 2009)	EGUs	Additional 0.11 lbs/mmBtu reduction in SO2 from original CAIR emissions cap	v	19
Adopt Emission Caps Based on “Retrofit NOx BACT Level” of 0.10 lbs/mmBtu by 2013 (with Interim Cap Based on 0.15 lbs/mmBtu in 2009)	EGUs	Additional 0.03 lbs/mmBtu reduction in NOX from original CAIR emissions cap		19
Adopt Emission Caps Based on “SO2 BACT Level for New Plants” of 0.10 lbs/mmBtu by 2013 (with Interim Cap Based on 0.24 lbs/mmBtu in 2009)	EGUs	Additional 0.16 lbs/mmBtu reduction in SO2 from original CAIR emissions cap	w	19
Adopt Emission Caps Based on “NOx BACT Level for New Plants” of 0.07 lbs/mmBtu by 2013 (with Interim Cap Based on 0.12 lbs/mmBtu in 2009)	EGUs	Additional 0.06 lbs/mmBtu reduction in NOX from original CAIR emissions cap		19
Replace old boilers to boost efficiency by 50-60%	EGUs	Not Available		19
Implement Consumer Education programs to promote energy efficiency and reduce demand.		Not Available		19

Appendix B-2. Control Strategies for EGUs

Technology	Processes Covered	Efficiency of Control	Notes	Reference
Fuel Options				
Use fuel oil with a sulfur content of 0.05% or less for all boiler sizes (<50 - >250 MmBtu/hr)	#1 and #2 fuel oil			26
Use fuel oil with a sulfur content of 0.5% or less	#4 and #6 fuel oil			26
Use coal with low sulfur content	Coal for units between 50-100 mmBtu/hr	2.0 lb/MmBtu or 30% SO2 reduction		26
Use coal with low sulfur content	Coal for units between 100-250 mmBtu/hr	1.2 lb/MmBtu or 85% SO2 reduction		26
Use coal with low sulfur content	Coal for units >250 MmBtu/hr	0.25 lb/MmBtu or 85% SO2 reduction		26
Retrofit Technologies for individual emission units				
Burner Modifications	Most units	10 to 30% NOx reduction		19
Fuel Reburn	Most units. Furnace height (residence time) may restrict some applications	20 to 30% NOx reduction for Fuel-Lean Gas Reburning (no OFA), and 30 to 60% reduction for conventional reburning.		19
Hydrocarbon-enhanced SNCR	Most units. Can use more NH3 with less slip.	40 to 60% NOx reduction		19
Low-NOx Burners	Most boilers already have LNB.	30 to 50% NOx reduction		19
Overfire Air	Most units. Furnace height may restrict some applications	20 to 40% NOx reduction		19
Oxygen-enhanced combustion modification	Best applied with new OFA system designed to achieve stoichiometric air-fuel ratio < 0.8.	30-50% beyond OFA		19
Rich Reagent Injection	Most units. Modeling required to determine injection locations.	20 to 30% additional NOx reduction beyond OFA.		19
Selective Catalytic Reduction (SCR)	Most units. Space availability may constrain some options. High sulfur fuels more challenging	70 to 90+% NOx reduction		19
Selective Non-catalytic Reduction (SNCR)	Most units. Residence time and temperature characteristics are important	25 to 50% NOx reduction, depending on the furnace temperature and time for reaction.		19

[continued]

Appendix B-2. Control Strategies for EGUs

Technology	Processes Covered	Efficiency of Control	Notes	Reference
Physical Coal Cleaning	Available for all units	10-40% SO2 reduction		19
Chemical Coal Cleaning	Available for all units	50-85% SO2 reduction		19
Switch to Low Sulfur Coal	Available for all units	50-80% SO2 reduction		19
Limestone forced oxidation system (LSFO)	Generally used for >100 MW units units firing high-sulfur (>2 percent) bituminous coals.	52 – 98% reduction in SO2, with median reduction of 90%; EPA used 95% in CAIR analysis		19
Magnesium enhanced lime system (MEL)	Generally used for 100-550 MW units units firing low-sulfur (<2 percent) bituminous, sub-bituminous, and lignite coals.	52 – 98% reduction in SO2, with median reduction of 90%; EPA used 96% for CAIR analysis		19
Lime spray dryer system (LSD)	Can be used for both low-and high-sulfur coals, depending on the economics of each application.	70 - 96% reduction in SO2, with median reduction of 90%; EPA used 90% for CAIR analysis		19
Dry or wet FGD	Coal-burning units >250 mmBtu/hr	90% SO2 reduction		26
Combustion Tuning	All units 50-100 mmBtu/hr	5-35% NOX reduction		26

[continued]

Appendix B-3. Control Strategies for ICI Boilers

Technology	Processes Covered	Efficiency of Control (% at the unit)	Notes	Reference
Baseline and On-the-books regional programs				
Baseline 2002: NSPS; PSD/NSR; State RACT Rules	ICI Boilers	NA	bb	20
2009 On-the-Books (OTB) measures: Enforcement settlements and Alcoa announced scrubbers	ICI Boilers	18% SO2 reduction from 2002 levels	bb	20
2009 OTB measures: NOx SIP Call for large boilers, enforcement settlements	ICI Boilers	3% NOX reduction from 2002 levels	bb	20
Additional regional programs				
OTB measures plus 40% SO2 Reduction and 60% Reduction (similar to NOx SIP Call) to All Medium and Large ICI Boilers	ICI Boilers	29% SO2 reduction and 19% NOX reduction from 2002 levels	x	20
OTB Measures plus Likely Controls to ICI Boilers subject to the proposed BART requirements Emission Reductions.	ICI Boilers	8% NOX reduction and 40% SO2 reduction from 2002 levels	y	20
OTB Measures plus 90% SO2 Reduction and 80% NOX reduction (similar to BART) to All Medium and Large ICI Boilers Emission Reductions.	ICI Boilers	66% SO2 reduction and 31% NOX reduction from 2002 levels	z	20
Fuel Options				
Use fuel oil with a sulfur content of 0.05% or less for all boiler sizes (<50 - >250 MmBtu/hr)	#1 and #2 fuel oil			26
Use fuel oil with a sulfur content of 0.5% or less	#4 and #6 fuel oil			26
Use coal with low sulfur content	Coal for units between 50-100 mmBtu/hr	2.0 lb/MmBtu or 30% SO2 reduction		26
Use coal with low sulfur content	Coal for units between 100-250 mmBtu/hr	1.2 lb/MmBtu or 85% SO2 reduction		26
Use coal with low sulfur content	Coal for units >250 MmBtu/hr	0.25 lb/MmBtu or 85% SO2 reduction		26

Appendix B-3. Control Strategies for ICI Boilers

Technology	Processes Covered	Efficiency of Control (% at the unit)	Notes	Reference
Retrofit Technologies for individual emission units				
LNB (Low NOX Burner)	Coal Sub-bituminous fueled boiler	51% NOX reduction		20
LNB + OFA (Over-fire air)	Coal Sub-bituminous fueled boiler	65% NOX reduction		20
	Coal Bituminous fueled boiler	51% NOX reduction		20
	Gas fueled boiler	60% NOX reduction		20
	Oil fueled boiler	30% NOX reduction		20
LNB + OFA + FGR (Flue Gas Recirculation)	Gas fueled boiler	80% NOX reduction		20, 26
LNB + OFA + FGR (0.5 lbs/mmBtu inlet NOx)	Oil fueled boiler	50% NOX reduction		20, 26
SCR	Coal fueled boiler	80% NOX reduction		20, 26
	Gas fueled boiler	80% NOX reduction		20, 26
	Oil fueled boiler	80% NOX reduction		20, 26
SNCR	Coal fueled boiler	40% NOX reduction		20, 26
	Oil fueled boiler	40% NOX reduction		20, 26
	Wood/Non-fossil solid fuel	not available		26
	Gas fueled boiler	40% NOX reduction		20
In-duct Dry Sorbent Injection (IDSI)	Coal High Sulfur fueled boiler	40% SO2 reduction		20
	Coal Low Sulfur fueled boiler	40% SO2 reduction		20
SDA	Coal fueled boiler	90% SO2 reduction		20
Wet FGD	Coal High Sulfur fueled boiler	90% SO2 reduction		20
	Coal Low Sulfur fueled boiler	90% SO2 reduction		20
	Oil fueled boiler	90% SO2 reduction		20
Water Injection	Gas fueled boiler	75% NOX reduction		26

[continued]

Appendix B-4. Control Strategies for Reciprocating Engines

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Low-Emission Combustion	Internal Combustion	80-90% reduction		27
Prestratified Charge	Internal Combustion	75-90% reduction		27
High Energy/Plasma Ignition Systems	Internal Combustion	80% reduction	cc	27
SCONOx Technology	Internal Combustion	95% reduction	dd	27
NOxTech System	Internal Combustion	90-95% reduction		27
High-pressure Fuel Injection	Internal Combustion	80% reduction		27
Air Fuel w/Ignition Retard	Internal Combustion - Gas	53 tons/30% reduction	hh	28, 29
Air Fuel w/Ignition Retard	IC Engines - Gas	53 tons/30% reduction	hh	28, 29
Air Fuel Ratio Adjustment	Internal Combustion - Gas	36 tons/20% reduction	hh	28, 29
Air Fuel Ratio Adjustment	IC Engines - Gas	38 tons/20% reduction	hh	28, 29
Ignition Retard	IC Engine - Oil	6 tons/25% reduction	hh	28, 29
Ignition Retard	IC Engines - Gas, Diesel, LPG	9 tons/25% reduction	hh	28, 29
L-E (Low Speed)	IC Engine - Gas	148 tons/87% reduction	hh	28, 29
L-E (Medium Speed)	IC Engine - Gas	98 tons/87% reduction	hh	28, 29
NSCR	IC Engine - Oil	19 tons/90% reduction	ee, hh	27, 28, 29
NSCR	IC Engine - Gas, Diesel, LPG	26 tons/90% reduction	ff, hh	27, 28, 29
SCR	IC Engine - Gas	150 tons/90% reduction	gg, hh	27, 28, 29
SCR	IC Engine - Gas, Diesel, LPG	23 tons/80% reduction	hh	27, 28, 29
SCR	IC Engine - Oil	17 tons/80% reduction	hh	27, 28, 29

Appendix B-5. Control Strategies for Turbines

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
External Flue Gas Recirculation	Turbine	N/A	ii	30
Overfire Air	Turbine	N/A		30
Low NOx Burners	Turbine	25-50% reduction		30
Selective Catalytic Reduction (High Dust)	Turbine	70-90% control efficiency	ii	30
Selective Catalytic Reduction (Low Dust)	Turbine	80-90% control efficiency		30
Selective Non-Catalytic Reduction	Turbine	25-50% control efficiency		30
Low Temperature Oxidation (Tri-NOx)	Turbine	99% control efficiency		30
Low Temperature Oxidation (LoTox)	Turbine	80-95% control efficiency		30
Non Selective Catalytic Reduction	Turbine	N/A	ii	30
Novel Multi-Pollutant Controls (Electro-Catalytic Oxidation)	Turbine	N/A		30
Novel Multi-Pollutant Controls (Pahlman Process)	Turbine	N/A	ii	30
SCONOx Technology	Gas Turbines	95% reduction		27
Dry Low NOx Combuster	Combustion Turbines - Natural Gas	102 tons/50% reduction	hh	28, 29
Dry Low NOx Combuster	Combustion Turbines - Natural Gas	102 tons/84% reduction	hh	28, 29
SCR w/Low NOx Burner	Combustion Turbines - Natural Gas	143 tons/94% reduction	hh	28, 29
SCR w/Steam Injection	Combustion Turbines - Natural Gas	145 tons/95% reduction	hh	28, 29
SCR w/Water Injection	Combustion Turbines - Natural Gas	145 tons/95% reduction	hh	28, 29
SCR w/Water Injection	Combustion Turbines - Oil	31 tons/90% reduction	hh	28, 29
SCR w/Water Injection	Combustion Turbines - Jet Fuel	13 tons/90% reduction	hh	28, 29
Steam Injection	Combustion Turbines - Natural Gas	119 tons/80% reduction	hh	28, 29
Water Injection	Combustion Turbines - Natural Gas	112 tons/76% reduction	hh	28, 29
Water Injection	Combustion Turbines - Oil	23 tons/68% reduction	hh	28, 29
Water Injection	Combustion Turbines - Jet Fuel	10 tons/68% reduction	hh	28, 29
Dry Low NOx Combuster	Combustion Turbines - Natural Gas	102 tons/50% reduction	hh	28, 29
Dry Low NOx Combuster	Combustion Turbines - Natural Gas	102 tons/84% reduction	hh	28, 29

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Floor housing system with stockpiling of manure	Storage and handling of poultry manure (solid)	N/A	jj	31
Cage housing system with conveyor belts	Storage and handling of poultry manure (solid)	N/A	jj	31
Cage housing system with deep pits	Storage and handling of poultry manure (solid)	N/A	jj	31
Lagoons/concrete tanks for storage of poultry manure	Storage of poultry manure (storage)	N/A	jj	31
Spread manure and incorporate within 3 days	Application of poultry manure (solid)	36 - 80% reduction	jj, kk	32
Spread manure and incorporate within 3 days	Application of dairy manure (solid and liquid)	70% reduction	jj, kk	32
Spread manure and incorporate within 3 days	Application of beef manure (solid and liquid)	36-70% reduction	jj, kk	32
Spread manure and incorporate within 3 days	Application of swine manure (solid and liquid)	36-70% reduction	jj, kk	32
Inject manure using tank wagon and incorporate with knives or disks	Application of dairy and beef manure (liquid)	N/A		33
Above-ground manure storage tanks	Storage of dairy and beef manure (solid and liquid)	N/A	ll	33
Walled enclosures to store manure	Storage of dairy and beef manure (solid and liquid)	N/A	mm	33
Outwinter cattle by rotating through pastures to "store" manure in frozen form until it can be used in the spring	Housing cattle (winter)	N/A		34
Outwinter cattle by keeping them outside in one paddock (sacrifice paddock) to store manure in one location	Housing cattle (winter)	N/A		34
Compost manure before applying	Treatment of livestock manure (solid and liquid)	N/A		35
Daily scraping and hauling of manure for collection and storage	Storage and handling of swine manure (solid)	42-63% reduction	jj, nn	36
Leaving manure to mix with bedding to form manure pack for collection and storage	Storage and handling of swine manure (solid)	33-50% reduction	jj, nn	36
Storing manure in lined pit	Storage and handling of swine manure (liquid)		jj, oo	36
Storing manure in above-ground storage facility	Storage and handling of swine manure (liquid)	25-50% reduction	jj, oo	36
Broadcasting manure w/incorporation into soil within 12 hours	Application of swine manure (solid)	80% reduction	jj, h1	36

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Broadcasting manure w/incorporation into soil within 4 days	Application of swine manure (solid)	40% reduction	jj, h1	36
Injection of manure with sweeps	Application of swine manure (liquid)	87% reduction	jj, h1	36
Injection of manure with knives	Application of swine manure (liquid)	62% reduction	jj, h1	36
Collection ponds to store manure	Storage and handling of swine manure (liquid)	N/A		37
Deep pits to store manure and minimize gas concentrations	Storage and handling of swine manure (solid)	N/A		37
Stockpile manure on concrete or clay pad	Storage and handling of swine manure (solid)	N/A		37
System than separates liquid and solid manure	Storage and handling of swine manure (solid)	N/A		37
Composting manure	Treatment of swine manure (liquid and solid)	N/A		37
Anaerobic lagoons and digesters to store and "treat" manure	Treatment of swine manure (liquid and solid)	N/A		37
Oxidation ditches and aerated lagoons to store and "treat" manure	Treatment of swine manure (liquid and solid)	N/A		37
Daily scraping and hauling of manure for collection and storage	Storage and handling of poultry manure (solid)	42-63% reduction	jj, nn	38
Leaving manure to mix with bedding to form manure pack for collection and storage	Storage and handling of poultry manure (solid)	33-50% reduction	jj, nn	38
Broadcasting manure w/incorporation into soil within 12 hours	Application of poultry manure (solid)	83% reduction	jj, h1	38
Broadcasting manure w/incorporation into soil within 4 days	Application of poultry manure (solid)	33% reduction	jj, h1	38

[continued]

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Daily scraping and hauling of manure for collection and storage	Storage and handling of dairy manure (solid)	42-62% reduction	jj, nn	39
Leaving manure to mix with bedding to form manure pack for collection and storage	Storage and handling of dairy manure (solid)	30-50% reduction	jj, nn	39
Storing manure in lined pit	Storage and handling of dairy manure (liquid)	25% reduction	jj, oo	39
Storing manure in above-ground storage facility	Storage and handling of dairy manure (liquid)	25-50% reduction	jj, oo	39
Broadcasting manure w/incorporation into soil within 12 hours	Application of dairy manure (solid)	75% reduction	jj, h1	39
Broadcasting manure w/incorporation into soil within 4 days	Application of dairy manure (solid)	50% reduction	jj, h1	39
Injection of manure with sweeps	Application of dairy manure (liquid)	86% reduction	jj, h1	39
Injection of manure with knives	Application of dairy manure (liquid)	71% reduction	jj, h1	39
Daily scraping and hauling of manure for collection and storage	Storage and handling of beef manure (solid)	42-63% reduction	jj, nn	40
Leaving manure to mix with bedding to form manure pack for collection and storage	Storage and handling of beef manure (solid)	33-50% reduction	jj, nn	40
Storing manure in lined pit	Storage and handling of beef manure (liquid)	25% reduction	jj, oo	40
Storing manure in above-ground storage facility	Storage and handling of beef manure (liquid)	25-50% reduction	jj, oo	40
Broadcasting manure w/incorporation into soil within 12 hours	Application of beef manure (solid)	87% reduction	jj, h1	40
Broadcasting manure w/incorporation into soil within 4 days	Application of beef manure (solid)	50% reduction	jj, h1	40
Injection of manure with sweeps	Application of beef manure (liquid)	56% reduction	jj, h1	40
Injection of manure with knives	Application of beef manure (liquid)	71% reduction	jj, h1	40
Best Management Practices		N/A		41
Manure Storage Covers	Storage of livestock manure (solid and liquid)	N/A		41
Manure Digesters (Biogas)	Handling of livestock manure (solid and liquid)	N/A		41
Animal Lot Increased Cleaning		N/A		41
Injection of manure into fields	Application of livestock manure (liquid)	N/A		41

[continued]

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Nutrient Management Plans	Housing, storage, handling, and application of livestock manure (solid and liquid)	N/A		41
Earthen storage	Storage of manure (solid and liquid)	N/A	qq	42
Clay-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Geomembrane-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Geosynthetic clay-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Concrete-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Manure storage structure	Storage of manure (solid and liquid)	N/A	qq	42
Clay-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Geomembrane-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Geosynthetic clay-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Concrete-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Nitrification inhibitor	Handling of livestock manure (liquid)	N/A	ss	43
Minimize application on frozen or snow-covered ground	Application of livestock manure (solid and liquid)	N/A		44
Apply manure on crops that can use all of its nutrients	Application of livestock manure (solid and liquid)	N/A		44
Incorporate or inject manure within 72 hours using urease inhibitor	Application of livestock manure (solid and liquid)	N/A		44
Cover manure storage structures or use organic matter in bedding to form a crust cover	Storage of livestock manure (solid and liquid)	N/A		44
Divert urine away from feces	Handling of livestock manure (solid and liquid)	N/A		44
Incorporate manure	Application of dairy manure	10% reduction	jj, kk	44
Incorporate manure	Application of beef manure	10% reduction		44
Incorporate manure	Application of swine manure (solid)	15% reduction		44
Incorporate manure	Application of swine manure (liquid)	15% reduction	tt	44

[continued]

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Incorporate manure	Application of poultry manure	10% reduction	uu	44
Incorporate manure	Application of sheep manure (solid)	10% reduction		44
Incorporate manure	Application of horse manure (solid)	10% reduction		44
Solid and liquid separation system	Handling of liquid and solid manure	N/A	vv	45
Treat waste by mechanical, chemical, or biological means	Treatment of livestock manure (solid and liquid)	N/A		46, 47
Hopper to transfer manure	Handling of liquid and solid manure	N/A		48
Reception structure or tank to transfer manure	Handling of liquid and solid manure	N/A	ww	48
Piston pumps to transfer manure to storage or treatment structure	Handling of liquid and solid manure	N/A		48
Channels to transfer manure (gravity transfer)	Handling of liquid and solid manure	N/A	xx	48
Transfer pipes to transfer manure to storage or treatment structure	Handling of liquid and solid manure	N/A	xx	48
Pipelines (gravity transfer)	Handling of liquid and solid manure	N/A		48

[continued]

Appendix B-7. References for Control Strategies

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[continued]

Appendix B-8. Notes on Control Strategies

a. Implementation: use existing authorities like anti-tampering compliance authority, pursuing a mandatory program based on current draft OTC model rule, or working with engine manufacturers on a voluntary program.

b. Southeastern Wisconsin already requires tailpipe and OBDII inspections on passenger vehicles. This recommendation would expand the program to all of WI, re-start and expand the program in MN, and start a program in MI. Requires promulgation of State laws. (Similar measures were also mentioned in ENVIRON's phase I mobile source strategy

c. MOBILE5 estimates a 9% total emission inventory reduction with a fully implemented enhanced IM program. However, a NAS report in 2001 found that this may be an overestimation. The ENVIRON Phase I mobile source control measures report estimates an 8% NOX reduction in 2007 if all states in the LADCO region fully implemented an IM and OBD

d. Co-benefits of this strategy are significant. PM, HC, and CO are reduced by 48, 48, and 68% respectively. Cetane

e. Co-benefits of this strategy are significant. PM, HC, and CO are reduced by 10, 21, and 11% respectively. 98% of vehicles in this study are pre-1998. Cetane additives may decrease NOX emissions.

f. Opacity reduced 2-6% when switching from regular diesel to B20

g. Opacity reduced 5-11% when switching from regular diesel to B30

h. This test did not demonstrate PM or HC reductions using B20 or CARB diesel.

i. Emission benefits are not readily available for most nonroad applications. However, biodiesel is being used for

j. 1% NOX reduction for line-haul locomotives, 2% for switching.

k. Based on Port of Los Angeles Emissions Inventory. Percentage may differ for LADCO region.

l. Co-benefits include reductions in PM, CO, and greenhouse gases. Low blends of ethanol demonstrate a slight increase in VOC cold-start emissions when compared to regular gasoline.

m. ENVIRON report assumes 15% participation in 2009 and 30% participation of HDDV anti-idling measures by 2012. The report also assumes 25% and 50% of switching and linehaul locomotives respectively.

n. Calculation of percentage NOX control efficiency would require knowledge of the percentage of time a truck would participate in anti-idling programs. It is assumed that 100% of NOX would be reduced during the anti-idling time.

o. Control efficiency was cited from the ENVIRON Phase II report.

p. Control efficiencies were calculated based on the g/bhp-hr engine standard of the upgraded engine vs. the old engine.

q. Also demonstrates 10-30% PM reduction

r. ENVIRON Phase II report analyzes emission reductions and cost-effectiveness of LNC combined with DPF, resulting in PM reduction co-benefits and combined costs results.

s. ENVIRON Phase II report analyzes emission reductions and cost-effectiveness of EGR combined with DPF, resulting in PM, VOC, and CO reduction co-benefits and combined costs results.

t. ENVIRON Phase II report analyzes emission reductions and cost-effectiveness of SCR combined with DOC, resulting in PM, VOC, and CO reduction co-benefits and combined costs results.

u. ENVIRON Phase II report analyzes emission reductions and cost-effectiveness of SCR combined with DPF, resulting in PM, VOC, and CO reduction co-benefits and combined costs results.

v. Candidate measure ID EGU1

w. Candidate measure ID EGU2

x. Candidate measure ID ICI1. *Timing of Implementation* : Assumes full reductions achieved in 2009. *Implementation*

y. Candidate measure ID ICI2. *Timing of Implementation* : Assumes full reductions achieved in 2013 *Implementation Area* :

z. Candidate measure ID ICI3. *Timing of Implementation* : Assumes full reductions achieved in 2009 *Implementation Area* :

aa. Applies to CO, HC (and toxics), PM, and somewhat for NOx, probably for nontailpipe HCs. Fresno Study referenced in Doug Lawson's presentation cited a 53% reduction in NOX, 65% in HC, and 94% in CO.

bb. Baseline and on-the-way measures are listed here as additional information that was provided by the LADCO white papers. We will include discussion on these existing or upcoming measures for all source categories in our final report.

Appendix B-8. Notes on Control Strategies

cc. used only on lean burn, natural gas spark ignited engines
dd. natural gas- and diesel-fired
ee. source 27 states 95% efficiency for rich-burn spark ignited engines
ff. source 27 states 95% efficiency for rich-burn spark ignited engines
gg. source 27 states 90% efficiency for internal combustion sources
hh. AirControlNET provided information on control technologies from multiple pollution sources; the reduction in tons listed under "Efficiency Estimate (%)" is an average of all the sources for a particular technology
ii. high cost
jj. Efficiency calculations are based on estimates of atmospheric losses, assuming a consistent distribution of losses among ammonia and other gases (N2O and N2)
kk. Baseline is spreading manure without incorporation
ll. Costly, even with cost-sharing, average price is $1000/cow
mm. Moderate to high cost
nn. Baseline is open ground storage (leaving manure on ground with no method of collection or storage)
oo. Baseline is earthen ground storage (leaving manure on ground with no method of collection or storage)
pp. Baseline is broadcasting manure with no waiting time before incorporation
qq. no particular strategy is described as "best practice" but State offers technical specifications for structures to meet standard, e.g., storage volume, depth, how much stress can be placed on the structure depending on the material
ss. the inhibitor works on ammonium forms of nitrogen; it is recommended to use this technique in the late summer or fall; reference also recommends timings of manure application (specific soil temperatures)
tt. reference broke out nutrient availability among indoor pit, outdoor pit, and farrow-nursery indoor pit storage options; all
uu. reference broke out nutrient availability among duck, chicken, turkey, and poultry manure; all had same nutrient
vv. reference provides efficiency in capturing solids from waste stream
ww. reference provides technical specifications for dimensions and distances from water sources
xx. reference provides material components and technical specifications for transfer mechanism

[continued]

Appendix C
EGU Control Analysis Parameters and Individual EGU and ICI Boiler Facility Analyses

Contents

Tables

C.1 Cost Equations and Control Efficiencies for EGU

Costs for regional EGU control strategies were analyzed using cost equations developed for the Integrated Planning Model (IPM).[1] The IPM model is commonly used to estimate the costs of large-scale pollution control programs. The cost equation parameters are shown in Table C-1. Control efficiencies used in the EGU regional strategy analyses are shown in Table C-2.

C.2 EGU and ICI Boiler Individual Facility Analyses

Eleven electric generating facilities were selected for more in-depth analyses. The analyses of these facilities were designed to ensure that opportunities for cost-effective visibility improvements were not overlooked. None of these facilities are required to completed BART analyses nor are they expected to reduce emissions pursuant to CAIR. Each of these facilities includes multiple boilers, totaling 35 individual boilers that were analyzed. For these plant-specific analyses we estimated costs using the IPM cost equations,[3] and also drew on a number of additional data sources, including a Menu of Options for controlling $PM_{2.5}$ and its precursors by the National Association of Clean Air Agencies (NACAA, formerly STAPPA and ALAPCO)[2] and the Coal Utility Environmental Cost (CUECost) worksheet.[3] For ICIs smaller than 100 MW, an ICI boiler cost estimation methodology developed by EPA was used.[4,5]

Tables C-1 through C-11 present detailed estimates of capital and annualized costs for each individual unit, emissions reductions, and cost effectiveness for each control technology. The control technologies were selected to achieve the either the EGU1 cap or both the EGU1 and EGU2 caps. Table C-12 is the analysis for an ICI boiler at Boise Cascade Corporation.[a] In this case, the control technologies meet both the ICI1 rule and the ICI Workgroup recommendation.

It must be noted that the reported results are estimates. In fact, control cost estimates can vary by at a factor of 2 or more. There are a number of reasons for this range of cost estimates. First, all of the costing approaches rely on default assumptions for flue gas conditions, and for retrofit costs and other contingency costs. These assumptions may differ from model to model. In addition, the cost equations have been developed for different base years, and use different inflation factors to project costs to subsequent years. The CueCost and IPM models also use

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[a]The ICI Workgroup recommendation and the *Candidate Measure ID ICI1* control strategies discussed in section 5.2 are used in this facility analysis. The Workgroup recommendation results in a regional cap for SO_2 emissions of 1.2 lb/mmBtu (a 77% rollback of emissions for either the 3-state or 9-state region). When conducting the facility analysis of an ICI boiler (Boise Cascade Corporation/International Falls in Minnesota) we found only one unit at the facility emitted SO_2. The remaining units all burned natural gas and so had negligible SO_2 emissions. According to Boise's 2005 permit, the SO_2 emissions from Unit 2 amount to .1 lb/mmBtu, well below the regional emissions caps. Therefore, this facility would not be controlled under this rule for SO_2, and further cost analysis for ICI1 was not necessary. Analyses were conducted for ICI1 NO_X, and the Workgroup recommendation for both NO_X and SO_2.

different scaling factors to calculate costs for various boiler sizes. The NACAA report only provides cost effectiveness values for broad boiler size ranges.

C.3 Example CUECOST Individual Facility Input Spreadsheet

CUECost is a set of interrelated Excel spreadsheets that focus on costs for coal-fired power plants. In the CUECost spreadsheets, the user has the ability to change all the parameters to suit the facility under analysis. A sensitivity analysis of CUECost conducted by EPA has shown that the following variables have significant impacts on the cost results (greater than 5%):[6]

- Unit capacity
- Heat rate
- Coal sulfur content
- Coal heating value
- Capacity factor
- Disposal mode

Unit capacities and heat rates for individual EGUs were obtained from the NEEDS database, and capacity factors for 2018 were calculated based on the IPM unit-specific fuel consumption estimates. Fuel sulfur contents were obtained from operating permits, where possible, or calculated from SO_2 emission rates reported in the NEI database. We assumed that the disposal mode for sludge and ash will be landfilling. It must be noted that the results are ball-park figures; default values were used when plant-specific information required by CUECost was not available in the operating permits.

Tables C-17 and C-18 show an example of an individual facility analysis with the CUECost program. Table C-20 shows the inputs for the program, and Table C-21 presents the results. This example is from the JH Campbell facility in Michigan, which has three units (Boilers 1, 2 and 3). Plant-specific information was used in the highlighted rows (the same type of information was available for all other facilities as well). CUECost allows the user to specify the type of coal being used at the facility, either choosing from its coal library or, if the coal is not found in the library, input the coal characteristics for more accurate results. We often exercised the latter option in our analyses. In this example Boiler 3 uses a different coal than Boilers 1 and 2. In cases like this, two separate analyses were conducted (i.e., two separate spreadsheets were used): one for the boilers using coal type A and a second for boilers using coal type B.

References for Appendix C

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Table C-1. IPM Cost Equation Parameters Used for EGU Control Strategy Analyses

Control technology	Fuel and boiler type	Capital cost factors*			Fixed operating and maintenance scaling factors*			Variable operating and maintenance cost factors*		
		Base value ($/kW)	Scale factor	Expon-ent	Base value ($/kW-yr)	Scale factor	Expon-ent	Base value (cents/kWh)	Scale factor	Expon-ent
SO2 Controls										
Limestone forced oxidation scrubber	<100 MW	511.1	100	0.62	20.75	100	0.47	0.153	na	na
	100-300 MW	251.2	300	0.62	12.01	300	0.39	0.153	na	na
	300-500 MW	190.0	500	0.55	9.83	500	0.35	0.153	na	na
	500-700 MW	155.1	700	0.60	8.74	700	0.37	0.153	na	na
	>700 MW	131.0	1,000	0.47	7.64	1,000	0.37	0.153	na	na
Lime spray dryer scrubber	<100 MW	312.3	100	0.50	14.20	100	0.47	0.153	na	na
	100-300 MW	169.3	300	0.33	8.74	300	0.56	0.153	na	na
	300-500 MW	143.1	500	0.31	6.55	500	0.54	0.153	na	na
	500-700 MW	128.9	700	0.15	5.46	700	0.63	0.153	na	na
	>700 MW	122.3	1,000	0.15	4.37	1,000	0.63	0.153	na	na
NOX Controls										
SCR	Coal	133.8	243	0.27	0.89	243	0.27	0.080	243	0.11
	Oil / gas	38.6	200	0.35	1.19	200	0.35	0.013	na	na
SNCR	Coal, pulverized, term 1**	22.9	200	0.58	0.34	200	0.58	0.118	na	na
	Coal, pulverized, term 2**	26.1	100	0.68	0.40	100	0.68	0.118	na	na
	Coal, cyclone	13.2	300	0.58	0.19	300	0.58	0.223	na	na
	Coal, fluidized bed	22.9	200	0.58	0.35	200	0.58	0.102	na	na
	Oil / gas	13.0	200	0.58	0.20	200	0.58	0.060	na	na
LNB without OFA	Coal, wall-fired	23.1	300	0.36	0.35	300	0.36	0.007	na	na
LNB with OFA	Coal, wall-fired	31.3	300	0.36	0.48	300	0.36	0.010	na	na
LNB with close-coupled OFA	Coal, tangential	12.2	300	0.36	0.02	300	0.36	0.000	na	na
LNB with separated OFA	Coal, tangential	17.0	300	0.36	0.25	300	0.36	0.003	na	na
LNB with close-coupled and separated OFA	Coal, tangential	19.4	300	0.36	0.30	300	0.36	0.003	na	na
Limestone forced oxidation scrubber	<100 MW	511.1	100	0.62	20.75	100	0.47	0.153	na	na
	100-300 MW	251.2	300	0.62	12.01	300	0.39	0.153	na	na
	300-500 MW	190.0	500	0.55	9.83	500	0.35	0.153	na	na
	500-700 MW	155.1	700	0.60	8.74	700	0.37	0.153	na	na
	>700 MW	131.0	1,000	0.47	7.64	1,000	0.37	0.153	na	na
Lime spray dryer scrubber	<100 MW	312.3	100	0.50	14.20	100	0.47	0.153	na	na
	100-300 MW	169.3	300	0.33	8.74	300	0.56	0.153	na	na
	300-500 MW	143.1	500	0.31	6.55	500	0.54	0.153	na	na
	500-700 MW	128.9	700	0.15	5.46	700	0.63	0.153	na	na
	>700 MW	122.3	1,000	0.15	4.37	1,000	0.63	0.153	na	na

* Cost equations take the following form: Cost = (Base value) x (Scale Factor/MW)^(exponent)

where "Base value," "Scale factor," and "exponent" are terms defined in the table, and MW is the capacity of the boiler

**For SNCR applied to pulverized coal, terms 1 and 2 are added together.

Source: Reference 1

Table C-2. Emission Control Efficiencies Used for EGU Control Strategy Analyses

Control technology	Fuel and boiler type	Estiamated control efficiency (%)
SO_2 control measures		
Limestone forced oxidation scrubber	Coal /oil	95
Lime spray dryer scrubber	Coal /oil	90
NO_X control measures		
SCR	Coal	90
	Oil / gas	80
SNCR	Coal, pulverized or cyclone	35
	Coal, fluidized bed	50
	Oil / gas	50
LNB without OFA	Coal, wall-fired	35
LNB with OFA	Coal, wall-fired	40
LNB with close-coupled OFA	Coal, tangential	40
LNB with separated OFA	Coal, tangential	45
LNB with close-coupled and separated OFA	Coal, tangential	50

Table C-3. Estimated Cost and Cost Effectiveness for EGU1 and EGU2 Control Strategies for the Detroit Edison/St. Clair-Belle River Facility (Michigan)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	St. Clair/ Belle River	1	Coal	153	5,491	LSD	90	CUECost	54,602	6,604	14,783	4,942	2,991	10,628	18,012	4,942	5,216	150-3452
								IPM	44,092	4,023	10,628	4,942	2,151					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	71,543	7,295	18,012	5,216	3,453					
								IPM	69,090	4,938	15,288	5,216	2,931					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	162	6,162	LSD	90	CUECost	59,169	7,156	16,020	5,546	2,888	11,009	19,257	4,942	5,216	150-3289
								IPM	45,379	4,211	11,009	5,546	1,985					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	76,687	7,769	19,257	5,854	3,289					
								IPM	70,608	5,155	15,732	5,854	2,687					
								STAPPA	-	-	-	-	200-5000					
		3	Coal	171	6,132	LSD	90	CUECost	58,567	7,149	15,923	5,519	2,885	11,425	19,263	4,942	5,825	150-3306
								IPM	46,631	4,440	11,425	5,519	2,070					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	76,094	7,864	19,263	5,825	3,307					
								IPM	72,074	5,412	16,209	5,825	2,783					
								STAPPA	-	-	-	-	200-5000					
		4	Coal	158	5,734	LSD	90	CUECost	56,209	6,840	15,260	5,160	2,957	10,774	18,434	4,942	5,447	150-3384
								IPM	44,811	4,061	10,774	5,160	2,088					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	73,110	7,482	18,434	5,447	3,384					
								IPM	69,940	4,992	15,469	5,447	2,840					
								STAPPA	-	-	-	-	200-5000					
		6	Coal	321	11,765	LSD	90	CUECost	75,056	10,823	22,066	10,588	2,084	16,444	25,653	4,942	11,176	150-2295
								IPM	61,545	7,224	16,444	10,588	1,553					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	92,898	11,737	25,653	11,176	2,295					
								IPM	89,995	8,446	21,928	11,176	1,962					
								STAPPA	-	-	-	-	200-5000					
		7	Coal	450	11,765	LSD	90	CUECost	90,888	15,164	28,779	10,588	2,718	21,036	32,737	4,942	11,176	150-2929
								IPM	77,195	9,472	21,036	10,588	1,987					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	111,146	16,088	32,737	11,176	2,929					
								IPM	104,903	11,187	26,902	11,176	2,407					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**1,415**	**47,048**									**77,147**	**133,356**	**42,344**	**44,696**	**1822-2984**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	St. Clair/ Belle River	1	Coal	153	1,071	SCR	90	CUECost	15,493	1,520	3,602	963	3,739	599	6,764	375	963	200-1148
								IPM	24,436	1,143	4,428	963	4,596					
								STAPPA	-	-	-	-	1000-2000					

Table C-3. Estimated Cost and Cost Effectiveness for EGU1 and EGU2 Control Strategies for the Detroit Edison/St. Clair-Belle River Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
						SNCR	35	CUECost	2,219	301	599	375	1,600					
								IPM	3,727	1,420	1,921	375	5,126					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	5,375	120	843	375	2,250					
								IPM	4,741	155	792	375	2,114					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	5,006	6,091	6,764	589	11,488					
								IPM	-	-	-	589	-					
								STAPPA	-	-	-	-	500-2000					
		2	Coal	162	1,693	SCR	90	CUECost	17,433	1,736	4,079	1,524	2,677	744	7,595	593	1,524	200-8156
								IPM	25,477	1,207	4,631	1,524	3,039					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,479	411	744	593	1,255					
								IPM	3,809	1,508	2,020	593	3,409					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	5,579	125	875	593	1,476					
								IPM	-	-	-	593	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	5,339	6,878	7,595	931	8,156					
								IPM	-	-	-	931	-					
								STAPPA	-	-	-	-	500-2000					
		3	Coal	171	1,195	SCR	90	CUECost	16,866	1,651	3,918	1,076	3,641	638	7,505	418	1,076	200-1141
								IPM	26,503	1,291	4,853	1,076	4,510					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,376	319	638	418	1,525					
								IPM	3,888	1,627	2,149	418	5,137					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	5,778	129	906	418	2,166					
								IPM	-	-	-	418	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	5,485	6,767	7,505	657	11,414					
								IPM	-	-	-	657	-					
								STAPPA	-	-	-	-	500-2000					
		4	Coal	158	1,118	SCR	90	CUECost	16,244	1,616	3,799	1,006	3,776	609	7,079	391	1,006	200-1151
								IPM	25,017	1,145	4,507	1,006	4,480					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,276	303	609	391	1,556					
								IPM	3,773	1,422	1,929	391	4,931					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	5,489	123	861	391	2,200					
								IPM	4,840	157	807	391	2,063					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	5,083	6,396	7,079	615	11,514					
								IPM	-	-	-	615	-					
								STAPPA	-	-	-	-	500-2000					

Table C-3. Estimated Cost and Cost Effectiveness for EGU1 and EGU2 Control Strategies for the Detroit Edison/St. Clair-Belle River Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		6	Coal	321	1,766	SCR	90	CUECost	25,234	2,886	6,278	1,589	3,950	846	13,028	618	1,589	200-1341
								IPM	41,972	2,180	7,821	1,589	4,921					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,070	433	846	618	1,369					
								IPM	4,939	2,942	3,606	618	5,834					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	8,701	195	1,364	618	2,207					
								IPM	-	-	-	618	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	7,844	11,974	13,028	971	13,414					
								IPM	-	-	-	971	-					
								STAPPA	-	-	-	-	500-2000					
		7	Coal	450	1,766	SCR	90	CUECost	33,526	4,143	8,648	1,589	5,442	1,214	10,190	618	1,589	200-7980
								IPM	53,710	2,972	10,190	1,589	6,412					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,891	691	1,214	618	1,964					
								IPM	5,619	4,177	4,932	618	7,980					
								STAPPA	-	-	-	-	800-1500					
	Plant Total			**1,415**	**8,609**									**4,649**	**51,639**	**3,013**	**7,748**	**1543-6665**

Table C-4. Consumers Energy Company/JH Campbell Facility (Michigan)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	JH Campbell	1	Coal	260	10,767	LSD	90	CUECost	78,193	11,709	23,423	9,690	2,417	14,483	24,314	9,690	10,229	150-2417
								IPM	57,580	5,858	14,483	9,690	1,495					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	93,492	10,309	24,314	10,229	2,377					
								IPM	84,520	7,077	19,738	10,229	1,930					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	355	12,986	LSD	90	CUECost	83,538	13,935	26,449	11,688	2,263	17,567	27,430	11,688	12,337	150-2263
								IPM	65,844	7,704	17,567	11,688	1,503					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	99,523	12,521	27,430	12,337	2,223					
								IPM	94,201	9,060	23,171	12,337	1,878					
								STAPPA	-	-	-	-	200-5000					
		3	Coal	820	30,020	LSD	90	CUECost	112,653	24,860	41,735	27,018	1,545	32,371	47,039	27,018	28,519	150-1649
								IPM	119,585	14,457	32,371	27,018	1,198					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	156,806	23,550	47,039	28,519	1,649					
								IPM	136,680	17,580	38,055	28,519	1,334					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**1435**	**53773**									**64,421**	**98,783**	**48,396**	**51,085**	**1331-1934**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	JH Campbell	1	Coal	260	3,153	SCR	78	CUECost	29,285	3,146	7,082	2,459	2,880	1,116	12,797	1,104	2,459	200-7379
								IPM	35,987	1,719	6,556	2,459	2,666					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,316	671	1,116	1,104	1,012					
								IPM	4,559	2,250	2,862	1,104	2,594					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	7,589	170	1,190	1,104	1,078					
								IPM	-	-	-	1,104	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	6,885	11,872	12,797	1,734	7,379					
								IPM	-	-	-	1,734	-					
								STAPPA	-	-	-	-	500-2000					

Table C-4. Consumers Energy Company/JH Campbell Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		2	Coal	355	7,359	SCR	88	CUECost	33,388	4,005	8,492	6,476	1,311	1,457	15,574	2,576	6,476	200-3848
								IPM	45,173	2,336	8,407	6,476	1,298					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,946	1,424	1,954	2,576	759					
								IPM	5,133	3,182	3,872	2,576	1,503					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	9,292	208	1,457	2,576	566					
								IPM	-	-	-	2,576	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	8,375	14,448	15,574	4,047	3,848					
								IPM	-	-	-	4,047	-					
								STAPPA	-	-	-	-	500-2000					
		3	Coal	820	11,799	SCR	70	CUECost	64,401	8,825	17,481	8,259	2,117	2,511	17,481	4,130	8,259	200-2117
								IPM	90,557	4,830	17,000	8,259	2,058					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	6,647	2,231	3,124	4,130	757					
								IPM	7,069	6,937	7,887	4,130	1,910					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	16,012	359	2,511	4,130	608					
								IPM	-	-	-	4,130	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	17,069	6,921	9,215	6,489	1,420					
								IPM	-	-	-	6,489	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**1435**	**22311**									**5,084**	**45,851**	**7,809**	**17,194**	**651-2667**

Table C-5. Wisconsin Electric/Presque Isle Facility (Michigan)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	WI Electric/Presque Isle	5	Coal	88	3,431	LSD	90	CUECost	45,698	4,761	11,607	3,088	3,759	6,536	14,697	3,088	3,259	150-4509
								IPM	27,815	2,369	6,536	3,088	2,117					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	62,139	5,389	14,697	3,259	4,509					
								IPM	46,657	2,935	9,924	3,259	3,045					
								STAPPA	-	-	-	-	200-5000					
		6	Coal	88	3,416	LSD	90	CUECost	45,635	4,750	11,586	3,075	3,768	6,536	14,680	3,075	3,245	150-4523
								IPM	27,815	2,369	6,536	3,075	2,126					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	62,076	5,381	14,680	3,245	4,523					
								IPM	46,657	2,935	9,924	3,245	3,058					
								STAPPA	-	-	-	-	200-5000					
		7	Coal	88	2,046	LSD	90	CUECost	47,226	5,026	12,100	1,842	6,570	6,536	15,113	1,842	1,944	150-7773
								IPM	27,815	2,369	6,536	1,842	3,549					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	63,665	5,576	15,113	1,944	7,773					
								IPM	46,657	2,935	9,924	1,944	5,104					
								STAPPA	-	-	-	-	200-5000					
		8	Coal	88	1,965	LSD	90	CUECost	46,584	4,914	11,893	1,768	6,726	6,536	14,938	1,768	1,866	150-8004
								IPM	27,815	2,369	6,536	1,768	3,697					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	63,027	5,497	14,938	1,866	8,004					
								IPM	46,657	2,935	9,924	1,866	5,317					
								STAPPA	-	-	-	-	200-5000					
		9	Coal	88	1,967	LSD	90	CUECost	46,605	4,918	11,899	1,770	6,721	6,536	14,944	1,770	1,869	150-7997
								IPM	27,815	2,369	6,536	1,770	3,692					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	63,047	5,499	14,944	1,869	7,997					
								IPM	46,657	2,935	9,924	1,869	5,310					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**440**	**12,825**									**32,679**	**74,371**	**11,543**	**12,184**	**2831-6104**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	WI Electric/Presque Isle	5	Coal	88	1,012	SCR	90	CUECost	12,663	988	2,690	910	2,954	427	4,066	354	910	200-7308
								IPM	16,319	685	2,878	910	3,161					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,916	288	546	354	1,542					
								IPM	3,023	799	1,205	354	3,404					
								STAPPA	-	-	-	-	800-1500					

Table C-5. Wisconsin Electric/Presque Isle Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
						LNB	35	CUECost	2,720	61	427	354	1,205					
								IPM	-	-	-	354	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,534	4,066	556	7,308					
								IPM	-	-	-	556	-					
								STAPPA	-	-	-	-	500-2000					
		6	Coal	88	1,049	SCR	90	CUECost	12,630	984	2,681	944	2,839	427	4,051	367	944	200-7020
								IPM	16,319	685	2,878	944	3,047					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,913	288	545	367	1,483					
								IPM	3,023	799	1,205	367	3,282					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,720	61	427	367	1,161					
								IPM	-	-	-	367	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,519	4,051	577	7,020					
								IPM	-	-	-	577	-					
								STAPPA	-	-	-	-	500-2000					
		7	Coal	88	1,218	SCR	90	CUECost	13,467	1,082	2,892	1,096	2,640	427	4,430	426	1,096	200-6615
								IPM	16,319	685	2,878	1,096	2,626					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,982	308	574	426	1,348					
								IPM	3,023	799	1,205	426	2,828					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,720	61	427	426	1,001					
								IPM	-	-	-	426	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,897	4,430	670	6,615					
								IPM	-	-	-	670	-					
								STAPPA	-	-	-	-	500-2000					
		8	Coal	88	1,063	SCR	90	CUECost	13,130	1,042	2,807	957	2,934	427	4,276	372	957	200-7314
								IPM	16,319	108	2,302	957	2,406					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,954	300	562	372	1,512					
								IPM	3,023	799	1,205	372	3,240					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,720	61	427	372	1,146					
								IPM	-	-	-	372	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,744	4,276	585	7,314					
								IPM	-	-	-	585	-					
								STAPPA	-	-	-	-	500-2000					

Table C-5. Wisconsin Electric/Presque Isle Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		9	Coal	88	1,120	SCR	90	CUECost	13,141	1,044	2,690	1,008	2,668	427	4,066	392	1,008	200-6084
								IPM	16,319	685	2,878	1,008	2,854					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,955	300	546	392	1,392					
								IPM	3,023	799	1,205	392	3,074					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,720	61	427	392	1,088					
								IPM	-	-	-	392	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,749	4,066	616	6,084					
								IPM	-	-	-	616	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**440**	**5,462**									**2,133**	**20,890**	**1,912**	**4,916**	**1116-4250**

Table C-6. Minnesota Power/Clay Boswell Facility (Minnesota)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Clay Boswell	1	Coal	69	2,587	LSD	90	CUECost	45,601	5,271	12,102	2,328	5,198	5,660	14,108	2,328	2,458	150-5741
								IPM	24,610	1,974	5,660	2,328	2,431					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	59,232	5,235	14,108	2,458	5,741					
								IPM	42,536	2,469	8,841	2,458	3,598					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	69	2,572	LSD	90	CUECost	46,112	5,266	12,174	2,315	5,259	5,625	14,169	2,315	2,443	150-5799
								IPM	24,610	1,938	5,625	2,315	2,430					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	59,739	5,220	14,169	2,443	5,799					
								IPM	42,536	2,434	8,806	2,443	3,604					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**138**	**5159**									**11,285**	**28,276**	**4,643**	**4,901**	**2431-5770**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Clay Boswell	1	Coal	69	693	SCR	90	CUECost	10,693	761	2,198	624	3,524	472	3,157	243	624	500-8281
								IPM	13,664	550	2,387	624	3,825					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,754	237	472	243	1,947					
								IPM	2,758	627	997	243	4,111					
								STAPPA	-	-	-	-	800-1500					
						NGR	55	CUECost	3,635	2,669	3,157	381	8,281					
								IPM	-	-	-	381	-					
								STAPPA	-	-	-	-	500-2000					
		2	Coal	69	689	SCR	90	CUECost	10,937	781	2,251	620	3,628	474	3,142	241	620	500-8289
								IPM	13,664	531	2,367	620	3,817					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,773	236	474	241	1,965					
								IPM	2,758	602	973	241	4,032					
								STAPPA	-	-	-	-	800-1500					
						NGR	55	CUECost	3,635	2,654	3,142	379	8,289					
								IPM	-	-	-	379	-					
								STAPPA	-	-	-	-	500-2000					
		4	Coal	426	4,859	SCR	90	CUECost	36,447	3,805	8,703	4,373	1,990	1,408	23,558	1,701	4,373	500-8815
								IPM	51,611	3,525	10,461	4,373	2,392					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,919	882	1,408	1,701	828					
								IPM	5,503	5,033	5,773	1,701	3,394					
								STAPPA	-	-	-	-	800-1500					
						NGR	55	CUECost	9,854	22,234	23,558	2,673	8,815					
								IPM	-	-	-	2,673	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**564**	**6242**									**2,355**	**29,857**	**2,185**	**5,617**	**1078-5315**

Table C-7. Minnesota Power/Syl Laskin Facility (Minnesota)*

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Syl Laskin	1	Coal	55	951	LSD	90	CUECost	44,526	4,856	11,526	856	13,460	4,955	11,526	856	904	150-13460
								IPM	21,945	1,668	4,955	856	5,786					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	37,652	4,253	9,894	904	10,945					
								IPM	39,005	2,106	7,949	904	8,794					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	55	950	LSD	90	CUECost	58,190	4,856	13,573	855	15,873	4,698	13,573	855	903	150-15873
								IPM	21,945	1,662	4,949	855	5,788					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	58,192	4,852	13,569	903	15,033					
								IPM	39,005	2,100	7,943	903	8,800					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**110**	**1902**									**9,653**	**25,099**	**1,711**	**1,807**	**5640-13894**

* This facility is installing NOx controls so NOx control costs were not evaluated

Table C-8. Northshore Mining Company/Silver Bay Facility (Minnesota)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Northshore/Silver Bay	1	Coal	85	851	LSD	90	CUECost	43,277,712	3,894	10,377	766	13,549	3,465	12,918	766	808	150-16041
								IPM	17,737	808	3,465	766	4,524					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	58,235	4,195	12,918	808	15,979					
								IPM	33,215	1,156	6,132	808	7,585					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**85**	**851**									**3,465**	**12,918**	**766**	**808**	**922-16041**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Northshore/Silver Bay	1	Coal	85	1122	SCR	90	CUECost	11,870	849	2,627	1,010	2,602	322	2,627	16	40	200-2602
								IPM	8,498	56	1,199	1,010	1,187					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,758	205	468	393	1,192					
								IPM	2,160	32	322	393	821					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	3,668	82	632	393	1,609					
								IPM	2,546	39	381	393	971					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,912	844	1,430	617	2,317					
								IPM	-	-	-	617	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**85**	**1122**									**322**	**2,627**	**16**	**40**	**821-2322**

Table C-9. Virginia Public Utilities Commission Facility (Minnesota)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Virginia PUC	7	Coal	10	584	LSD	90	CUECost	30,787	1,616	6,228	525	11,859	6,228	8,933	525	554	150-16116
								IPM	-	-	-	525	-					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	44,821	2,219	8,933	554	16,116					
								IPM	-	-	-	554	-					
								STAPPA	-	-	-	-	200-5000					
		9	Coal	10	584	LSD	90	CUECost	30,787	1,616	6,228	525	11,859	6,228	8,933	525	554	150-16116
								IPM	-	-	-	525	-					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	44,821	2,219	8,933	554	16,116					
								IPM	-	-	-	554	-					
								STAPPA	-	-	-	-	200-5000					
		10	Coal	10	12,606	LSD	90	CUECost	30,787	1,616	6,228	11,346	549	6,228	8,933	11,346	11,976	150-922
								IPM	-	-	-	11,346	-					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	44,821	2,219	8,933	11,976	-					
								IPM	-	-	-	11,976	-					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**30**	**13,773**									**18,684**	**26,800**	**12,396**	**13,085**	**1507-2048**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Virginia PUC	7	Coal	10	125	SCR	90	CUECost	4,188	180	743	113	6,589	143	743	44	113	200-9011
								IPM	3,254	68	505	113	4,481					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,259	115	284	44	6,477					
								IPM	1,322	67	245	44	5,584					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	913	20	143	44	3,264					
								IPM	-	-	-	44	-					
								STAPPA	-	-	-		200-1000					
						NGR	55	CUECost	2,270	316	621	69	9,011					
								IPM	-	-	-	69	-					
								STAPPA	-	-	-	-	500-2000					
		9	Coal	10	125	SCR	90	CUECost	4,188	180	743	113	6,589	143	743	44	113	200-9011
								IPM	3,254	68	505	113	4,481					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,259	115	284	44	6,477					
								IPM	1,322	67	245	44	5,584					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	913	20	143	44	3,264					
								IPM	-	-	-	44	-					
								STAPPA	-	-	-		200-1000					
						NGR	55	CUECost	2,270	316	621	69	9,011					
								IPM	-	-	-	69	-					
								STAPPA	-	-	-	-	500-2000					

Table C-9. Virginia Public Utilities Commission Facility (Minnesota)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		10	Coal	10	0	SCR	90	CUECost	4,188	180	743	0	-	108	743	0	0	-
								IPM	-	-	-	0	-					
								STAPPA	-	-	-	-	-					
						SNCR	35	CUECost	1,259	115	284	0	-					
								IPM	720	11	108	0	-					
								STAPPA	-	-	-	-	-					
						LNB	35	CUECost	913	20	143	0	-					
								IPM	-	-	-	0	-					
								STAPPA	-	-	-	-	-					
						NGR	55	CUECost	2,270	316	621	0	-					
								IPM	-	-	-	0	-					
								STAPPA	-	-	-	-	-					
	Plant Total			**30**	**251**									**394**	**2,229**	**88**	**226**	**4495-9884**

Table C-10. Dairyland Power Coop/Alma Facility (Wisconsin)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Dairylan	1	Coal	18	1,384	LSD	90	CUECost	33,226	2,297	7,274	1,245	5,841	2,748	9,953	1,245	1,315	150-7571
								IPM	12,606	859	2,748	1,245	2,206					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	47,057	2,904	9,953	1,315	7,571					
								IPM	25,663	1,101	4,945	1,315	3,762					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	18	1,165	LSD	90	CUECost	33,226	2,213	7,190	1,048	6,858	2,701	9,874	1,048	1,107	150-8922
								IPM	12,606	813	2,701	1,048	2,576					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	47,057	2,825	9,874	1,107	8,922					
								IPM	25,663	1,054	4,899	1,107	4,426					
								STAPPA	-	-	-	-	200-5000					
		3	Coal	22	1,396	LSD	90	CUECost	34,312	2,416	7,556	1,256	6,016	2,986	10,284	1,256	1,326	150-7757
								IPM	13,805	918	2,986	1,256	2,378					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	48,384	3,036	10,284	1,326	7,757					
								IPM	27,487	1,184	5,302	1,326	3,999					
								STAPPA	-	-	-	-	200-5000					
		4	Coal	57	2,415	LSD	90	CUECost	42,672	4,086	10,478	2,174	4,820	5,090	13,325	2,174	2,295	150-5807
								IPM	22,357	1,741	5,090	2,174	2,341					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	57,570	4,701	13,325	2,295	5,807					
								IPM	39,561	2,188	8,114	2,295	3,536					
								STAPPA	-	-	-	-	200-5000					
		5	Coal	77	3,514	LSD	90	CUECost	43,802	4,382	10,944	3,163	3,460	6,175	14,097	3,163	3,338	150-4223
								IPM	26,064	2,271	6,175	3,163	1,953					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	60,464	5,039	14,097	3,338	4,223					
								IPM	44,421	2,798	9,453	3,338	2,832					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**192**	**9,874**									**19,701**	**57,533**	**8,886**	**9,380**	**2217-6134**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reductio	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Dairylan	1	Coal	18	316	SCR	90	CUECost	5,047	244	922	285	3,238	152	1,336	111	285	200-7682
								IPM	5,178	221	917	285	3,223					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,301	146	321	111	2,900					
								IPM	1,675	231	456	111	4,119					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	970	22	152	111	1,373					
								IPM	1,214	31	194	111	1,753					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	2,548	994	1,336	174	7,682					
								IPM	-	-	-	174	-					
								STAPPA	-	-	-	-	500-2000					

Table C-10. Dairyland Power Coop/Alma Facility (Wisconsin)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		2	Coal	18	266	SCR	90	CUECost	5,047	242	920	240	3,840	152	1,226	93	240	200-8370
								IPM	5,178	192	888	240	3,705					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,300	139	314	93	3,369					
								IPM	1,675	198	423	93	4,544					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	970	22	152	93	1,631					
								IPM	1,214	29	192	93	2,061					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	2,548	883	1,226	146	8,370					
								IPM	-	-	-	146	-					
								STAPPA	-	-	-	-	500-2000					
		3	Coal	22	319	SCR	90	CUECost	5,662	290	1,051	287	3,662	173	1,411	112	287	200-8043
								IPM	5,908	224	1,018	287	3,547					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,349	148	330	112	2,953					
								IPM	1,792	234	475	112	4,257					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	1,105	25	173	112	1,552					
								IPM	1,363	33	216	112	1,939					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	2,661	1,053	1,411	175	8,043					
								IPM	-	-	-	175	-					
								STAPPA	-	-	-	-	500-2000					
		4	Coal	57	773	SCR	90	CUECost	10,041	697	2,046	696	2,942	322	2,973	271	696	200-6993
								IPM	11,888	479	2,076	696	2,985					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,700	227	456	271	1,684					
								IPM	2,567	537	882	271	3,259					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,051	46	322	271	1,189					
								IPM	-	-	-	271	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,418	2,513	2,973	425	6,993					
								IPM	-	-	-	425	-					
								STAPPA	-	-	-	-	500-2000					
		5	Coal	77	1,124	SCR	90	CUECost	11,907	922	2,522	1,012	2,492	391	4,119	394	1,012	200-6660
								IPM	14,851	676	2,672	1,012	2,640					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,856	288	538	394	1,366					
								IPM	2,880	787	1,174	394	2,984					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,494	56	391	394	994					
								IPM	-	-	-	394	-					
								STAPPA	-	-	-		200-1000					
						NGR	55	CUECost	3,775	3,611	4,119	618	6,660					
								IPM	-	-	-	618	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**192**	**2,799**									**1,190**	**11,065**	**980**	**2,519**	**1556-4392**

Table C-11. Xcel Energy/Bay Front Facility (Wisconsin)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Xcel Energ	1	Coal	22	1,890	LSD	90	CUECost	37,322	2,701	8,291	1,701	4,876	2,953	11,074	1,701	1,795	150-6169
								IPM	13,843	879	2,953	1,701	1,736					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	51,934	3,294	11,074	1,795	6,169					
								IPM	27,544	1,146	5,272	1,795	2,937					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	22	1,890	LSD	90	CUECost	36,222	2,666	8,092	1,701	4,758	2,992	10,865	1,701	1,795	150-6053
								IPM	13,843	919	2,992	1,701	1,760					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	50,684	3,272	10,865	1,795	6,053					
								IPM	27,544	1,186	5,312	1,795	2,959					
								STAPPA	-	-	-	-	200-5000					
		5	Coal	30	1,478	LSD	90	CUECost	36,662	2,553	8,045	1,330	6,047	3,457	10,888	1,330	1,404	150-7753
								IPM	16,182	1,033	3,457	1,330	2,598					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	51,173	3,222	10,888	1,404	7,753					
								IPM	30,991	1,348	5,991	1,404	4,266					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**74**	**5,257**									**9,402**	**32,826**	**4,731**	**4,994**	**1987-6573**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Xcel Energ	1	Coal	22	509	SCR	90	CUECost	7,479	443	1,448	458	3,163	173	1,777	178	458	200-6350
								IPM	5,932	199	996	458	2,175					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,518	192	396	178	2,223					
								IPM	1,796	206	447	178	2,510					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	1,105	25	173	178	973					
								IPM	-	-	-	178	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	2,661	1,419	1,777	280	6,350					
								IPM	-	-	-	280	-					
								STAPPA	-	-	-	-	500-2000					
		2	Coal	22	447	SCR	90	CUECost	6,757	384	1,292	402	3,213	173	1,777	156	402	200-7227
								IPM	5,932	223	1,021	402	2,537					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,437	168	361	156	2,310					
								IPM	1,796	233	475	156	3,036					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	1,105	25	173	156	1,107					
								IPM	-	-	-	156	-					
								STAPPA	-	-	-	-	200-1000					

Table C-11. Xcel Energy/Bay Front Facility (Wisconsin)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
						NGR	55	CUECost	2,661	1,419	1,777	246	7,227					
								IPM	-	-	-	246	500-2000					
								STAPPA	-	-	-	-	1,285					
		5	Coal	30	517	SCR	90	CUECost	7,216	411	1,381	466	2,966	212	1,505	181	466	200-5287
								IPM	7,439	229	1,229	466	2,640					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,515	188	392	181	2,165					
								IPM	1,582	419	631	181	3,486					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	1,352	30	212	181	1,170					
								IPM	-	-	-	181	-					
								STAPPA	-	-	-	181	200-1000					
						NGR	55	CUECost	2,862	1,120	1,505	285	5,287					
								IPM	-	-	-	285	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**74**	**1,473**									**558**	**5,058**	**516**	**1,326**	**1083-3815**

Table C-12. Alliant Energy-Wisconsin Power/Edgewater Facility (Wisconsin)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Alliant Ene	3	Coal	75	1,864	LSD	90	CUECost	47,351	5,328	12,421	1,677	7,406	5,955	14,711	1,677	1,770	150-8310
								IPM	25,747	2,098	5,955	1,677	3,550					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	60,864	5,593	14,711	1,770	8,310					
								IPM	44,012	2,618	9,211	1,770	5,203					
								STAPPA	-	-	-	-	200-5000					
		4	Coal	334	8,277	LSD	90	CUECost	86,380	17,366	30,306	7,449	4,068	17,153	31,414	7,449	7,863	150-4068
								IPM	63,174	7,690	17,153	7,449	2,303					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	98,542	16,653	31,414	7,863	3,995					
								IPM	91,600	8,963	22,684	7,863	2,885					
								STAPPA	-	-	-	-	200-5000					
		5	Coal	422	10,672	LSD	90	CUECost	87,931	13,842	27,014	9,605	2,813	19,892	30,888	9,605	10,138	150-3047
								IPM	73,892	8,823	19,892	9,605	2,071					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	107,638	14,764	30,888	10,138	3,047					
								IPM	101,846	10,432	25,689	10,138	2,534					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**831**	**20,812**									**43,000**	**77,013**	**18,731**	**19,771**	**2296-3895**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Alliant Ene	3	Coal	75	865	SCR	90	CUECost	11,459	844	2,384	779	3,061	497	3,501	303	779	200-7355
								IPM	14,589	590	2,550	779	3,275					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,815	253	497	303	1,641					
								IPM	2,337	1,233	1,547	303	5,109					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	3,382	76	530	303	1,751					
								IPM	-	-	-	303	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,743	2,998	3,501	476	7,355					
								IPM	-	-	-	476	-					
								STAPPA	-	-	-	-	500-2000					
		4	Coal	334	3,285	SCR	90	CUECost	28,738	3,183	7,045	2,957	2,383	1,232	14,090	1,150	2,957	200-7797
								IPM	43,182	2,370	8,174	2,957	2,764					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,322	785	1,232	1,150	1,071					
								IPM	4,382	6,012	6,601	1,150	5,741					
								STAPPA	-	-	-	-	800-1500					

Table C-12. Alliant Energy-Wisconsin Power/Edgewater Facility (Wisconsin)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
						LNB	35	CUECost	8,929	200	1,400	1,150	1,218					
								IPM	-	-	-	1,150	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	8,058	13,007	14,090	1,807	7,797					
								IPM	-	-	-	1,807	-					
								STAPPA	-	-	-	-	500-2000					
		5	Coal	422	1,971	SCR	90	CUECost	33,963	3,698	8,263	1,774	4,659	863	16,789	690	1,774	200-15491
								IPM	51,214	2,727	9,610	1,774	5,419					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,533	388	863	690	1,251					
								IPM	5,481	3,792	4,529	690	6,566					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	7,536	169	1,182	690	1,713					
								IPM	-	-	-	690	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	9,791	15,474	16,789	1,084	15,491					
								IPM	-	-	-	1,084	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**831**	**6,121**									**2,592**	**34,380**	**2,142**	**5,509**	**1210-6240**

Table C-13. Alliant Energy-Wisconsin Power/Nelson Dewey Facility (Wisconsin)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Alliant Energy/N	1	Coal	108	4,206	LSD	90	CUECost	54,250	8,018	16,145	3,786	4,265	8,642	17,324	3,786	3,996	150-4335
								IPM	36,950	3,107	8,642	3,786	2,283					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	66,535	7,357	17,324	3,996	4,335					
								IPM	60,457	3,864	12,921	3,996	3,233					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	111	4,127	LSD	90	CUECost	54,432	7,949	16,103	3,714	4,336	8,738	17,320	3,714	3,920	150-4418
								IPM	37,434	3,131	8,738	3,714	2,353					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	66,701	7,328	17,320	3,920	4,418					
								IPM	61,054	3,898	13,044	3,920	3,327					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**219**	**8,333**									**17,381**	**17,320**	**7,500**	**7,916**	**2318-2199**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Alliant Energy/N	1	Coal	108	1,262	SCR	90	CUECost	14,058	1,159	3,049	1,136	2,684	487	4,904	442	1,136	200-7066
								IPM	18,912	849	3,391	1,136	2,986					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,033	326	599	442	1,357					
								IPM	2,716	1,871	2,236	442	5,063					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	3,108	70	487	442	1,103					
								IPM	-	-	-	442	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	4,294	4,327	4,904	694	7,066					
								IPM	-	-	-	694	-					
								STAPPA	-	-	-	-	500-2000					
		2	Coal	111	1,238	SCR	90	CUECost	14,135	1,161	3,061	1,114	2,747	496	4,830	433	1,114	200-7093
								IPM	19,272	850	3,440	1,114	3,087					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,039	322	596	433	1,375					
								IPM	2,746	1,871	2,240	433	5,171					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	3,163	71	496	433	1,145					
								IPM	-	-	-	433	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	4,343	4,246	4,830	681	7,093					
								IPM	-	-	-	681	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**219**	**2,500**									**983**	**9,734**	**875**	**2,250**	**1124-4326**

Table C-14. Boise Cascade Corporation (Minnesota)

Costs of SO2 Controls for ICIs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost-Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	Boise Cascade Corp.	2	Gas	38	48	LSD	90	CUECost	51,688	3,169	10,912	43	254,398	3,966	10,912	43	45	92472-242492
								IPM	18,130	1,373	4,089	43	95,333					
								Khan (2003)*	17,294	1,376	3,966	43	92,472					
								STAPPA	-	-	-	-	1,011					
						LSFO	95	CUECost	32,346	2,199	7,044	45	155,586					
								IPM	33,769	1,730	6,789	45	149,938					
								Khan (2003)*	17,294	1,376	3,966	45	87,605					
								STAPPA	-	-	-	-	1,011					
	Plant Total			**38**	**48**									**3,966**	**10,912**	**43**	**45**	**92472-242492**

Costs of NOx Controls for ICIs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost-Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	Boise Cascade Corp.	1	Gas	38	104	SCR	80	CUECost	7,076	398	1,349	84	16,146	120	2,769	37	81	424-43450
								IPM	2,768	129	501	84	5,990					
								Khan (2003)*	2,485	238	572	84	6,847					
								STAPPA	-	-	-	-	1,354					
						SNCR	50	CUECost	1,366	116	299	52	5,733					
								IPM	1,353	219	401	52	7,678					
								Khan (2003)*	1,307	299	475	52	9,094					
								STAPPA	-	-	-	-	2,193					
						LNB	35	CUECost	2,174	49	341	37	9,322					
								IPM	1,023	2	139	37	3,805					
								Khan (2003)*	792	61	167	37	4,569					
								STAPPA	-	-	-		424					
						NGR	61	CUECost	3,041	2,360	2,769	64	43,450					
								IPM	-	-	-	64	-					
								Khan (2003)*	446	61	120	64	1,891					
								STAPPA	-	-	-	-	-					

Table C-14. Boise Cascade Corporation (Minnesota)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost-Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		2	Gas	38	331	SCR	90	CUECost	7,331	421	1,406	265	5,307	169	1,406	116	291	424-27803
								IPM	2,749	127	497	265	1,875					
								Khan (2003)*	2,511	241	579	265	2,185					
								STAPPA	-	-	-	-	1,354					
						SNCR	35	CUECost	1,448	159	354	166	2,137					
								IPM	1,347	217	398	166	2,401					
								Khan (2003)*	1,321	304	482	166	2,908					
								STAPPA	-	-	-	-	2,193					
						LNB	35	CUECost	2,159	48	339	37	9,258					
								IPM	2	1,016	1,017	37	27,803					
								Khan (2003)*	801	61	169	37	4,623					
								STAPPA	-	-	-		424					
		3	Gas	35	25	SCR	90	CUECost	6,669	361	1,257	20	62,895	117	1,652	9	19	797-108392
								IPM	2,624	97	450	20	22,500					
								Khan (2003)*	2,413	230	554	20	27,716					
								STAPPA	-	-	-	-	2,330					
						SNCR	35	CUECost	1,322	101	279	12	22,303					
								IPM	1,307	96	271	12	21,728					
								Khan (2003)*	1,269	287	458	12	36,626					
								STAPPA	-	-	-	-	3,116					
						LNB	35	CUECost	2,061	46	323	9	36,942					
								IPM	1,550	28	236	9	27,018					
								Khan (2003)*	769	58	162	9	18,501					
								STAPPA					797					
						NGR	61	CUECost	2,975	1,252	1,652	15	108,392					
								IPM	-	-	-	15	-					
								Khan (2003)*	433	58	117	15	7,648					
								STAPPA	-	-	-	-	-					
	Plant Total			**76**	**436**									**406**	**5,827**	**161**	**392**	**2519-14849**

* "Total O&M Costs" for Khan (2003) also includes annual costs (e.g., annual catalyst replacement, fuel costs). For all other models "Total O&M Costs" do not contain any annual costs.

Table C-15. CUECost Example - Input Data for Analysis (JH Campbell, Michigan)

APC Technology Choices

Description	Units	Suggested Range	Default Values	Boiler 1	Boiler 2	Boiler 3	Boiler 3	Boiler 3
FGD Process	Integer	1 or 2	1	1	2	1	2	1
(1 = LSFO, 2 = LSD)								
Particulate Control	Integer	1 or 2	1	1	1	1	1	1
(1 = Fabric Filter, 2 = ESP)								
NOx Control	Integer	1 - 4	1	1	2	1	2	4
(1 = SCR, 2 = SNCR, 3 = LNBs, 4 = NGR)								

INPUTS

Description	Units	Range	Default Values	Boiler 1	Boiler 2	Boiler 3	Boiler 3	Boiler 3
General Plant Technical Inputs								
Location - State	Abbrev.	All States	PA	MI	MI	MI	MI	MI
MW Equivalent of Flue Gas to Control System	MW	100-2000	500	260	355	820	820	820
Net Plant Heat Rate (w/o APC)	Btu/kWhr		10,500	13,269	11,243	11,814	11,814	11,814
Plant Capacity Factor	%	40-90%	65%	77%	81%	77%	77%	77%
Percent Excess Air in Boiler	%		120%	120%	120%	120%	120%	120%
Air Heater Inleakage	%		12%	12%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F		300	300	300	300	300	300
Inlet Air Temperature	°F		80	80	80	80	80	80
Ambient Absolute Pressure	In. of Hg		29.4	29.4	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O		-12	-12	-12	-12	-12	-12
Moisture in Air	lb/lb dry air		0.013	0.013	0.013	0.013	0.013	0.013
Ash Split:								
Fly Ash	%		80%	80%	80%	80%	80%	80%
Bottom Ash	%		20%	20%	20%	20%	20%	20%
Seismic Zone	Integer	1-5	1	1	1	1	1	1
Retrofit Factor	Integer	1.0-3.0	1.3	1.3	1.3	1.3	1.3	1.3
(1.0 = new, 1.3 = medium, 1.6 = difficult)								
Select Coal	Integer	1-8	1	8	8	8	8	8
Is Selected Coal a Powder River Basin Coal?	Yes / No	See Column K	Yes	No	No	No	No	No

Coals Available in Library

Coal 1, Wyoming PRB: 8,227 Btu, 0.37% S, 5.32% ash
Coal 2, Armstrong, PA: 13,100 Btu, 2.6% S, 9.1% ash
Coal 3, Jefferson, OH: 11,922 Btu, 3.43% S, 13% ash
Coal 4, Logan, WV: 12,058 Btu, 0.89% S, 16.6% ash
Coal 5, No. 6 Illinois: 10,100 Btu, 4% S, 16% ash
Coal 6, Rosebud, MT: 8,789 Btu, 0.56% S, 8.15% ash
Coal 7, Lignite, ND: 7,500 Btu, 0.94% S, 5.9% ash
Coal 8, "User Specified": 12,062 Btu, 1% S, 16.6% ash

Description	Units	Range	Default Values	Boiler 1	Boiler 2	Boiler 3	Boiler 3	Boiler 3
Economic Inputs								
Cost Basis -Year Dollars	Year		1998	2005	2005	2005	2005	2005
Sevice Life (levelization period)	Years		30	15	15	15	15	15
Inflation Rate	%		3.00%	3.99%	3.99%	3.99%	3.99%	3.99%
After Tax Discount Rate (current $'s)	%		9.20%	9.20%	9.20%	9.20%	9.20%	9.20%
AFDC Rate (current $'s)	%		10.80%	10.80%	10.80%	10.80%	10.80%	10.80%
First-year Carrying Charge (current $'s)	%		22.30%	14.98%	14.98%	14.98%	14.98%	14.98%
Levelized Carrying Charge (current $'s)	%		16.90%	16.90%	16.90%	16.90%	16.90%	16.90%
First-year Carrying Charge (constant $'s)	%		15.70%	15.70%	15.70%	15.70%	15.70%	15.70%
Levelized Carrying Charge (constant $'s)	%		11.70%	11.70%	11.70%	11.70%	11.70%	11.70%
Sales Tax	%		6%	6%	6%	6%	6%	6%
Escalation Rates:								
Consumables (O&M)	%		3%	3%	3%	3%	3%	3%
Capital Costs:								
Is Chem. Eng. Cost Index available?	Yes / No		Yes	Yes	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer		388	468.3	468.3	468.3	468.3	468.3
If "No" input escalation rate.	%		3%	3%	3%	3%	3%	3%
Construction Labor Rate	$/hr		$35	$32	$32	$32	$32	$32
Prime Contractor's Markup	%		3%	3%	3%	3%	3%	3%
Operating Labor Rate	$/hr		$30	$31	$31	$31	$31	$31
Power Cost	Mills/kWh		25	68.3	68.3	68.3	68.3	68.3
Steam Cost	$/1000 lbs		3.5	7.44	7.44	7.44	7.44	7.44
Limestone Forced Oxidation (LSFO) Inputs								
SO2 Removal Required	%	90-98%	95%	95%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	95-160	125	125	125	125	125	125
Design Scrubber with Dibasic Acid Addition?	Integer	1 or 2	2	2	2	2	2	2
(1 = yes, 2 = no)								
Adiabatic Saturation Temperature	°F	100-170	127	127	127	127	127	127

Table C-15. CUECost Example - Input Data for Analysis (JH Campbell, Michigan)

Reagent Feed Ratio	Factor	1.0-2.0	1.05	1.05	1.05	1.05	1.05	1.05
(Mole CaCO3 / Mole SO2 removed)								
Scrubber Slurry Solids Concentration	Wt. %		15%	15%	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	1,2,3	1	1	1	1	1	1
(1 = stacking, 2 = landfill, 3 = wallboard)								
Number of Absorbers	Integer	1-6	1	1	1	1	1	1
(Max. Capacity = 700 MW per absorber)								
Absorber Material	Integer	1 or 2	1	1	1	1	1	1
(1 = alloy, 2 = RLCS)								
Absorber Pressure Drop	in. H2O		6	6	6	6	6	6
Reheat Required ?	Integer	1 or 2	1	1	1	1	1	1
(1 = yes, 2 = no)								
Amount of Reheat	°F	0-50	25	25	25	25	25	25
Reagent Bulk Storage	Days		60	60	60	60	60	60
Reagent Cost (delivered)	$/ton		$15	$15	$15	$15	$15	$15
Landfill Disposal Cost	$/ton		$30	$30	$30	$30	$30	$30
Stacking Disposal Cost	$/ton		$6	$6	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton		$2	$2	$2	$2	$2	$2
Maintenance Factors by Area (% of Installed Cost)								
Reagent Feed	%		5%	5%	5%	5%	5%	5%
SO2 Removal	%		5%	5%	5%	5%	5%	5%
Flue Gas Handling	%		5%	5%	5%	5%	5%	5%
Waste / Byproduct	%		5%	5%	5%	5%	5%	5%
Support Equipment	%		5%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)								
Reagent Feed	%		20%	20%	20%	20%	20%	20%
SO2 Removal	%		20%	20%	20%	20%	20%	20%
Flue Gas Handling	%		20%	20%	20%	20%	20%	20%
Waste / Byproduct	%		20%	20%	20%	20%	20%	20%
Support Equipment	%		20%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)								
Reagent Feed	%		10%	10%	10%	10%	10%	10%
SO2 Removal	%		10%	10%	10%	10%	10%	10%
Flue Gas Handling	%		10%	10%	10%	10%	10%	10%
Waste / Byproduct	%		10%	10%	10%	10%	10%	10%
Support Equipment	%		10%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)								
Reagent Feed	%		10%	10%	10%	10%	10%	10%
SO2 Removal	%		10%	10%	10%	10%	10%	10%
Flue Gas Handling	%		10%	10%	10%	10%	10%	10%
Waste / Byproduct	%		10%	10%	10%	10%	10%	10%
Support Equipment	%		10%	10%	10%	10%	10%	10%

Lime Spray Dryer (LSD) Inputs

SO2 Removal Required	%	90-95%	90%	90%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	100-170	127	127	127	127	127	127
Flue Gas Approach to Saturation	°F	10.-50	20	20	20	20	20	20
Spray Dryer Outlet Temperature	°F	110-220	147	147	147	147	147	147
Reagent Feed Ratio	Factor	Calc. Based on %S	0.90	1.04	1.04	1.04	1.04	1.04
(Mole CaO / Mole Inlet SO2)								
Recycle Rate	Factor	Calculated	30	7.5	7.5	7.5	7.5	7.5
(lb recycle / lb lime feed)								
Recycle Slurry Solids Concentration	Wt. %	10-50	35%	35%	35%	35%	35%	35%
Number of Absorbers	Integer	1-7	2	2	2	2	2	2
(Max. Capacity = 300 MW per spray dryer)								
Absorber Material	Integer	1 or 2	1	1	1	1	1	1
(1 = alloy, 2 = RLCS)								
Spray Dryer Pressure Drop	in. H2O		5	5	5	5	5	5
Reagent Bulk Storage	Days		60	60	60	60	60	60
Reagent Cost (delivered)	$/ton		$65	$65	$65	$65	$65	$65
Dry Waste Disposal Cost	$/ton		$30	$30	$30	$30	$30	$30
Maintenance Factors by Area (% of Installed Cost)								
Reagent Feed	%		5%	5%	5%	5%	5%	5%
SO2 Removal	%		5%	5%	5%	5%	5%	5%
Flue Gas Handling	%		5%	5%	5%	5%	5%	5%
Waste / Byproduct	%		5%	5%	5%	5%	5%	5%
Support Equipment	%		5%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)								
Reagent Feed	%		20%	20%	20%	20%	20%	20%
SO2 Removal	%		20%	20%	20%	20%	20%	20%
Flue Gas Handling	%		20%	20%	20%	20%	20%	20%
Waste / Byproduct	%		20%	20%	20%	20%	20%	20%
Support Equipment	%		20%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)								
Reagent Feed	%		10%	10%	10%	10%	10%	10%
SO2 Removal	%		10%	10%	10%	10%	10%	10%
Flue Gas Handling	%		10%	10%	10%	10%	10%	10%

Table C-15. CUECost Example - Input Data for Analysis (JH Campbell, Michigan)

Waste / Byproduct	%		10%	10%	10%	10%	10%	10%
Support Equipment	%		10%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)								
Reagent Feed	%		10%	10%	10%	10%	10%	10%
SO2 Removal	%		10%	10%	10%	10%	10%	10%
Flue Gas Handling	%		10%	10%	10%	10%	10%	10%
Waste / Byproduct	%		10%	10%	10%	10%	10%	10%
Support Equipment	%		10%	10%	10%	10%	10%	10%

NOx Control Inputs

Selective Catalytic Reduction (SCR) Inputs

NH3/NOX Stoichiometric Ratio	NH3/NOX	0.7-1.0	0.9	D	D	D	D	D
NOX Reduction Efficiency	Fraction	0.60-0.90	0.70	0.9	0.9	0.9	0.9	0.9
Inlet NOx	lbs/MMBtu		0.9	0.27	0.5225	0.3624	0.3624	0.3624
Space Velocity (Calculated if zero)	1/hr		0	D	D	D	D	D
Overall Catalyst Life	years	2-5	3	D	D	D	D	D
Ammonia Cost	$/ton		206	D	D	D	D	D
Catalyst Cost	$/ft3		356	D	D	D	D	D
Solid Waste Disposal Cost	$/ton		11.48	D	D	D	D	D
Maintenance (% of installed cost)	%		1.5%	D	D	D	D	D
Contingency (% of installed cost)	%		20%	D	D	D	D	D
General Facilities (% of installed cost)	%		5%	D	D	D	D	D
Engineering Fees (% of installed cost)	%		10%	D	D	D	D	D
Number of Reactors	integer		2	D	D	D	D	D
Number of Air Preheaters	integer		1	D	D	D	D	D

Selective NonCatalytic Reduction (SNCR) Inputs

Reagent	integer	1:Urea 2:Ammonia	1	D	D	D	D	D
Number of Injector Levels	integer		3	D	D	D	D	D
Number of Injectors	integer		18	D	D	D	D	D
Number of Lance Levels	integer		0	D	D	D	D	D
Number of Lances	integer		0	D	D	D	D	D
Steam or Air Injection for Ammonia	integer	1: Steam, 2: Air	1	D	D	D	D	D
NOX Reduction Efficiency	fraction	0.30-0.70	0.50	0.35	0.35	0.35	0.35	0.35
Inlet NOx	lbs/MMBtu		0.9	0.27	0.5225	0.3624	0.3624	0.3624
NH3/NOX Stoichiometric Ratio	NH3/NOX	0.8-2.0	1.2	D	D	D	D	D
Urea/NOX Stoichiometric Ratio	Urea/NOX	0.8-2.0	1.2	D	D	D	D	D
Urea Cost	$/ton		225	D	D	D	D	D
Ammonia Cost	$/ton		206	D	D	D	D	D
Water Cost	$/1,000 gal		0.4	D	D	D	D	D
Maintenance (% of installed cost)	%		1.5%	D	D	D	D	D
Contingency (% of installed cost)	%		20%	D	D	D	D	D
General Facilities (% of installed cost)	%		5%	D	D	D	D	D
Engineering Fees (% of installed cost)	%		10%	D	D	D	D	D

Low NOX Burner Technology Inputs

NOX Reduction Efficiency	fraction	0.15-0.60	0.35	D	D	D	D	D
Boiler Type	T:T-fired, W:Wall		T	D	D	D	D	D
Retrofit Difficulty	L:Low, A:Average, H:High		A	D	D	D	D	D
Maintenance Labor (% of installed cost)	%		0.8%	D	D	D	D	D
Maintenance Materials (% of installed cost)	%		1.2%	D	D	D	D	D

Natural Gas Reburning Inputs

NOX Reduction Efficiency	fraction	0.55-0.65	0.61	D	D	D	D	D
Gas Reburn Fraction	fraction	0.08 - 0.20	0.15	D	D	D	D	D
Waste Disposal Cost	$/ton		11.48	D	D	D	D	D
Natural Gas Cost	$/MMBtu		2.31	5	5	5	5	5
Maintenance (% of installed cost)	%		1.5%	D	D	D	D	D
Contingency (% of installed cost)	%		20%	D	D	D	D	D
General Facilities (% of installed cost)	%		2%	D	D	D	D	D
Engineering Fees (% of installed cost)	%		10%	D	D	D	D	D

Table C-16. CUECost Example - Results Output of Analysis (JH Campbell facility, Michigan)

Description	Units	Boiler 1	Boiler 2
SUMMARY OF COSTS			
APC Technologies			
NOx Control		SCR	SNCR
Particulate Control		PJFF	PJFF
SO2 Control		LSFO	LSD
NOx Control Costs		SCR	SNCR
Total Capital Requirement (TCR)	$	$29,284,539	$3,945,946
	$/kW	$112.6	$11.1
First Year Costs			
Fixed O&M	$	$407,517	$117,261
	$/kW-Yr	1.57	0.33
	Mills/kWH	0.23	0.05
	$/ton NOx removed	$109	$66
Variable O&M	$	$2,738,948	$1,306,727
	$/kW-Yr	10.53	3.68
	Mills/kWH	1.56	0.52
	$/ton NOx removed	$733	$739
Fixed Charges	$	$4,386,824	$591,103
	$/kW-Yr	16.87	1.67
	Mills/kWH	2.50	0.23
	$/ton NOx removed	$1,174	$334
TOTAL	$	$7,533,289	$2,015,091
	$/kW-Yr	28.97	5.68
	Mills/kWH	4.30	0.80
	$/ton NOx removed	$2,016	$1,140
Levelized Current Dollars			
Fixed O&M	$/kW-Yr	1.91	0.40
	Mills/kWH	0.28	0.06
	$/ton NOx removed	$133	$81
Variable O&M	$/kW-Yr	12.83	4.48
	Mills/kWH	1.90	0.63
	$/ton NOx removed	$893	$900
Fixed Charges	$/kW-Yr	19.03	1.88
	Mills/kWH	2.82	0.26
	$/ton NOx removed	$1,325	$377
TOTAL	$/kW-Yr	33.77	6.76
	Mills/kWH	5.01	0.95
	$/ton NOx removed	$2,350	$1,358
Levelized Constant Dollars			
Fixed O&M	$/kW-Yr	1.57	0.33
	Mills/kWH	0.23	0.05
	$/ton NOx removed	$109	$66
Variable O&M	$/kW-Yr	10.53	3.68
	Mills/kWH	1.56	0.52
	$/ton NOx removed	$733	$739
Fixed Charges	$/kW-Yr	13.18	1.30
	Mills/kWH	1.86	0.17
	$/ton NOx removed	$875	$249
TOTAL	$/kW-Yr	25.28	5.31
	Mills/kWH	3.66	0.74
	$/ton NOx removed	$1,717	$1,054
SO2 Control Costs		LSFO	LSD
Total Capital Requirement (TCR)	$	$93,491,840	$83,537,509
	$/kW	$360	$235
First Year Costs			
Fixed O&M	$	$5,268,554	$4,777,549
	$/kW-Yr	20.26	13.46
	Mills/kWH	3.00	1.90
	$/ton SO2 removed	$287.8	$226.3
Variable O&M	$	$5,040,781	$9,157,340
	$/kW-Yr	19.39	25.80
	Mills/kWH	2.87	3.64
	$/ton SO2 removed	$275.3	$433.8
Fixed Charges	$	$14,005,078	$12,513,919
	$/kW-Yr	53.87	35.25
	Mills/kWH	7.99	4.97
	$/ton SO2 removed	$764.9	$592.8
TOTAL	$	$24,314,412	$26,448,808
	$/kW-Yr	93.52	74.50
	Mills/kWH	13.86	10.50
	$/ton SO2 removed	$1,328	$1,253
Levelized Current Dollars			
Fixed O&M	$/kW-Yr	24.67	16.39
	Mills/kWH	3.66	2.31
	$/ton SO2 removed	$350.4	$275.6
Variable O&M	$/kW-Yr	23.61	31.41

Table C-16. CUECost Example - Results Output of Analysis (JH Campbell facility, Michigan)

	Mills/kWH	3.50	4.43
	$/ton SO2 removed	$335.2	$528.2
Fixed Charges	$/kW-Yr	60.77	39.77
	Mills/kWH	9.01	5.60
	$/ton SO2 removed	$863.0	$668.8
TOTAL	$/kW-Yr	109.05	87.56
	Mills/kWH	16.17	12.34
	$/ton SO2 removed	$1,548.6	$1,472.6
Levelized Constant Dollars			
Fixed O&M	$/kW-Yr	20.26	13.46
	Mills/kWH	3.00	1.90
	$/ton SO2 removed	$287.8	$226.3
Variable O&M	$/kW-Yr	19.39	25.80
	Mills/kWH	2.87	3.64
	$/ton SO2 removed	$275.3	$433.8
Fixed Charges	$/kW-Yr	42.07	27.53
	Mills/kWH	5.95	3.70
	$/ton SO2 removed	$570.0	$441.8
TOTAL	$/kW-Yr	81.72	66.79
	Mills/kWH	11.83	9.23
	$/ton SO2 removed	$1,133.1	$1,101.9

Due to the detailed nature of CUECost, the resulting cost effectiveness figures will not match exactly to what is reported in Section 5.1.6. However, the differences are insignificant and well within the +/- 30% range.

Contents

Table A-1. Summary of Current and Projected Emissions in the for States in the Study Region

	Estimated missions (tons/day)									
	EGU	ICI boilers	Recipro-cating engines	Turbines	Other point	Area sources	Onroad mobile sources	Nonroad mobile sources	Marine, aircraft, railroad	Total
SO2 in 2002										
Michigan	1,103	55			107	71		19	1	1,355
Minnesota	318	23			36	33		19	8	437
Wisconsin	602	149			14	9		13	13	800
3-State Subtotal	2,023	227			156	113		51	21	2,592
Illinois	1,310	161			213	11		31	0	1,725
Indiana	2,499	148			144	158		17	0	2,966
Iowa	412	88			50	2		12	8	571
Missouri	835	28			227	117		12	12	1,231
North Dakota	376	21			22	142		0	3	564
South Dakota	35	1			3	50		0	1	90
9-State Total	7,489	676			813	594		123	44	9,739
NOX in 2002										
Michigan	448	45	44	11	116	49	926	205	114	1,959
Minnesota	271	26	18	6	117	126	455	208	100	1,327
Wisconsin	294	65	8	2	24	32	481	145	79	1,129
3-State Subtotal	1,013	136	71	19	256	208	1,862	557	294	4,416
Illinois	712	101	112	14	129	62	890	324	277	2,622
Indiana	830	105	25	2	106	63	703	178	123	2,133
Iowa	254	45	26	2	39	7	304	174	89	941
Missouri	458	12	21	3	63	64	602	199	133	1,555
North Dakota	196	14	9	1	7	45	75	2	46	395
South Dakota	44	1	0	1	14	14	92	2	8	176
9-State Total	3,507	413	264	42	616	462	4,529	1,437	969	12,239
SO2 in 2018										
Michigan	1,093	51			134	68		0	1	1,347
Minnesota	236	22			48	34		4	2	346
Wisconsin	426	142			15	10		0	9	601
3-State Subtotal	1,755	215			196	112		4	11	2,294
Illinois	661	155			94	13		0	0	923
Indiana	1,033	138			152	153		3	0	1,479
Iowa	404	83			74	3		1	2	567
Missouri	770	26			395	120		3	7	1,321
North Dakota	298	20			32	137		4	0	491
South Dakota	33	2			4	51		3	0	94
9-State Total	4,952	641			948	588		19	20	7,168
NOX in 2018										
Michigan	273	43	41	11	133	54	385	94	110	1,145
Minnesota	115	25	18	6	134	136	205	175	54	867
Wisconsin	126	64	7	2	21	35	118	69	57	500
3-State Subtotal	514	132	66	20	287	225	708	338	222	2,512
Illinois	199	96	111	16	121	73	176	154	186	1,131
Indiana	262	100	23	2	101	69	105	141	84	887
Iowa	140	44	25	2	50	9	67	141	47	525
Missouri	213	12	20	3	75	74	119	161	99	777
North Dakota	196	14	8	1	12	50	34	204	24	545
South Dakota	40	1	0	1	22	15	42	148	5	273
9-State Total	1,564	400	254	45	669	515	1,250	1,288	666	6,650

Table A-2. Estimated Cost of Control for Facilities Subject to BART*

State	Source name	County	Baseline emissions (tons/year) SO2	NOX	Estimated reductions (%) SO2	NOX	Total annualized cost ($1000/year) SO2	NOX	Cost effectiveness ($/ton) SO2	NOX
Minnesota	Ipsat Inland (Mittal)	St. Louis	155	3,254	a	a	a	a	a	a
	EVTAC-Fairlane (United Taconite)	St. Louis	3,222	1,771	a	a	a	a	a	a
	National Steel (USS Keetac)	St. Louis	704	6,049	34	a	a	a	a	a
	Hibbing Taconite	St. Louis	593	6,203	0	13	a	a	a	a
	USS Minntac	St. Louis	1,946	14,924	0	10	a	612	a	705
	Northshore Mining^	Lake	2,291	3,649	0	40	a	640	a	1,439
North Dakota	Great River Energy – Coal Creek	McLean	34,578	11,114	78	30	7,870	420	531	248
	Basin Electric Power – Leland Olds	Mercer	88,462	16,136	93	44	49,000	9,300	963	1,770
	Great River Energy – Stanton	Mercer	8,592	2,139	90	26	9,330	1,275	300	504
	Minnkota Power – MR Young	Oliver	b	b	84	62	b	18,877	b	1,248

* Other State's BART analyses are not listed as they had not yet been completed at the time of this report

a The facility proposed that existing controls and operations were BART and therefore cost estimates are not included

b Information not available in facility's BART analysis

^ The facility proposed additional control as BART only for the power boiler at the facility, not the indurating furnaces. The power boiler is a CAIR unit

Table A-3. Projected Emission Reductions from EGUs as a Result of CAIR and Other Existing Regulations

	Baseline and projected emissions from EGU (1000 tons/year)				Emission reductions from 2002 (%)		
	2002	2012	2018	2026	2012	2018	2026
SO2 emissions							
Michigan	403	398	399	185	1	1	54
Minnesota	116	86	86	73	26	26	37
Wisconsin	220	153	155	137	31	29	38
3-state total	739	636	641	395	14	13	47
Illinois	478	239	241	214	50	50	55
Indiana	912	462	377	336	49	59	63
Iowa	150	144	147	146	4	2	3
Missouri	305	281	281	224	8	8	27
North Dakota	137	108	109	91	21	21	34
South Dakota	13	12	12	12	5	5	3
Region total	2,734	1,883	1,808	1,418	31	34	48
NOX emissions							
Michigan	164	91	100	93	45	39	43
Minnesota	99	41	42	43	58	58	57
Wisconsin	107	44	46	47	59	57	56
3-state total	370	176	188	182	52	49	51
Illinois	260	73	73	68	72	72	74
Indiana	303	141	95	93	54	68	69
Iowa	93	49	51	51	47	45	45
Missouri	167	81	78	75	52	53	55
North Dakota	72	72	72	72	0	0	0
South Dakota	16	15	15	15	9	9	8
Region total	1,280	606	571	556	53	55	57

Appendix B

Potential SO_2 and NO_X Regional Control Strategies and Unit-level Control Technologies

Contents

Appendix B-1. Control Strategies for Mobile Sources

Technology	Processes Covered	Estimated NOX Control Efficiency	Notes	Reference
Low NOX Calibration/Reflashing. Adopt regulations similar to the CARB Low NOx Software Upgrade program with a set phase in schedule that would require all low NOx rebuild engines to have low NOx rebuild kit installed by 2009.	1993 to 1998 MHDDV	24% reduction in tailpipe emissions	a	1, 2
	1993 to 1998 HHDDV	24% reduction in tailpipe emissions	a	1, 2
Emissions Inspections Program. Implement a State emissions inspection program for passenger vehicles and heavy duty diesel trucks.	1995 and older enhanced IM tailpipe test	8-9% annual inventory reduction	b, c	3
	1996 and newer OBDII equipped gasoline vehicles	0.1 gram/mile reduction for post-repair vehicles	b	4
	1997 and newer OBDII equipped light-duty diesel vehicles	0.6% reduction in tailpipe emissions	b	5
	2007 and newer heavy-duty diesel trucks (on the books)			6
	Smoking vehicles (identification, repair, and/or replace)	up to 53% decrease in NOX emissions for all vehicles participating in the program	aa	1, 21
Alternative Fuels. Increase use of alternative fuels including biodiesel-petroleum diesel blends, ethanol-gasoline blends, and liquid or compressed natural gas. (*Recommendation may be restricted to fuels already available in the Petroleum Administration for Defense District.)				
Use 7.0 RVP fuel in urban areas; e.g., Detroit area	LDGV			26
Fuel Switching: Biodiesel B100	HDDV	+10% pre-1998, +30% 98-04 increase in tailpipe emissions	d	7
Fuel Switching: Biodiesel B20	HDDV	+2% pre-1998, +4% 98-04 increase in tailpipe emissions	e	7

Appendix B-1. Control Strategies for Mobile Sources

Technology	Processes Covered	Estimated NOX Control Efficiency	Notes	Reference
Fuel Switching: Biodiesel B20	Bulldozer, Motor Grader	unknown	f	8
Fuel Switching: Biodiesel B30	Bulldozer, Motor Grader	unknown	g	8
Fuel Switching: Biodiesel B20	Locomotive (line haul or switching)	+5-6% increase in tailpipe emissions	h	9
Fuel Switching: Biodiesel B20	Marine Port applications	unknown	i	10
Use lower sulfur fuel: CARB Diesel*	Locomotive (line haul or switching)	1-2% reduction in tailpipe emissions	h, j	9
	Harbor craft	15% inventory reduction	k	18
	Large deep draft marine vessels	15% inventory reduction	k	18
Use lower sulfur fuel: Highway or ULSD*	Harbor craft (ferries, tugs)	15% inventory reduction	k	18
	Large deep draft marine vessels	15% inventory reduction	k	18
Increase use of E10	LDGV	+5% increase in tailpipe emissions	l	11, 12
Fuel Switching: Convert public fleets to Flex Fuel Vehicles fueled with E85.	LDGV	tailpipe control efficiency unavailable	l	12
Fuel Switching: LNG or CNG	LDGV	60% reduction in tailpipe emissions		13
Fuel Switching: LNG	Locomotive (line haul or switching)	tailpipe control efficiency unavailable		14
Fuel Switching: LNG or CNG	MDGV, HDGV	50% reduction in tailpipe emissions		13
Anti-Idling. Reduce idling emissions from heavy-duty diesel trucks and locomotives using truck stop electrification and locomotive anti-idling technology.	1993 to 1998 MHDDV	unknown	m, n	1
	Switching locomotives	50% reduction in tailpipe emissions	o	1
	Line-haul locomotives	75% reduction in tailpipe emissions	o	1

[continued]

Appendix B-1. Control Strategies for Mobile Sources

Technology	Processes Covered	Estimated NOX Control Efficiency	Notes	Reference
Fleet Modernization (all percentages are reductions in tailpipe emissions). Replace equipment or rebuild engines to meet new engine standards.				
Upgrade to 1990 Engine	MY 1989 and earlier HDDV	43% reduction	p	1
Upgrade to 2001/2 Engine	MY 1989 and earlier HDDV	63% reduction	p	1
	MY 1990 HDDV	33% reduction	p	1
	MY 1991-1997 HDDV	20% reduction	p	1
Upgrade to 2002/4 Engine	MY 1989 and earlier HDDV	78% reduction	p	1
	MY 1990 HDDV	66% reduction	p	1
	MY 1991-1997 HDDV	52% reduction	p	1
Upgrade to 2007 Engine	MY 1998-2001 HDDV	95% reduction	p	1
	MY 2002-2006 HDDV	92% reduction	p	1
Upgrade construction and agricultural equipment to Tier 2, 3, or 4	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks, Agricultural Tractors, Combines	Dependent on model year and horsepower. See Reference 11 for engine standard schematic.		1, 15
Fleet turnover to 2007 and newer engines (On the books)	HDDV	unknown		

[continued]

Appendix B-1. Control Strategies for Mobile Sources

Technology	Processes Covered	Estimated NOX Control Efficiency	Notes	Reference
Retrofit Technology (all percentages are reductions in tailpipe emissions). Install aftertreatment NOX controls on on-road heavy-duty diesel vehicles and off-road construction, cargo-handling, and marine equipment.				
Selective Catalytic Reduction (SCR)	MY pre-1989 through 2006 HDDV	up to 80% reduction		1, 16
	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	up to 80% reduction		1, 16
	Locomotive (line haul or switching)	90% reduction		16
	Agricultural Tractors, Combines	up to 80% reduction	q	1, 16
Lean NOX Catalyst (LNC) combined with Diesel Particulate Filter (DPF)	MY pre-1989 through 2006 HDDV	15-25% reduction	r	1, 16
LNC	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	15-25% reduction		1, 17
	Agricultural Tractors, Combines	15-25% reduction		1, 16
Exhaust Gas Recirculation (EGR) combined with DPF	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	up to 50% reduction	s	1, 16
	Agricultural Tractors, Combines	up to 50% reduction	s	1, 16
Diesel Oxidation Catalyst combined with SCR	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	up to 80% reduction	t	1, 16
	Agricultural Tractors, Combines	up to 80% reduction	t	1, 16
SCR combined with DPF	Excavators, Rubber Tire Loaders, Crawler Tractors/Dozers, Tractors/Loaders/Backhoes, Off-Highway Trucks	up to 80% reduction	u	1, 16
	Agricultural Tractors, Combines	up to 80% reduction	u	1, 16

[continued]

Appendix B-2. Control Strategies for EGUs

Technology	Processes Covered	Efficiency of Control	Notes	Reference
Baseline and On-the-books regional programs				
Baseline 2002: (MRPO average SO_2 is 1.16 lbs/mmBtu, NO_x is 0.43 lbs/mmBtu): NSPS; PSD/NSR; State RACT Rules; Title IV SO_2 Program	EGUs	MRPO average SO_2 is 1.16 lbs/mmBtu, NO_x is 0.43 lbs/mmBtu	bb	19
2009 On-the-Books measures: CAIR	EGUs	EPA CAIR levels are estimated at 0.13 lbs/mmBtu NOX and 0.26 lbs/mmBtu SO_2 in 2015.	bb	19, 22
2009 On-the-Books measures: CAIR -- Michigan Impacts	EGUs	EPA estimates a 10% reduction in SO_2 and a 29% reduction in NOX from 2003 levels.	bb	23
2009 On-the-Books measures: CAIR -- Minnesota Impacts	EGUs	EPA estimates a 36% reduction in SO_2 and a 59% reduction in NOX from 2003 levels.	bb	24
2009 On-the-Books measures: CAIR -- Wisconsin Impacts	EGUs	EPA estimates a 32% reduction in SO_2 and a 61% reduction in NOX from 2003 levels.	bb	25
Additional regional programs				
Adopt Emission Caps Based on "Retrofit SO_2 BACT Level" of 0.15 lbs/mmBtu by 2013 (with Interim Cap Based on 0.36 lbs/mmBtu in 2009)	EGUs	Additional 0.11 lbs/mmBtu reduction in SO_2 from original CAIR emissions cap	v	19
Adopt Emission Caps Based on "Retrofit NO_x BACT Level" of 0.10 lbs/mmBtu by 2013 (with Interim Cap Based on 0.15 lbs/mmBtu in 2009)	EGUs	Additional 0.03 lbs/mmBtu reduction in NOX from original CAIR emissions cap		19
Adopt Emission Caps Based on "SO_2 BACT Level for New Plants" of 0.10 lbs/mmBtu by 2013 (with Interim Cap Based on 0.24 lbs/mmBtu in 2009)	EGUs	Additional 0.16 lbs/mmBtu reduction in SO_2 from original CAIR emissions cap	w	19
Adopt Emission Caps Based on "NO_x BACT Level for New Plants" of 0.07 lbs/mmBtu by 2013 (with Interim Cap Based on 0.12 lbs/mmBtu in 2009)	EGUs	Additional 0.06 lbs/mmBtu reduction in NOX from original CAIR emissions cap		19
Replace old boilers to boost efficiency by 50-60%	EGUs	Not Available		19
Implement Consumer Education programs to promote energy efficiency and reduce demand.		Not Available		19

Appendix B-2. Control Strategies for EGUs

Technology	Processes Covered	Efficiency of Control	Notes	Reference
Fuel Options				
Use fuel oil with a sulfur content of 0.05% or less for all boiler sizes (<50 - >250 MmBtu/hr)	#1 and #2 fuel oil			26
Use fuel oil with a sulfur content of 0.5% or less	#4 and #6 fuel oil			26
Use coal with low sulfur content	Coal for units between 50-100 mmBtu/hr	2.0 lb/MmBtu or 30% SO2 reduction		26
Use coal with low sulfur content	Coal for units between 100-250 mmBtu/hr	1.2 lb/MmBtu or 85% SO2 reduction		26
Use coal with low sulfur content	Coal for units >250 MmBtu/hr	0.25 lb/MmBtu or 85% SO2 reduction		26
Retrofit Technologies for individual emission units				
Burner Modifications	Most units	10 to 30% NOx reduction		19
Fuel Reburn	Most units. Furnace height (residence time) may restrict some applications	20 to 30% NOx reduction for Fuel-Lean Gas Reburning (no OFA), and 30 to 60% reduction for conventional reburning.		19
Hydrocarbon-enhanced SNCR	Most units. Can use more NH3 with less slip.	40 to 60% NOx reduction		19
Low-NOx Burners	Most boilers already have LNB.	30 to 50% NOx reduction		19
Overfire Air	Most units. Furnace height may restrict some applications	20 to 40% NOx reduction		19
Oxygen-enhanced combustion modification	Best applied with new OFA system designed to achieve stoichiometric air-fuel ratio < 0.8.	30-50% beyond OFA		19
Rich Reagent Injection	Most units. Modeling required to determine injection locations.	20 to 30% additional NOx reduction beyond OFA.		19
Selective Catalytic Reduction (SCR)	Most units. Space availability may constrain some options. High sulfur fuels more challenging	70 to 90+% NOx reduction		19
Selective Non-catalytic Reduction (SNCR)	Most units. Residence time and temperature characteristics are important	25 to 50% NOx reduction, depending on the furnace temperature and time for reaction.		19

[continued]

Appendix B-2. Control Strategies for EGUs

Technology	Processes Covered	Efficiency of Control	Notes	Reference
Physical Coal Cleaning	Available for all units	10-40% SO2 reduction		19
Chemical Coal Cleaning	Available for all units	50-85% SO2 reduction		19
Switch to Low Sulfur Coal	Available for all units	50-80% SO2 reduction		19
Limestone forced oxidation system (LSFO)	Generally used for >100 MW units units firing high-sulfur (>2 percent) bituminous coals.	52 – 98% reduction in SO2, with median reduction of 90%; EPA used 95% in CAIR analysis		19
Magnesium enhanced lime system (MEL)	Generally used for 100-550 MW units units firing low-sulfur (<2 percent) bituminous, sub-bituminous, and lignite coals.	52 – 98% reduction in SO2, with median reduction of 90%; EPA used 96% for CAIR analysis		19
Lime spray dryer system (LSD)	Can be used for both low-and high-sulfur coals, depending on the economics of each application.	70 - 96% reduction in SO2, with median reduction of 90%; EPA used 90% for CAIR analysis		19
Dry or wet FGD	Coal-burning units >250 mmBtu/hr	90% SO2 reduction		26
Combustion Tuning	All units 50-100 mmBtu/hr	5-35% NOX reduction		26

[continued]

Appendix B-3. Control Strategies for ICI Boilers

Technology	Processes Covered	Efficiency of Control (% at the unit)	Notes	Reference
Baseline and On-the-books regional programs				
Baseline 2002: NSPS; PSD/NSR; State RACT Rules	ICI Boilers	NA	bb	20
2009 On-the-Books (OTB) measures: Enforcement settlements and Alcoa announced scrubbers	ICI Boilers	18% SO2 reduction from 2002 levels	bb	20
2009 OTB measures: NOx SIP Call for large boilers, enforcement settlements	ICI Boilers	3% NOX reduction from 2002 levels	bb	20
Additional regional programs				
OTB measures plus 40% SO2 Reduction and 60% Reduction (similar to NOx SIP Call) to All Medium and Large ICI Boilers	ICI Boilers	29% SO2 reduction and 19% NOX reduction from 2002 levels	x	20
OTB Measures plus Likely Controls to ICI Boilers subject to the proposed BART requirements Emission Reductions.	ICI Boilers	8% NOX reduction and 40% SO2 reduction from 2002 levels	y	20
OTB Measures plus 90% SO2 Reduction and 80% NOX reduction (similar to BART) to All Medium and Large ICI Boilers Emission Reductions.	ICI Boilers	66% SO2 reduction and 31% NOX reduction from 2002 levels	z	20
Fuel Options				
Use fuel oil with a sulfur content of 0.05% or less for all boiler sizes (<50 - >250 MmBtu/hr)	#1 and #2 fuel oil			26
Use fuel oil with a sulfur content of 0.5% or less	#4 and #6 fuel oil			26
Use coal with low sulfur content	Coal for units between 50-100 mmBtu/hr	2.0 lb/MmBtu or 30% SO2 reduction		26
Use coal with low sulfur content	Coal for units between 100-250 mmBtu/hr	1.2 lb/MmBtu or 85% SO2 reduction		26
Use coal with low sulfur content	Coal for units >250 MmBtu/hr	0.25 lb/MmBtu or 85% SO2 reduction		26

Appendix B-3. Control Strategies for ICI Boilers

Technology	Processes Covered	Efficiency of Control (% at the unit)	Notes	Reference
Retrofit Technologies for individual emission units				
LNB (Low NOX Burner)	Coal Sub-bituminous fueled boiler	51% NOX reduction		20
LNB + OFA (Over-fire air)	Coal Sub-bituminous fueled boiler	65% NOX reduction		20
	Coal Bituminous fueled boiler	51% NOX reduction		20
	Gas fueled boiler	60% NOX reduction		20
	Oil fueled boiler	30% NOX reduction		20
LNB + OFA + FGR (Flue Gas Recirculation)	Gas fueled boiler	80% NOX reduction		20, 26
LNB + OFA + FGR (0.5 lbs/mmBtu inlet NOx)	Oil fueled boiler	50% NOX reduction		20, 26
SCR	Coal fueled boiler	80% NOX reduction		20, 26
	Gas fueled boiler	80% NOX reduction		20, 26
	Oil fueled boiler	80% NOX reduction		20, 26
SNCR	Coal fueled boiler	40% NOX reduction		20, 26
	Oil fueled boiler	40% NOX reduction		20, 26
	Wood/Non-fossil solid fuel	not available		26
	Gas fueled boiler	40% NOX reduction		20
In-duct Dry Sorbent Injection (IDSI)	Coal High Sulfur fueled boiler	40% SO2 reduction		20
	Coal Low Sulfur fueled boiler	40% SO2 reduction		20
SDA	Coal fueled boiler	90% SO2 reduction		20
Wet FGD	Coal High Sulfur fueled boiler	90% SO2 reduction		20
	Coal Low Sulfur fueled boiler	90% SO2 reduction		20
	Oil fueled boiler	90% SO2 reduction		20
Water Injection	Gas fueled boiler	75% NOX reduction		26

[continued]

Appendix B-4. Control Strategies for Reciprocating Engines

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Low-Emission Combustion	Internal Combustion	80-90% reduction		27
Prestratified Charge	Internal Combustion	75-90% reduction		27
High Energy/Plasma Ignition Systems	Internal Combustion	80% reduction	cc	27
SCONOx Technology	Internal Combustion	95% reduction	dd	27
NOxTech System	Internal Combustion	90-95% reduction		27
High-pressure Fuel Injection	Internal Combustion	80% reduction		27
Air Fuel w/Ignition Retard	Internal Combustion - Gas	53 tons/30% reduction	hh	28, 29
Air Fuel w/Ignition Retard	IC Engines - Gas	53 tons/30% reduction	hh	28, 29
Air Fuel Ratio Adjustment	Internal Combustion - Gas	36 tons/20% reduction	hh	28, 29
Air Fuel Ratio Adjustment	IC Engines - Gas	38 tons/20% reduction	hh	28, 29
Ignition Retard	IC Engine - Oil	6 tons/25% reduction	hh	28, 29
Ignition Retard	IC Engines - Gas, Diesel, LPG	9 tons/25% reduction	hh	28, 29
L-E (Low Speed)	IC Engine - Gas	148 tons/87% reduction	hh	28, 29
L-E (Medium Speed)	IC Engine - Gas	98 tons/87% reduction	hh	28, 29
NSCR	IC Engine - Oil	19 tons/90% reduction	ee, hh	27, 28, 29
NSCR	IC Engine - Gas, Diesel, LPG	26 tons/90% reduction	ff, hh	27, 28, 29
SCR	IC Engine - Gas	150 tons/90% reduction	gg, hh	27, 28, 29
SCR	IC Engine - Gas, Diesel, LPG	23 tons/80% reduction	hh	27, 28, 29
SCR	IC Engine - Oil	17 tons/80% reduction	hh	27, 28, 29

Appendix B-5. Control Strategies for Turbines

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
External Flue Gas Recirculation	Turbine	N/A	ii	30
Overfire Air	Turbine	N/A		30
Low NOx Burners	Turbine	25-50% reduction		30
Selective Catalytic Reduction (High Dust)	Turbine	70-90% control efficiency	ii	30
Selective Catalytic Reduction (Low Dust)	Turbine	80-90% control efficiency		30
Selective Non-Catalytic Reduction	Turbine	25-50% control efficiency		30
Low Temperature Oxidation (Tri-NOx)	Turbine	99% control efficiency		30
Low Temperature Oxidation (LoTox)	Turbine	80-95% control efficiency		30
Non Selective Catalytic Reduction	Turbine	N/A	ii	30
Novel Multi-Pollutant Controls (Electro-Catalytic Oxidation)	Turbine	N/A		30
Novel Multi-Pollutant Controls (Pahlman Process)	Turbine	N/A	ii	30
SCONOx Technology	Gas Turbines	95% reduction		27
Dry Low NOx Combuster	Combustion Turbines - Natural Gas	102 tons/50% reduction	hh	28, 29
Dry Low NOx Combuster	Combustion Turbines - Natural Gas	102 tons/84% reduction	hh	28, 29
SCR w/Low NOx Burner	Combustion Turbines - Natural Gas	143 tons/94% reduction	hh	28, 29
SCR w/Steam Injection	Combustion Turbines - Natural Gas	145 tons/95% reduction	hh	28, 29
SCR w/Water Injection	Combustion Turbines - Natural Gas	145 tons/95% reduction	hh	28, 29
SCR w/Water Injection	Combustion Turbines - Oil	31 tons/90% reduction	hh	28, 29
SCR w/Water Injection	Combustion Turbines - Jet Fuel	13 tons/90% reduction	hh	28, 29
Steam Injection	Combustion Turbines - Natural Gas	119 tons/80% reduction	hh	28, 29
Water Injection	Combustion Turbines - Natural Gas	112 tons/76% reduction	hh	28, 29
Water Injection	Combustion Turbines - Oil	23 tons/68% reduction	hh	28, 29
Water Injection	Combustion Turbines - Jet Fuel	10 tons/68% reduction	hh	28, 29
Dry Low NOx Combuster	Combustion Turbines - Natural Gas	102 tons/50% reduction	hh	28, 29
Dry Low NOx Combuster	Combustion Turbines - Natural Gas	102 tons/84% reduction	hh	28, 29

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Floor housing system with stockpiling of manure	Storage and handling of poultry manure (solid)	N/A	jj	31
Cage housing system with conveyor belts	Storage and handling of poultry manure (solid)	N/A	jj	31
Cage housing system with deep pits	Storage and handling of poultry manure (solid)	N/A	jj	31
Lagoons/concrete tanks for storage of poultry manure	Storage of poultry manure (storage)	N/A	jj	31
Spread manure and incorporate within 3 days	Application of poultry manure (solid)	36 - 80% reduction	jj, kk	32
Spread manure and incorporate within 3 days	Application of dairy manure (solid and liquid)	70% reduction	jj, kk	32
Spread manure and incorporate within 3 days	Application of beef manure (solid and liquid)	36-70% reduction	jj, kk	32
Spread manure and incorporate within 3 days	Application of swine manure (solid and liquid)	36-70% reduction	jj, kk	32
Inject manure using tank wagon and incorporate with knives or disks	Application of dairy and beef manure (liquid)	N/A		33
Above-ground manure storage tanks	Storage of dairy and beef manure (solid and liquid)	N/A	ll	33
Walled enclosures to store manure	Storage of dairy and beef manure (solid and liquid)	N/A	mm	33
Outwinter cattle by rotating through pastures to "store" manure in frozen form until it can be used in the spring	Housing cattle (winter)	N/A		34
Outwinter cattle by keeping them outside in one paddock (sacrifice paddock) to store manure in one location	Housing cattle (winter)	N/A		34
Compost manure before applying	Treatment of livestock manure (solid and liquid)	N/A		35
Daily scraping and hauling of manure for collection and storage	Storage and handling of swine manure (solid)	42-63% reduction	jj, nn	36
Leaving manure to mix with bedding to form manure pack for collection and storage	Storage and handling of swine manure (solid)	33-50% reduction	jj, nn	36
Storing manure in lined pit	Storage and handling of swine manure (liquid)		jj, oo	36
Storing manure in above-ground storage facility	Storage and handling of swine manure (liquid)	25-50% reduction	jj, oo	36
Broadcasting manure w/incorporation into soil within 12 hours	Application of swine manure (solid)	80% reduction	jj, h1	36

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Broadcasting manure w/incorporation into soil within 4 days	Application of swine manure (solid)	40% reduction	jj, h1	36
Injection of manure with sweeps	Application of swine manure (liquid)	87% reduction	jj, h1	36
Injection of manure with knives	Application of swine manure (liquid)	62% reduction	jj, h1	36
Collection ponds to store manure	Storage and handling of swine manure (liquid)	N/A		37
Deep pits to store manure and minimize gas concentrations	Storage and handling of swine manure (solid)	N/A		37
Stockpile manure on concrete or clay pad	Storage and handling of swine manure (solid)	N/A		37
System than separates liquid and solid manure	Storage and handling of swine manure (solid)	N/A		37
Composting manure	Treatment of swine manure (liquid and solid)	N/A		37
Anaerobic lagoons and digesters to store and "treat" manure	Treatment of swine manure (liquid and solid)	N/A		37
Oxidation ditches and aerated lagoons to store and "treat" manure	Treatment of swine manure (liquid and solid)	N/A		37
Daily scraping and hauling of manure for collection and storage	Storage and handling of poultry manure (solid)	42-63% reduction	jj, nn	38
Leaving manure to mix with bedding to form manure pack for collection and storage	Storage and handling of poultry manure (solid)	33-50% reduction	jj, nn	38
Broadcasting manure w/incorporation into soil within 12 hours	Application of poultry manure (solid)	83% reduction	jj, h1	38
Broadcasting manure w/incorporation into soil within 4 days	Application of poultry manure (solid)	33% reduction	jj, h1	38

[continued]

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Daily scraping and hauling of manure for collection and storage	Storage and handling of dairy manure (solid)	42-62% reduction	jj, nn	39
Leaving manure to mix with bedding to form manure pack for collection and storage	Storage and handling of dairy manure (solid)	30-50% reduction	jj, nn	39
Storing manure in lined pit	Storage and handling of dairy manure (liquid)	25% reduction	jj, oo	39
Storing manure in above-ground storage facility	Storage and handling of dairy manure (liquid)	25-50% reduction	jj, oo	39
Broadcasting manure w/incorporation into soil within 12 hours	Application of dairy manure (solid)	75% reduction	jj, h1	39
Broadcasting manure w/incorporation into soil within 4 days	Application of dairy manure (solid)	50% reduction	jj, h1	39
Injection of manure with sweeps	Application of dairy manure (liquid)	86% reduction	jj, h1	39
Injection of manure with knives	Application of dairy manure (liquid)	71% reduction	jj, h1	39
Daily scraping and hauling of manure for collection and storage	Storage and handling of beef manure (solid)	42-63% reduction	jj, nn	40
Leaving manure to mix with bedding to form manure pack for collection and storage	Storage and handling of beef manure (solid)	33-50% reduction	jj, nn	40
Storing manure in lined pit	Storage and handling of beef manure (liquid)	25% reduction	jj, oo	40
Storing manure in above-ground storage facility	Storage and handling of beef manure (liquid)	25-50% reduction	jj, oo	40
Broadcasting manure w/incorporation into soil within 12 hours	Application of beef manure (solid)	87% reduction	jj, h1	40
Broadcasting manure w/incorporation into soil within 4 days	Application of beef manure (solid)	50% reduction	jj, h1	40
Injection of manure with sweeps	Application of beef manure (liquid)	56% reduction	jj, h1	40
Injection of manure with knives	Application of beef manure (liquid)	71% reduction	jj, h1	40
Best Management Practices		N/A		41
Manure Storage Covers	Storage of livestock manure (solid and liquid)	N/A		41
Manure Digesters (Biogas)	Handling of livestock manure (solid and liquid)	N/A		41
Animal Lot Increased Cleaning		N/A		41
Injection of manure into fields	Application of livestock manure (liquid)	N/A		41

[continued]

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Nutrient Management Plans	Housing, storage, handling, and application of livestock manure (solid and liquid)	N/A		41
Earthen storage	Storage of manure (solid and liquid)	N/A	qq	42
Clay-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Geomembrane-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Geosynthetic clay-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Concrete-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Manure storage structure	Storage of manure (solid and liquid)	N/A	qq	42
Clay-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Geomembrane-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Geosynthetic clay-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Concrete-lined impoundment	Storage of manure (solid and liquid)	N/A		42
Nitrification inhibitor	Handling of livestock manure (liquid)	N/A	ss	43
Minimize application on frozen or snow-covered ground	Application of livestock manure (solid and liquid)	N/A		44
Apply manure on crops that can use all of its nutrients	Application of livestock manure (solid and liquid)	N/A		44
Incorporate or inject manure within 72 hours using urease inhibitor	Application of livestock manure (solid and liquid)	N/A		44
Cover manure storage structures or use organic matter in bedding to form a crust cover	Storage of livestock manure (solid and liquid)	N/A		44
Divert urine away from feces	Handling of livestock manure (solid and liquid)	N/A		44
Incorporate manure	Application of dairy manure	10% reduction	jj, kk	44
Incorporate manure	Application of beef manure	10% reduction		44
Incorporate manure	Application of swine manure (solid)	15% reduction		44
Incorporate manure	Application of swine manure (liquid)	15% reduction	tt	44

[continued]

Appendix B-6. Control Strategies for Ammonia

Control Measure	Sources Covered	Estimated Efficiency (%)	Notes	References
Incorporate manure	Application of poultry manure	10% reduction	uu	44
Incorporate manure	Application of sheep manure (solid)	10% reduction		44
Incorporate manure	Application of horse manure (solid)	10% reduction		44
Solid and liquid separation system	Handling of liquid and solid manure	N/A	vv	45
Treat waste by mechanical, chemical, or biological means	Treatment of livestock manure (solid and liquid)	N/A		46, 47
Hopper to transfer manure	Handling of liquid and solid manure	N/A		48
Reception structure or tank to transfer manure	Handling of liquid and solid manure	N/A	ww	48
Piston pumps to transfer manure to storage or treatment structure	Handling of liquid and solid manure	N/A		48
Channels to transfer manure (gravity transfer)	Handling of liquid and solid manure	N/A	xx	48
Transfer pipes to transfer manure to storage or treatment structure	Handling of liquid and solid manure	N/A	xx	48
Pipelines (gravity transfer)	Handling of liquid and solid manure	N/A		48

[continued]

Appendix B-7. References for Control Strategies

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[continued]

Appendix B-8. Notes on Control Strategies

a. Implementation: use existing authorities like anti-tampering compliance authority, pursuing a mandatory program based on current draft OTC model rule, or working with engine manufacturers on a voluntary program.

b. Southeastern Wisconsin already requires tailpipe and OBDII inspections on passenger vehicles. This recommendation would expand the program to all of WI, re-start and expand the program in MN, and start a program in MI. Requires promulgation of State laws. (Similar measures were also mentioned in ENVIRON's phase I mobile source strategy

c. MOBILE5 estimates a 9% total emission inventory reduction with a fully implemented enhanced IM program. However, a NAS report in 2001 found that this may be an overestimation. The ENVIRON Phase I mobile source control measures report estimates an 8% NOX reduction in 2007 if all states in the LADCO region fully implemented an IM and OBD

d. Co-benefits of this strategy are significant. PM, HC, and CO are reduced by 48, 48, and 68% respectively. Cetane

e. Co-benefits of this strategy are significant. PM, HC, and CO are reduced by 10, 21, and 11% respectively. 98% of vehicles in this study are pre-1998. Cetane additives may decrease NOX emissions.

f. Opacity reduced 2-6% when switching from regular diesel to B20

g. Opacity reduced 5-11% when switching from regular diesel to B30

h. This test did not demonstrate PM or HC reductions using B20 or CARB diesel.

i. Emission benefits are not readily available for most nonroad applications. However, biodiesel is being used for

j. 1% NOX reduction for line-haul locomotives, 2% for switching.

k. Based on Port of Los Angeles Emissions Inventory. Percentage may differ for LADCO region.

l. Co-benefits include reductions in PM, CO, and greenhouse gases. Low blends of ethanol demonstrate a slight increase in VOC cold-start emissions when compared to regular gasoline.

m. ENVIRON report assumes 15% participation in 2009 and 30% participation of HDDV anti-idling measures by 2012. The report also assumes 25% and 50% of switching and linehaul locomotives respectively.

n. Calculation of percentage NOX control efficiency would require knowledge of the percentage of time a truck would participate in anti-idling programs. It is assumed that 100% of NOX would be reduced during the anti-idling time.

o. Control efficiency was cited from the ENVIRON Phase II report.

p. Control efficiencies were calculated based on the g/bhp-hr engine standard of the upgraded engine vs. the old engine.

q. Also demonstrates 10-30% PM reduction

r. ENVIRON Phase II report analyzes emission reductions and cost-effectiveness of LNC combined with DPF, resulting in PM reduction co-benefits and combined costs results.

s. ENVIRON Phase II report analyzes emission reductions and cost-effectiveness of EGR combined with DPF, resulting in PM, VOC, and CO reduction co-benefits and combined costs results.

t. ENVIRON Phase II report analyzes emission reductions and cost-effectiveness of SCR combined with DOC, resulting in PM, VOC, and CO reduction co-benefits and combined costs results.

u. ENVIRON Phase II report analyzes emission reductions and cost-effectiveness of SCR combined with DPF, resulting in PM, VOC, and CO reduction co-benefits and combined costs results.

v. Candidate measure ID EGU1

w. Candidate measure ID EGU2

x. Candidate measure ID ICI1. *Timing of Implementation* : Assumes full reductions achieved in 2009. *Implementation*

y. Candidate measure ID ICI2. *Timing of Implementation* : Assumes full reductions achieved in 2013 *Implementation Area* :

z. Candidate measure ID ICI3. *Timing of Implementation* : Assumes full reductions achieved in 2009 *Implementation Area* :

aa. Applies to CO, HC (and toxics), PM, and somewhat for NOx, probably for nontailpipe HCs. Fresno Study referenced in Doug Lawson's presentation cited a 53% reduction in NOX, 65% in HC, and 94% in CO.

bb. Baseline and on-the-way measures are listed here as additional information that was provided by the LADCO white papers. We will include discussion on these existing or upcoming measures for all source categories in our final report.

Appendix B-8. Notes on Control Strategies

cc. used only on lean burn, natural gas spark ignited engines
dd. natural gas- and diesel-fired
ee. source 27 states 95% efficiency for rich-burn spark ignited engines
ff. source 27 states 95% efficiency for rich-burn spark ignited engines
gg. source 27 states 90% efficiency for internal combustion sources
hh. AirControlNET provided information on control technologies from multiple pollution sources; the reduction in tons listed under "Efficiency Estimate (%)" is an average of all the sources for a particular technology
ii. high cost
jj. Efficiency calculations are based on estimates of atmospheric losses, assuming a consistent distribution of losses among ammonia and other gases (N_2O and N_2)
kk. Baseline is spreading manure without incorporation
ll. Costly, even with cost-sharing, average price is $1000/cow
mm. Moderate to high cost
nn. Baseline is open ground storage (leaving manure on ground with no method of collection or storage)
oo. Baseline is earthen ground storage (leaving manure on ground with no method of collection or storage)
pp. Baseline is broadcasting manure with no waiting time before incorporation
qq. no particular strategy is described as "best practice" but State offers technical specifications for structures to meet standard, e.g., storage volume, depth, how much stress can be placed on the structure depending on the material
ss. the inhibitor works on ammonium forms of nitrogen; it is recommended to use this technique in the late summer or fall; reference also recommends timings of manure application (specific soil temperatures)
tt. reference broke out nutrient availability among indoor pit, outdoor pit, and farrow-nursery indoor pit storage options; all
uu. reference broke out nutrient availability among duck, chicken, turkey, and poultry manure; all had same nutrient
vv. reference provides efficiency in capturing solids from waste stream
ww. reference provides technical specifications for dimensions and distances from water sources
xx. reference provides material components and technical specifications for transfer mechanism

[continued]

Appendix C
EGU Control Analysis Parameters and Individual EGU and ICI Boiler Facility Analyses

Contents

Tables

C.1 Cost Equations and Control Efficiencies for EGU

Costs for regional EGU control strategies were analyzed using cost equations developed for the Integrated Planning Model (IPM).[1] The IPM model is commonly used to estimate the costs of large-scale pollution control programs. The cost equation parameters are shown in Table C-1. Control efficiencies used in the EGU regional strategy analyses are shown in Table C-2.

C.2 EGU and ICI Boiler Individual Facility Analyses

Eleven electric generating facilities were selected for more in-depth analyses. The analyses of these facilities were designed to ensure that opportunities for cost-effective visibility improvements were not overlooked. None of these facilities are required to completed BART analyses nor are they expected to reduce emissions pursuant to CAIR. Each of these facilities includes multiple boilers, totaling 35 individual boilers that were analyzed. For these plant-specific analyses we estimated costs using the IPM cost equations,[3] and also drew on a number of additional data sources, including a Menu of Options for controlling $PM_{2.5}$ and its precursors by the National Association of Clean Air Agencies (NACAA, formerly STAPPA and ALAPCO)[2] and the Coal Utility Environmental Cost (CUECost) worksheet.[3] For ICIs smaller than 100 MW, an ICI boiler cost estimation methodology developed by EPA was used.[4,5]

Tables C-1 through C-11 present detailed estimates of capital and annualized costs for each individual unit, emissions reductions, and cost effectiveness for each control technology. The control technologies were selected to achieve the either the EGU1 cap or both the EGU1 and EGU2 caps. Table C-12 is the analysis for an ICI boiler at Boise Cascade Corporation.[a] In this case, the control technologies meet both the ICI1 rule and the ICI Workgroup recommendation.

It must be noted that the reported results are estimates. In fact, control cost estimates can vary by at a factor of 2 or more. There are a number of reasons for this range of cost estimates. First, all of the costing approaches rely on default assumptions for flue gas conditions, and for retrofit costs and other contingency costs. These assumptions may differ from model to model. In addition, the cost equations have been developed for different base years, and use different inflation factors to project costs to subsequent years. The CueCost and IPM models also use

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[a]The ICI Workgroup recommendation and the *Candidate Measure ID ICI1* control strategies discussed in section 5.2 are used in this facility analysis. The Workgroup recommendation results in a regional cap for SO_2 emissions of 1.2 lb/mmBtu (a 77% rollback of emissions for either the 3-state or 9-state region). When conducting the facility analysis of an ICI boiler (Boise Cascade Corporation/International Falls in Minnesota) we found only one unit at the facility emitted SO_2. The remaining units all burned natural gas and so had negligible SO_2 emissions. According to Boise's 2005 permit, the SO_2 emissions from Unit 2 amount to .1 lb/mmBtu, well below the regional emissions caps. Therefore, this facility would not be controlled under this rule for SO_2, and further cost analysis for ICI1 was not necessary. Analyses were conducted for ICI1 NO_X, and the Workgroup recommendation for both NO_X and SO_2.

different scaling factors to calculate costs for various boiler sizes. The NACAA report only provides cost effectiveness values for broad boiler size ranges.

C.3 Example CUECOST Individual Facility Input Spreadsheet

CUECost is a set of interrelated Excel spreadsheets that focus on costs for coal-fired power plants. In the CUECost spreadsheets, the user has the ability to change all the parameters to suit the facility under analysis. A sensitivity analysis of CUECost conducted by EPA has shown that the following variables have significant impacts on the cost results (greater than 5%):[6]

- Unit capacity
- Heat rate
- Coal sulfur content
- Coal heating value
- Capacity factor
- Disposal mode

Unit capacities and heat rates for individual EGUs were obtained from the NEEDS database, and capacity factors for 2018 were calculated based on the IPM unit-specific fuel consumption estimates. Fuel sulfur contents were obtained from operating permits, where possible, or calculated from SO_2 emission rates reported in the NEI database. We assumed that the disposal mode for sludge and ash will be landfilling. It must be noted that the results are ball-park figures; default values were used when plant-specific information required by CUECost was not available in the operating permits.

Tables C-17 and C-18 show an example of an individual facility analysis with the CUECost program. Table C-20 shows the inputs for the program, and Table C-21 presents the results. This example is from the JH Campbell facility in Michigan, which has three units (Boilers 1, 2 and 3). Plant-specific information was used in the highlighted rows (the same type of information was available for all other facilities as well). CUECost allows the user to specify the type of coal being used at the facility, either choosing from its coal library or, if the coal is not found in the library, input the coal characteristics for more accurate results. We often exercised the latter option in our analyses. In this example Boiler 3 uses a different coal than Boilers 1 and 2. In cases like this, two separate analyses were conducted (i.e., two separate spreadsheets were used): one for the boilers using coal type A and a second for boilers using coal type B.

References for Appendix C

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Table C-1. IPM Cost Equation Parameters Used for EGU Control Strategy Analyses

Control technology	Fuel and boiler type	Capital cost factors*: Base value ($/kW)	Capital cost factors*: Scale factor	Capital cost factors*: Expon-ent	Fixed operating and maintenance scaling factors*: Base value ($/kW-yr)	Fixed O&M: Scale factor	Fixed O&M: Expon-ent	Variable operating and maintenance cost factors*: Base value (cents/kWh)	Variable O&M: Scale factor	Variable O&M: Expon-ent
SO2 Controls										
Limestone forced oxidation scrubber	<100 MW	511.1	100	0.62	20.75	100	0.47	0.153	na	na
	100-300 MW	251.2	300	0.62	12.01	300	0.39	0.153	na	na
	300-500 MW	190.0	500	0.55	9.83	500	0.35	0.153	na	na
	500-700 MW	155.1	700	0.60	8.74	700	0.37	0.153	na	na
	>700 MW	131.0	1,000	0.47	7.64	1,000	0.37	0.153	na	na
Lime spray dryer scrubber	<100 MW	312.3	100	0.50	14.20	100	0.47	0.153	na	na
	100-300 MW	169.3	300	0.33	8.74	300	0.56	0.153	na	na
	300-500 MW	143.1	500	0.31	6.55	500	0.54	0.153	na	na
	500-700 MW	128.9	700	0.15	5.46	700	0.63	0.153	na	na
	>700 MW	122.3	1,000	0.15	4.37	1,000	0.63	0.153	na	na
NOX Controls										
SCR	Coal	133.8	243	0.27	0.89	243	0.27	0.080	243	0.11
	Oil / gas	38.6	200	0.35	1.19	200	0.35	0.013	na	na
SNCR	Coal, pulverized, term 1**	22.9	200	0.58	0.34	200	0.58	0.118	na	na
	Coal, pulverized, term 2**	26.1	100	0.68	0.40	100	0.68	0.118	na	na
	Coal, cyclone	13.2	300	0.58	0.19	300	0.58	0.223	na	na
	Coal, fluidized bed	22.9	200	0.58	0.35	200	0.58	0.102	na	na
	Oil / gas	13.0	200	0.58	0.20	200	0.58	0.060	na	na
LNB without OFA	Coal, wall-fired	23.1	300	0.36	0.35	300	0.36	0.007	na	na
LNB with OFA	Coal, wall-fired	31.3	300	0.36	0.48	300	0.36	0.010	na	na
LNB with close-coupled OFA	Coal, tangential	12.2	300	0.36	0.02	300	0.36	0.000	na	na
LNB with separated OFA	Coal, tangential	17.0	300	0.36	0.25	300	0.36	0.003	na	na
LNB with close-coupled and separated OFA	Coal, tangential	19.4	300	0.36	0.30	300	0.36	0.003	na	na
Limestone forced oxidation scrubber	<100 MW	511.1	100	0.62	20.75	100	0.47	0.153	na	na
	100-300 MW	251.2	300	0.62	12.01	300	0.39	0.153	na	na
	300-500 MW	190.0	500	0.55	9.83	500	0.35	0.153	na	na
	500-700 MW	155.1	700	0.60	8.74	700	0.37	0.153	na	na
	>700 MW	131.0	1,000	0.47	7.64	1,000	0.37	0.153	na	na
Lime spray dryer scrubber	<100 MW	312.3	100	0.50	14.20	100	0.47	0.153	na	na
	100-300 MW	169.3	300	0.33	8.74	300	0.56	0.153	na	na
	300-500 MW	143.1	500	0.31	6.55	500	0.54	0.153	na	na
	500-700 MW	128.9	700	0.15	5.46	700	0.63	0.153	na	na
	>700 MW	122.3	1,000	0.15	4.37	1,000	0.63	0.153	na	na

* Cost equations take the following form: Cost = (Base value) x (Scale Factor/MW)^(exponent)
where "Base value," "Scale factor," and "exponent" are terms defined in the table, and MW is the capacity of the boiler

**For SNCR applied to pulverized coal, terms 1 and 2 are added together.

Source: Reference 1

Table C-2. Emission Control Efficiencies Used for EGU Control Strategy Analyses

Control technology	Fuel and boiler type	Estiamated control efficiency (%)
SO2 control measures		
Limestone forced oxidation scrubber	Coal /oil	95
Lime spray dryer scrubber	Coal /oil	90
NOX control measures		
SCR	Coal	90
	Oil / gas	80
SNCR	Coal, pulverized or cyclone	35
	Coal, fluidized bed	50
	Oil / gas	50
LNB without OFA	Coal, wall-fired	35
LNB with OFA	Coal, wall-fired	40
LNB with close-coupled OFA	Coal, tangential	40
LNB with separated OFA	Coal, tangential	45
LNB with close-coupled and separated OFA	Coal, tangential	50

Table C-3. Estimated Cost and Cost Effectiveness for EGU1 and EGU2 Control Strategies for the Detroit Edison/St. Clair-Belle River Facility (Michigan)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	St. Clair/ Belle River	1	Coal	153	5,491	LSD	90	CUECost	54,602	6,604	14,783	4,942	2,991	10,628	18,012	4,942	5,216	150-3452
								IPM	44,092	4,023	10,628	4,942	2,151					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	71,543	7,295	18,012	5,216	3,453					
								IPM	69,090	4,938	15,288	5,216	2,931					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	162	6,162	LSD	90	CUECost	59,169	7,156	16,020	5,546	2,888	11,009	19,257	4,942	5,216	150-3289
								IPM	45,379	4,211	11,009	5,546	1,985					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	76,687	7,769	19,257	5,854	3,289					
								IPM	70,608	5,155	15,732	5,854	2,687					
								STAPPA	-	-	-	-	200-5000					
		3	Coal	171	6,132	LSD	90	CUECost	58,567	7,149	15,923	5,519	2,885	11,425	19,263	4,942	5,825	150-3306
								IPM	46,631	4,440	11,425	5,519	2,070					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	76,094	7,864	19,263	5,825	3,307					
								IPM	72,074	5,412	16,209	5,825	2,783					
								STAPPA	-	-	-	-	200-5000					
		4	Coal	158	5,734	LSD	90	CUECost	56,209	6,840	15,260	5,160	2,957	10,774	18,434	4,942	5,447	150-3384
								IPM	44,811	4,061	10,774	5,160	2,088					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	73,110	7,482	18,434	5,447	3,384					
								IPM	69,940	4,992	15,469	5,447	2,840					
								STAPPA	-	-	-	-	200-5000					
		6	Coal	321	11,765	LSD	90	CUECost	75,056	10,823	22,066	10,588	2,084	16,444	25,653	4,942	11,176	150-2295
								IPM	61,545	7,224	16,444	10,588	1,553					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	92,898	11,737	25,653	11,176	2,295					
								IPM	89,995	8,446	21,928	11,176	1,962					
								STAPPA	-	-	-	-	200-5000					
		7	Coal	450	11,765	LSD	90	CUECost	90,888	15,164	28,779	10,588	2,718	21,036	32,737	4,942	11,176	150-2929
								IPM	77,195	9,472	21,036	10,588	1,987					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	111,146	16,088	32,737	11,176	2,929					
								IPM	104,903	11,187	26,902	11,176	2,407					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**1,415**	**47,048**									**77,147**	**133,356**	**42,344**	**44,696**	**1822-2984**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	St. Clair/ Belle River	1	Coal	153	1,071	SCR	90	CUECost	15,493	1,520	3,602	963	3,739	599	6,764	375	963	200-1148
								IPM	24,436	1,143	4,428	963	4,596					
								STAPPA	-	-	-	-	1000-2000					

Table C-3. Estimated Cost and Cost Effectiveness for EGU1 and EGU2 Control Strategies for the Detroit Edison/St. Clair-Belle River Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
						SNCR	35	CUECost	2,219	301	599	375	1,600					
								IPM	3,727	1,420	1,921	375	5,126					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	5,375	120	843	375	2,250					
								IPM	4,741	155	792	375	2,114					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	5,006	6,091	6,764	589	11,488					
								IPM	-	-	-	589	-					
								STAPPA	-	-	-	-	500-2000					
		2	Coal	162	1,693	SCR	90	CUECost	17,433	1,736	4,079	1,524	2,677	744	7,595	593	1,524	200-8156
								IPM	25,477	1,207	4,631	1,524	3,039					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,479	411	744	593	1,255					
								IPM	3,809	1,508	2,020	593	3,409					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	5,579	125	875	593	1,476					
								IPM	-	-	-	593	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	5,339	6,878	7,595	931	8,156					
								IPM	-	-	-	931	-					
								STAPPA	-	-	-	-	500-2000					
		3	Coal	171	1,195	SCR	90	CUECost	16,866	1,651	3,918	1,076	3,641	638	7,505	418	1,076	200-1141
								IPM	26,503	1,291	4,853	1,076	4,510					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,376	319	638	418	1,525					
								IPM	3,888	1,627	2,149	418	5,137					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	5,778	129	906	418	2,166					
								IPM	-	-	-	418	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	5,485	6,767	7,505	657	11,414					
								IPM	-	-	-	657	-					
								STAPPA	-	-	-	-	500-2000					
		4	Coal	158	1,118	SCR	90	CUECost	16,244	1,616	3,799	1,006	3,776	609	7,079	391	1,006	200-1151
								IPM	25,017	1,145	4,507	1,006	4,480					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,276	303	609	391	1,556					
								IPM	3,773	1,422	1,929	391	4,931					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	5,489	123	861	391	2,200					
								IPM	4,840	157	807	391	2,063					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	5,083	6,396	7,079	615	11,514					
								IPM	-	-	-	615	-					
								STAPPA	-	-	-	-	500-2000					

Table C-3. Estimated Cost and Cost Effectiveness for EGU1 and EGU2 Control Strategies for the Detroit Edison/St. Clair-Belle River Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		6	Coal	321	1,766	SCR	90	CUECost	25,234	2,886	6,278	1,589	3,950	846	13,028	618	1,589	200-1341
								IPM	41,972	2,180	7,821	1,589	4,921					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,070	433	846	618	1,369					
								IPM	4,939	2,942	3,606	618	5,834					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	8,701	195	1,364	618	2,207					
								IPM	-	-	-	618	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	7,844	11,974	13,028	971	13,414					
								IPM	-	-	-	971	-					
								STAPPA	-	-	-	-	500-2000					
		7	Coal	450	1,766	SCR	90	CUECost	33,526	4,143	8,648	1,589	5,442	1,214	10,190	618	1,589	200-7980
								IPM	53,710	2,972	10,190	1,589	6,412					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,891	691	1,214	618	1,964					
								IPM	5,619	4,177	4,932	618	7,980					
								STAPPA	-	-	-	-	800-1500					
	Plant Total			**1,415**	**8,609**									**4,649**	**51,639**	**3,013**	**7,748**	**1543-6665**

Table C-4. Consumers Energy Company/JH Campbell Facility (Michigan)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	JH Campbell	1	Coal	260	10,767	LSD	90	CUECost	78,193	11,709	23,423	9,690	2,417	14,483	24,314	9,690	10,229	150-2417
								IPM	57,580	5,858	14,483	9,690	1,495					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	93,492	10,309	24,314	10,229	2,377					
								IPM	84,520	7,077	19,738	10,229	1,930					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	355	12,986	LSD	90	CUECost	83,538	13,935	26,449	11,688	2,263	17,567	27,430	11,688	12,337	150-2263
								IPM	65,844	7,704	17,567	11,688	1,503					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	99,523	12,521	27,430	12,337	2,223					
								IPM	94,201	9,060	23,171	12,337	1,878					
								STAPPA	-	-	-	-	200-5000					
		3	Coal	820	30,020	LSD	90	CUECost	112,653	24,860	41,735	27,018	1,545	32,371	47,039	27,018	28,519	150-1649
								IPM	119,585	14,457	32,371	27,018	1,198					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	156,806	23,550	47,039	28,519	1,649					
								IPM	136,680	17,580	38,055	28,519	1,334					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**1435**	**53773**									**64,421**	**98,783**	**48,396**	**51,085**	**1331-1934**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	JH Campbell	1	Coal	260	3,153	SCR	78	CUECost	29,285	3,146	7,082	2,459	2,880	1,116	12,797	1,104	2,459	200-7379
								IPM	35,987	1,719	6,556	2,459	2,666					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,316	671	1,116	1,104	1,012					
								IPM	4,559	2,250	2,862	1,104	2,594					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	7,589	170	1,190	1,104	1,078					
								IPM	-	-	-	1,104	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	6,885	11,872	12,797	1,734	7,379					
								IPM	-	-	-	1,734	-					
								STAPPA	-	-	-	-	500-2000					

Table C-4. Consumers Energy Company/JH Campbell Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		2	Coal	355	7,359	SCR	88	CUECost	33,388	4,005	8,492	6,476	1,311	1,457	15,574	2,576	6,476	200-3848
								IPM	45,173	2,336	8,407	6,476	1,298					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,946	1,424	1,954	2,576	759					
								IPM	5,133	3,182	3,872	2,576	1,503					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	9,292	208	1,457	2,576	566					
								IPM	-	-	-	2,576	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	8,375	14,448	15,574	4,047	3,848					
								IPM	-	-	-	4,047	-					
								STAPPA	-	-	-	-	500-2000					
		3	Coal	820	11,799	SCR	70	CUECost	64,401	8,825	17,481	8,259	2,117	2,511	17,481	4,130	8,259	200-2117
								IPM	90,557	4,830	17,000	8,259	2,058					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	6,647	2,231	3,124	4,130	757					
								IPM	7,069	6,937	7,887	4,130	1,910					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	16,012	359	2,511	4,130	608					
								IPM	-	-	-	4,130	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	17,069	6,921	9,215	6,489	1,420					
								IPM	-	-	-	6,489	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**1435**	**22311**									**5,084**	**45,851**	**7,809**	**17,194**	**651-2667**

Table C-5. Wisconsin Electric/Presque Isle Facility (Michigan)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	WI Electric/Presque Isle	5	Coal	88	3,431	LSD	90	CUECost	45,698	4,761	11,607	3,088	3,759	6,536	14,697	3,088	3,259	150-4509
								IPM	27,815	2,369	6,536	3,088	2,117					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	62,139	5,389	14,697	3,259	4,509					
								IPM	46,657	2,935	9,924	3,259	3,045					
								STAPPA	-	-	-	-	200-5000					
		6	Coal	88	3,416	LSD	90	CUECost	45,635	4,750	11,586	3,075	3,768	6,536	14,680	3,075	3,245	150-4523
								IPM	27,815	2,369	6,536	3,075	2,126					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	62,076	5,381	14,680	3,245	4,523					
								IPM	46,657	2,935	9,924	3,245	3,058					
								STAPPA	-	-	-	-	200-5000					
		7	Coal	88	2,046	LSD	90	CUECost	47,226	5,026	12,100	1,842	6,570	6,536	15,113	1,842	1,944	150-7773
								IPM	27,815	2,369	6,536	1,842	3,549					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	63,665	5,576	15,113	1,944	7,773					
								IPM	46,657	2,935	9,924	1,944	5,104					
								STAPPA	-	-	-	-	200-5000					
		8	Coal	88	1,965	LSD	90	CUECost	46,584	4,914	11,893	1,768	6,726	6,536	14,938	1,768	1,866	150-8004
								IPM	27,815	2,369	6,536	1,768	3,697					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	63,027	5,497	14,938	1,866	8,004					
								IPM	46,657	2,935	9,924	1,866	5,317					
								STAPPA	-	-	-	-	200-5000					
		9	Coal	88	1,967	LSD	90	CUECost	46,605	4,918	11,899	1,770	6,721	6,536	14,944	1,770	1,869	150-7997
								IPM	27,815	2,369	6,536	1,770	3,692					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	63,047	5,499	14,944	1,869	7,997					
								IPM	46,657	2,935	9,924	1,869	5,310					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**440**	**12,825**									**32,679**	**74,371**	**11,543**	**12,184**	**2831-6104**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	WI Electric/Presque Isle	5	Coal	88	1,012	SCR	90	CUECost	12,663	988	2,690	910	2,954	427	4,066	354	910	200-7308
								IPM	16,319	685	2,878	910	3,161					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,916	288	546	354	1,542					
								IPM	3,023	799	1,205	354	3,404					
								STAPPA	-	-	-	-	800-1500					

Table C-5. Wisconsin Electric/Presque Isle Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
						LNB	35	CUECost	2,720	61	427	354	1,205					
								IPM	-	-	-	354	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,534	4,066	556	7,308					
								IPM	-	-	-	556	-					
								STAPPA	-	-	-	-	500-2000					
		6	Coal	88	1,049	SCR	90	CUECost	12,630	984	2,681	944	2,839	427	4,051	367	944	200-7020
								IPM	16,319	685	2,878	944	3,047					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,913	288	545	367	1,483					
								IPM	3,023	799	1,205	367	3,282					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,720	61	427	367	1,161					
								IPM	-	-	-	367	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,519	4,051	577	7,020					
								IPM	-	-	-	577	-					
								STAPPA	-	-	-	-	500-2000					
		7	Coal	88	1,218	SCR	90	CUECost	13,467	1,082	2,892	1,096	2,640	427	4,430	426	1,096	200-6615
								IPM	16,319	685	2,878	1,096	2,626					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,982	308	574	426	1,348					
								IPM	3,023	799	1,205	426	2,828					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,720	61	427	426	1,001					
								IPM	-	-	-	426	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,897	4,430	670	6,615					
								IPM	-	-	-	670	-					
								STAPPA	-	-	-	-	500-2000					
		8	Coal	88	1,063	SCR	90	CUECost	13,130	1,042	2,807	957	2,934	427	4,276	372	957	200-7314
								IPM	16,319	108	2,302	957	2,406					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,954	300	562	372	1,512					
								IPM	3,023	799	1,205	372	3,240					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,720	61	427	372	1,146					
								IPM	-	-	-	372	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,744	4,276	585	7,314					
								IPM	-	-	-	585	-					
								STAPPA	-	-	-	-	500-2000					

Table C-5. Wisconsin Electric/Presque Isle Facility (Michigan)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		9	Coal	88	1,120	SCR	90	CUECost	13,141	1,044	2,690	1,008	2,668	427	4,066	392	1,008	200-6084
								IPM	16,319	685	2,878	1,008	2,854					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,955	300	546	392	1,392					
								IPM	3,023	799	1,205	392	3,074					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,720	61	427	392	1,088					
								IPM	-	-	-	392	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,962	3,749	4,066	616	6,084					
								IPM	-	-	-	616	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**440**	**5,462**									**2,133**	**20,890**	**1,912**	**4,916**	**1116-4250**

Table C-6. Minnesota Power/Clay Boswell Facility (Minnesota)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Clay Boswell	1	Coal	69	2,587	LSD	90	CUECost	45,601	5,271	12,102	2,328	5,198	5,660	14,108	2,328	2,458	150-5741
								IPM	24,610	1,974	5,660	2,328	2,431					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	59,232	5,235	14,108	2,458	5,741					
								IPM	42,536	2,469	8,841	2,458	3,598					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	69	2,572	LSD	90	CUECost	46,112	5,266	12,174	2,315	5,259	5,625	14,169	2,315	2,443	150-5799
								IPM	24,610	1,938	5,625	2,315	2,430					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	59,739	5,220	14,169	2,443	5,799					
								IPM	42,536	2,434	8,806	2,443	3,604					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**138**	**5159**									**11,285**	**28,276**	**4,643**	**4,901**	**2431-5770**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Clay Boswell	1	Coal	69	693	SCR	90	CUECost	10,693	761	2,198	624	3,524	472	3,157	243	624	500-8281
								IPM	13,664	550	2,387	624	3,825					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,754	237	472	243	1,947					
								IPM	2,758	627	997	243	4,111					
								STAPPA	-	-	-	-	800-1500					
						NGR	55	CUECost	3,635	2,669	3,157	381	8,281					
								IPM	-	-	-	381	-					
								STAPPA	-	-	-	-	500-2000					
		2	Coal	69	689	SCR	90	CUECost	10,937	781	2,251	620	3,628	474	3,142	241	620	500-8289
								IPM	13,664	531	2,367	620	3,817					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,773	236	474	241	1,965					
								IPM	2,758	602	973	241	4,032					
								STAPPA	-	-	-	-	800-1500					
						NGR	55	CUECost	3,635	2,654	3,142	379	8,289					
								IPM	-	-	-	379	-					
								STAPPA	-	-	-	-	500-2000					
		4	Coal	426	4,859	SCR	90	CUECost	36,447	3,805	8,703	4,373	1,990	1,408	23,558	1,701	4,373	500-8815
								IPM	51,611	3,525	10,461	4,373	2,392					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,919	882	1,408	1,701	828					
								IPM	5,503	5,033	5,773	1,701	3,394					
								STAPPA	-	-	-	-	800-1500					
						NGR	55	CUECost	9,854	22,234	23,558	2,673	8,815					
								IPM	-	-	-	2,673	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**564**	**6242**									**2,355**	**29,857**	**2,185**	**5,617**	**1078-5315**

Table C-7. Minnesota Power/Syl Laskin Facility (Minnesota)*

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Syl Laskin	1	Coal	55	951	LSD	90	CUECost	44,526	4,856	11,526	856	13,460	4,955	11,526	856	904	150-13460
								IPM	21,945	1,668	4,955	856	5,786					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	37,652	4,253	9,894	904	10,945					
								IPM	39,005	2,106	7,949	904	8,794					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	55	950	LSD	90	CUECost	58,190	4,856	13,573	855	15,873	4,698	13,573	855	903	150-15873
								IPM	21,945	1,662	4,949	855	5,788					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	58,192	4,852	13,569	903	15,033					
								IPM	39,005	2,100	7,943	903	8,800					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**110**	**1902**									**9,653**	**25,099**	**1,711**	**1,807**	**5640-13894**

* This facility is installing NOx controls so NOx control costs were not evaluated

Table C-8. Northshore Mining Company/Silver Bay Facility (Minnesota)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Northshore/Silver Bay	1	Coal	85	851	LSD	90	CUECost	43,277,712	3,894	10,377	766	13,549	3,465	12,918	766	808	150-16041
								IPM	17,737	808	3,465	766	4,524					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	58,235	4,195	12,918	808	15,979					
								IPM	33,215	1,156	6,132	808	7,585					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**85**	**851**									**3,465**	**12,918**	**766**	**808**	**922-16041**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Northshore/Silver Bay	1	Coal	85	1122	SCR	90	CUECost	11,870	849	2,627	1,010	2,602	322	2,627	16	40	200-2602
								IPM	8,498	56	1,199	1,010	1,187					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,758	205	468	393	1,192					
								IPM	2,160	32	322	393	821					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	3,668	82	632	393	1,609					
								IPM	2,546	39	381	393	971					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,912	844	1,430	617	2,317					
								IPM	-	-	-	617	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**85**	**1122**									**322**	**2,627**	**16**	**40**	**821-2322**

Table C-9. Virginia Public Utilities Commission Facility (Minnesota)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Virginia PUC	7	Coal	10	584	LSD	90	CUECost	30,787	1,616	6,228	525	11,859	6,228	8,933	525	554	150-16116
								IPM	-	-	-	525	-					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	44,821	2,219	8,933	554	16,116					
								IPM	-	-	-	554	-					
								STAPPA	-	-	-	-	200-5000					
		9	Coal	10	584	LSD	90	CUECost	30,787	1,616	6,228	525	11,859	6,228	8,933	525	554	150-16116
								IPM	-	-	-	525	-					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	44,821	2,219	8,933	554	16,116					
								IPM	-	-	-	554	-					
								STAPPA	-	-	-	-	200-5000					
		10	Coal	10	12,606	LSD	90	CUECost	30,787	1,616	6,228	11,346	549	6,228	8,933	11,346	11,976	150-922
								IPM	-	-	-	11,346	-					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	44,821	2,219	8,933	11,976	-					
								IPM	-	-	-	11,976	-					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**30**	**13,773**									**18,684**	**26,800**	**12,396**	**13,085**	**1507-2048**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MN	Virginia PUC	7	Coal	10	125	SCR	90	CUECost	4,188	180	743	113	6,589	143	743	44	113	200-9011
								IPM	3,254	68	505	113	4,481					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,259	115	284	44	6,477					
								IPM	1,322	67	245	44	5,584					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	913	20	143	44	3,264					
								IPM	-	-	-	44	-					
								STAPPA	-	-	-		200-1000					
						NGR	55	CUECost	2,270	316	621	69	9,011					
								IPM	-	-	-	69	-					
								STAPPA	-	-	-	-	500-2000					
		9	Coal	10	125	SCR	90	CUECost	4,188	180	743	113	6,589	143	743	44	113	200-9011
								IPM	3,254	68	505	113	4,481					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,259	115	284	44	6,477					
								IPM	1,322	67	245	44	5,584					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	913	20	143	44	3,264					
								IPM	-	-	-	44	-					
								STAPPA	-	-	-		200-1000					
						NGR	55	CUECost	2,270	316	621	69	9,011					
								IPM	-	-	-	69	-					
								STAPPA	-	-	-	-	500-2000					

Table C-9. Virginia Public Utilities Commission Facility (Minnesota)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		10	Coal	10	0	SCR	90	CUECost	4,188	180	743	0	-	108	743	0	0	-
								IPM	-	-	-	0	-					
								STAPPA	-	-	-	-	-					
						SNCR	35	CUECost	1,259	115	284	0	-					
								IPM	720	11	108	0	-					
								STAPPA	-	-	-	-	-					
						LNB	35	CUECost	913	20	143	0	-					
								IPM	-	-	-	0	-					
								STAPPA	-	-	-	-	-					
						NGR	55	CUECost	2,270	316	621	0	-					
								IPM	-	-	-	0	-					
								STAPPA	-	-	-	-	-					
	Plant Total			**30**	**251**									**394**	**2,229**	**88**	**226**	**4495-9884**

Table C-10. Dairyland Power Coop/Alma Facility (Wisconsin)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Dairylan	1	Coal	18	1,384	LSD	90	CUECost	33,226	2,297	7,274	1,245	5,841	2,748	9,953	1,245	1,315	150-7571
								IPM	12,606	859	2,748	1,245	2,206					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	47,057	2,904	9,953	1,315	7,571					
								IPM	25,663	1,101	4,945	1,315	3,762					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	18	1,165	LSD	90	CUECost	33,226	2,213	7,190	1,048	6,858	2,701	9,874	1,048	1,107	150-8922
								IPM	12,606	813	2,701	1,048	2,576					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	47,057	2,825	9,874	1,107	8,922					
								IPM	25,663	1,054	4,899	1,107	4,426					
								STAPPA	-	-	-	-	200-5000					
		3	Coal	22	1,396	LSD	90	CUECost	34,312	2,416	7,556	1,256	6,016	2,986	10,284	1,256	1,326	150-7757
								IPM	13,805	918	2,986	1,256	2,378					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	48,384	3,036	10,284	1,326	7,757					
								IPM	27,487	1,184	5,302	1,326	3,999					
								STAPPA	-	-	-	-	200-5000					
		4	Coal	57	2,415	LSD	90	CUECost	42,672	4,086	10,478	2,174	4,820	5,090	13,325	2,174	2,295	150-5807
								IPM	22,357	1,741	5,090	2,174	2,341					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	57,570	4,701	13,325	2,295	5,807					
								IPM	39,561	2,188	8,114	2,295	3,536					
								STAPPA	-	-	-	-	200-5000					
		5	Coal	77	3,514	LSD	90	CUECost	43,802	4,382	10,944	3,163	3,460	6,175	14,097	3,163	3,338	150-4223
								IPM	26,064	2,271	6,175	3,163	1,953					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	60,464	5,039	14,097	3,338	4,223					
								IPM	44,421	2,798	9,453	3,338	2,832					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**192**	**9,874**									**19,701**	**57,533**	**8,886**	**9,380**	**2217-6134**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reductior	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Dairylan	1	Coal	18	316	SCR	90	CUECost	5,047	244	922	285	3,238	152	1,336	111	285	200-7682
								IPM	5,178	221	917	285	3,223					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,301	146	321	111	2,900					
								IPM	1,675	231	456	111	4,119					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	970	22	152	111	1,373					
								IPM	1,214	31	194	111	1,753					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	2,548	994	1,336	174	7,682					
								IPM	-	-	-	174	-					
								STAPPA	-	-	-	-	500-2000					

Table C-10. Dairyland Power Coop/Alma Facility (Wisconsin)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		2	Coal	18	266	SCR	90	CUECost	5,047	242	920	240	3,840	152	1,226	93	240	200-8370
								IPM	5,178	192	888	240	3,705					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,300	139	314	93	3,369					
								IPM	1,675	198	423	93	4,544					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	970	22	152	93	1,631					
								IPM	1,214	29	192	93	2,061					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	2,548	883	1,226	146	8,370					
								IPM	-	-	-	146	-					
								STAPPA	-	-	-	-	500-2000					
		3	Coal	22	319	SCR	90	CUECost	5,662	290	1,051	287	3,662	173	1,411	112	287	200-8043
								IPM	5,908	224	1,018	287	3,547					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,349	148	330	112	2,953					
								IPM	1,792	234	475	112	4,257					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	1,105	25	173	112	1,552					
								IPM	1,363	33	216	112	1,939					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	2,661	1,053	1,411	175	8,043					
								IPM	-	-	-	175	-					
								STAPPA	-	-	-	-	500-2000					
		4	Coal	57	773	SCR	90	CUECost	10,041	697	2,046	696	2,942	322	2,973	271	696	200-6993
								IPM	11,888	479	2,076	696	2,985					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,700	227	456	271	1,684					
								IPM	2,567	537	882	271	3,259					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,051	46	322	271	1,189					
								IPM	-	-	-	271	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,418	2,513	2,973	425	6,993					
								IPM	-	-	-	425	-					
								STAPPA	-	-	-	-	500-2000					
		5	Coal	77	1,124	SCR	90	CUECost	11,907	922	2,522	1,012	2,492	391	4,119	394	1,012	200-6660
								IPM	14,851	676	2,672	1,012	2,640					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,856	288	538	394	1,366					
								IPM	2,880	787	1,174	394	2,984					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	2,494	56	391	394	994					
								IPM	-	-	-	394	-					
								STAPPA	-	-	-		200-1000					
						NGR	55	CUECost	3,775	3,611	4,119	618	6,660					
								IPM	-	-	-	618	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**192**	**2,799**									**1,190**	**11,065**	**980**	**2,519**	**1556-4392**

Table C-11. Xcel Energy/Bay Front Facility (Wisconsin)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Xcel Energ	1	Coal	22	1,890	LSD	90	CUECost	37,322	2,701	8,291	1,701	4,876	2,953	11,074	1,701	1,795	150-6169
								IPM	13,843	879	2,953	1,701	1,736					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	51,934	3,294	11,074	1,795	6,169					
								IPM	27,544	1,146	5,272	1,795	2,937					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	22	1,890	LSD	90	CUECost	36,222	2,666	8,092	1,701	4,758	2,992	10,865	1,701	1,795	150-6053
								IPM	13,843	919	2,992	1,701	1,760					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	50,684	3,272	10,865	1,795	6,053					
								IPM	27,544	1,186	5,312	1,795	2,959					
								STAPPA	-	-	-	-	200-5000					
		5	Coal	30	1,478	LSD	90	CUECost	36,662	2,553	8,045	1,330	6,047	3,457	10,888	1,330	1,404	150-7753
								IPM	16,182	1,033	3,457	1,330	2,598					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	51,173	3,222	10,888	1,404	7,753					
								IPM	30,991	1,348	5,991	1,404	4,266					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**74**	**5,257**									**9,402**	**32,826**	**4,731**	**4,994**	**1987-6573**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Xcel Energ	1	Coal	22	509	SCR	90	CUECost	7,479	443	1,448	458	3,163	173	1,777	178	458	200-6350
								IPM	5,932	199	996	458	2,175					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,518	192	396	178	2,223					
								IPM	1,796	206	447	178	2,510					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	1,105	25	173	178	973					
								IPM	-	-	-	178	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	2,661	1,419	1,777	280	6,350					
								IPM	-	-	-	280	-					
								STAPPA	-	-	-	-	500-2000					
		2	Coal	22	447	SCR	90	CUECost	6,757	384	1,292	402	3,213	173	1,777	156	402	200-7227
								IPM	5,932	223	1,021	402	2,537					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,437	168	361	156	2,310					
								IPM	1,796	233	475	156	3,036					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	1,105	25	173	156	1,107					
								IPM	-	-	-	156	-					
								STAPPA	-	-	-	-	200-1000					

Table C-11. Xcel Energy/Bay Front Facility (Wisconsin)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
						NGR	55	CUECost	2,661	1,419	1,777	246	7,227					
								IPM	-	-	-	246	500-2000					
								STAPPA	-	-	-	-	1,285					
		5	Coal	30	517	SCR	90	CUECost	7,216	411	1,381	466	2,966	212	1,505	181	466	200-5287
								IPM	7,439	229	1,229	466	2,640					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,515	188	392	181	2,165					
								IPM	1,582	419	631	181	3,486					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	1,352	30	212	181	1,170					
								IPM	-	-	-	181	-					
								STAPPA	-	-	-	181	200-1000					
						NGR	55	CUECost	2,862	1,120	1,505	285	5,287					
								IPM	-	-	-	285	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**74**	**1,473**									**558**	**5,058**	**516**	**1,326**	**1083-3815**

Table C-12. Alliant Energy-Wisconsin Power/Edgewater Facility (Wisconsin)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Alliant Ene	3	Coal	75	1,864	LSD	90	CUECost	47,351	5,328	12,421	1,677	7,406	5,955	14,711	1,677	1,770	150-8310
								IPM	25,747	2,098	5,955	1,677	3,550					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	60,864	5,593	14,711	1,770	8,310					
								IPM	44,012	2,618	9,211	1,770	5,203					
								STAPPA	-	-	-	-	200-5000					
		4	Coal	334	8,277	LSD	90	CUECost	86,380	17,366	30,306	7,449	4,068	17,153	31,414	7,449	7,863	150-4068
								IPM	63,174	7,690	17,153	7,449	2,303					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	98,542	16,653	31,414	7,863	3,995					
								IPM	91,600	8,963	22,684	7,863	2,885					
								STAPPA	-	-	-	-	200-5000					
		5	Coal	422	10,672	LSD	90	CUECost	87,931	13,842	27,014	9,605	2,813	19,892	30,888	9,605	10,138	150-3047
								IPM	73,892	8,823	19,892	9,605	2,071					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	107,638	14,764	30,888	10,138	3,047					
								IPM	101,846	10,432	25,689	10,138	2,534					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**831**	**20,812**									**43,000**	**77,013**	**18,731**	**19,771**	**2296-3895**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Alliant Ene	3	Coal	75	865	SCR	90	CUECost	11,459	844	2,384	779	3,061	497	3,501	303	779	200-7355
								IPM	14,589	590	2,550	779	3,275					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	1,815	253	497	303	1,641					
								IPM	2,337	1,233	1,547	303	5,109					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	3,382	76	530	303	1,751					
								IPM	-	-	-	303	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	3,743	2,998	3,501	476	7,355					
								IPM	-	-	-	476	-					
								STAPPA	-	-	-	-	500-2000					
		4	Coal	334	3,285	SCR	90	CUECost	28,738	3,183	7,045	2,957	2,383	1,232	14,090	1,150	2,957	200-7797
								IPM	43,182	2,370	8,174	2,957	2,764					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,322	785	1,232	1,150	1,071					
								IPM	4,382	6,012	6,601	1,150	5,741					
								STAPPA	-	-	-	-	800-1500					

Table C-12. Alliant Energy-Wisconsin Power/Edgewater Facility (Wisconsin)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
						LNB	35	CUECost	8,929	200	1,400	1,150	1,218					
								IPM	-	-	-	1,150	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	8,058	13,007	14,090	1,807	7,797					
								IPM	-	-	-	1,807	-					
								STAPPA	-	-	-	-	500-2000					
		5	Coal	422	1,971	SCR	90	CUECost	33,963	3,698	8,263	1,774	4,659	863	16,789	690	1,774	200-15491
								IPM	51,214	2,727	9,610	1,774	5,419					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	3,533	388	863	690	1,251					
								IPM	5,481	3,792	4,529	690	6,566					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	7,536	169	1,182	690	1,713					
								IPM	-	-	-	690	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	9,791	15,474	16,789	1,084	15,491					
								IPM	-	-	-	1,084	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**831**	**6,121**									**2,592**	**34,380**	**2,142**	**5,509**	**1210-6240**

Table C-13. Alliant Energy-Wisconsin Power/Nelson Dewey Facility (Wisconsin)

Costs of SO2 Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Alliant Energy/N	1	Coal	108	4,206	LSD	90	CUECost	54,250	8,018	16,145	3,786	4,265	8,642	17,324	3,786	3,996	150-4335
								IPM	36,950	3,107	8,642	3,786	2,283					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	66,535	7,357	17,324	3,996	4,335					
								IPM	60,457	3,864	12,921	3,996	3,233					
								STAPPA	-	-	-	-	200-5000					
		2	Coal	111	4,127	LSD	90	CUECost	54,432	7,949	16,103	3,714	4,336	8,738	17,320	3,714	3,920	150-4418
								IPM	37,434	3,131	8,738	3,714	2,353					
								STAPPA	-	-	-	-	150-4000					
						LSFO	95	CUECost	66,701	7,328	17,320	3,920	4,418					
								IPM	61,054	3,898	13,044	3,920	3,327					
								STAPPA	-	-	-	-	200-5000					
	Plant Total			**219**	**8,333**									**17,381**	**17,320**	**7,500**	**7,916**	**2318-2199**

Costs of NOx Controls for EGUs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
WI	Alliant Energy/N	1	Coal	108	1,262	SCR	90	CUECost	14,058	1,159	3,049	1,136	2,684	487	4,904	442	1,136	200-7066
								IPM	18,912	849	3,391	1,136	2,986					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,033	326	599	442	1,357					
								IPM	2,716	1,871	2,236	442	5,063					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	3,108	70	487	442	1,103					
								IPM	-	-	-	442	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	4,294	4,327	4,904	694	7,066					
								IPM	-	-	-	694	-					
								STAPPA	-	-	-	-	500-2000					
		2	Coal	111	1,238	SCR	90	CUECost	14,135	1,161	3,061	1,114	2,747	496	4,830	433	1,114	200-7093
								IPM	19,272	850	3,440	1,114	3,087					
								STAPPA	-	-	-	-	1000-2000					
						SNCR	35	CUECost	2,039	322	596	433	1,375					
								IPM	2,746	1,871	2,240	433	5,171					
								STAPPA	-	-	-	-	800-1500					
						LNB	35	CUECost	3,163	71	496	433	1,145					
								IPM	-	-	-	433	-					
								STAPPA	-	-	-	-	200-1000					
						NGR	55	CUECost	4,343	4,246	4,830	681	7,093					
								IPM	-	-	-	681	-					
								STAPPA	-	-	-	-	500-2000					
	Plant Total			**219**	**2,500**									**983**	**9,734**	**875**	**2,250**	**1124-4326**

Table C-14. Boise Cascade Corporation (Minnesota)

Costs of SO2 Controls for ICIs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost-Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	Boise Cascade Corp.	2	Gas	38	48	LSD	90	CUECost	51,688	3,169	10,912	43	254,398	3,966	10,912	43	45	92472-242492
								IPM	18,130	1,373	4,089	43	95,333					
								Khan (2003)*	17,294	1,376	3,966	43	92,472					
								STAPPA	-	-	-	-	1,011					
						LSFO	95	CUECost	32,346	2,199	7,044	45	155,586					
								IPM	33,769	1,730	6,789	45	149,938					
								Khan (2003)*	17,294	1,376	3,966	45	87,605					
								STAPPA	-	-	-	-	1,011					
	Plant Total			**38**	**48**									**3,966**	**10,912**	**43**	**45**	**92472-242492**

Costs of NOx Controls for ICIs

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost-Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
MI	Boise Cascade Corp.	1	Gas	38	104	SCR	80	CUECost	7,076	398	1,349	84	16,146	120	2,769	37	81	424-43450
								IPM	2,768	129	501	84	5,990					
								Khan (2003)*	2,485	238	572	84	6,847					
								STAPPA	-	-	-	-	1,354					
						SNCR	50	CUECost	1,366	116	299	52	5,733					
								IPM	1,353	219	401	52	7,678					
								Khan (2003)*	1,307	299	475	52	9,094					
								STAPPA	-	-	-	-	2,193					
						LNB	35	CUECost	2,174	49	341	37	9,322					
								IPM	1,023	2	139	37	3,805					
								Khan (2003)*	792	61	167	37	4,569					
								STAPPA	-	-	-		424					
						NGR	61	CUECost	3,041	2,360	2,769	64	43,450					
								IPM	-	-	-	64	-					
								Khan (2003)*	446	61	120	64	1,891					
								STAPPA	-	-	-	-	-					

Table C-14. Boise Cascade Corporation (Minnesota)

State	Facility	Unit	Fuel	Capacity (MW)	Baseline Emissions (tons)	Control Technology	% Reduction	Cost Model	Total Capital Investment [$M2005]	Total O&M Cost [$M2005]	Total Annualized Cost [$M2005]	Emission Reduction (tons)	Cost-Effectiveness [$2005/ton]	Lowest Annualized Cost ($M2005)	Highest Annualized Cost ($M2005)	Lowest Emissions Reduced (tons)	Highest Emissions Reduced (tons)	Cost Effectiveness ($2005/ton)
		2	Gas	38	331	SCR	90	CUECost	7,331	421	1,406	265	5,307	169	1,406	116	291	424-27803
								IPM	2,749	127	497	265	1,875					
								Khan (2003)*	2,511	241	579	265	2,185					
								STAPPA	-	-	-	-	1,354					
						SNCR	35	CUECost	1,448	159	354	166	2,137					
								IPM	1,347	217	398	166	2,401					
								Khan (2003)*	1,321	304	482	166	2,908					
								STAPPA	-	-	-	-	2,193					
						LNB	35	CUECost	2,159	48	339	37	9,258					
								IPM	2	1,016	1,017	37	27,803					
								Khan (2003)*	801	61	169	37	4,623					
								STAPPA	-	-	-		424					
		3	Gas	35	25	SCR	90	CUECost	6,669	361	1,257	20	62,895	117	1,652	9	19	797-108392
								IPM	2,624	97	450	20	22,500					
								Khan (2003)*	2,413	230	554	20	27,716					
								STAPPA	-	-	-	-	2,330					
						SNCR	35	CUECost	1,322	101	279	12	22,303					
								IPM	1,307	96	271	12	21,728					
								Khan (2003)*	1,269	287	458	12	36,626					
								STAPPA	-	-	-	-	3,116					
						LNB	35	CUECost	2,061	46	323	9	36,942					
								IPM	1,550	28	236	9	27,018					
								Khan (2003)*	769	58	162	9	18,501					
								STAPPA					797					
						NGR	61	CUECost	2,975	1,252	1,652	15	108,392					
								IPM	-	-	-	15	-					
								Khan (2003)*	433	58	117	15	7,648					
								STAPPA	-	-	-	-	-					
	Plant Total			**76**	**436**									**406**	**5,827**	**161**	**392**	**2519-14849**

* "Total O&M Costs" for Khan (2003) also includes annual costs (e.g., annual catalyst replacement, fuel costs). For all other models "Total O&M Costs" do not contain any annual costs.

Table C-15. CUECost Example - Input Data for Analysis (JH Campbell, Michigan)

APC Technology Choices

Description	Units	Suggested Range	Default Values	Boiler 1	Boiler 2	Boiler 3	Boiler 3	Boiler 3
FGD Process (1 = LSFO, 2 = LSD)	Integer	1 or 2	1	1	2	1	2	1
Particulate Control (1 = Fabric Filter, 2 = ESP)	Integer	1 or 2	1	1	1	1	1	1
NOx Control (1 = SCR, 2 = SNCR, 3 = LNBs, 4 = NGR)	Integer	1 - 4	1	1	2	1	2	4

INPUTS

General Plant Technical Inputs

Description	Units	Range	Default Values	Boiler 1	Boiler 2	Boiler 3	Boiler 3	Boiler 3
Location - State	Abbrev.	All States	PA	MI	MI	MI	MI	MI
MW Equivalent of Flue Gas to Control System	MW	100-2000	500	260	355	820	820	820
Net Plant Heat Rate (w/o APC)	Btu/kWhr		10,500	13,269	11,243	11,814	11,814	11,814
Plant Capacity Factor	%	40-90%	65%	77%	81%	77%	77%	77%
Percent Excess Air in Boiler	%		120%	120%	120%	120%	120%	120%
Air Heater Inleakage	%		12%	12%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F		300	300	300	300	300	300
Inlet Air Temperature	°F		80	80	80	80	80	80
Ambient Absolute Pressure	In. of Hg		29.4	29.4	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O		-12	-12	-12	-12	-12	-12
Moisture in Air	lb/lb dry air		0.013	0.013	0.013	0.013	0.013	0.013
Ash Split:								
Fly Ash	%		80%	80%	80%	80%	80%	80%
Bottom Ash	%		20%	20%	20%	20%	20%	20%
Seismic Zone	Integer	1-5	1	1	1	1	1	1
Retrofit Factor (1.0 = new, 1.3 = medium, 1.6 = difficult)	Integer	1.0-3.0	1.3	1.3	1.3	1.3	1.3	1.3
Select Coal	Integer	1-8	1	8	8	8	8	8
Is Selected Coal a Powder River Basin Coal?	Yes / No	See Column K	Yes	No	No	No	No	No

Coals Available in Library

Coal 1, Wyoming PRB: 8,227 Btu, 0.37% S, 5.32% ash
Coal 2, Armstrong, PA: 13,100 Btu, 2.6% S, 9.1% ash
Coal 3, Jefferson, OH: 11,922 Btu, 3.43% S, 13% ash
Coal 4, Logan, WV: 12,058 Btu, 0.89% S, 16.6% ash
Coal 5, No. 6 Illinois: 10,100 Btu, 4% S, 16% ash
Coal 6, Rosebud, MT: 8,789 Btu, 0.56% S, 8.15% ash
Coal 7, Lignite, ND: 7,500 Btu, 0.94% S, 5.9% ash
Coal 8, "User Specified": 12,062 Btu, 1% S, 16.6% ash

Economic Inputs

Description	Units	Range	Default Values	Boiler 1	Boiler 2	Boiler 3	Boiler 3	Boiler 3
Cost Basis -Year Dollars	Year		1998	2005	2005	2005	2005	2005
Sevice Life (levelization period)	Years		30	15	15	15	15	15
Inflation Rate	%		3.00%	3.99%	3.99%	3.99%	3.99%	3.99%
After Tax Discount Rate (current $'s)	%		9.20%	9.20%	9.20%	9.20%	9.20%	9.20%
AFDC Rate (current $'s)	%		10.80%	10.80%	10.80%	10.80%	10.80%	10.80%
First-year Carrying Charge (current $'s)	%		22.30%	14.98%	14.98%	14.98%	14.98%	14.98%
Levelized Carrying Charge (current $'s)	%		16.90%	16.90%	16.90%	16.90%	16.90%	16.90%
First-year Carrying Charge (constant $'s)	%		15.70%	15.70%	15.70%	15.70%	15.70%	15.70%
Levelized Carrying Charge (constant $'s)	%		11.70%	11.70%	11.70%	11.70%	11.70%	11.70%
Sales Tax	%		6%	6%	6%	6%	6%	6%
Escalation Rates:								
Consumables (O&M)	%		3%	3%	3%	3%	3%	3%
Capital Costs:								
Is Chem. Eng. Cost Index available?	Yes / No		Yes	Yes	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer		388	468.3	468.3	468.3	468.3	468.3
If "No" input escalation rate.	%		3%	3%	3%	3%	3%	3%
Construction Labor Rate	$/hr		$35	$32	$32	$32	$32	$32
Prime Contractor's Markup	%		3%	3%	3%	3%	3%	3%
Operating Labor Rate	$/hr		$30	$31	$31	$31	$31	$31
Power Cost	Mills/kWh		25	68.3	68.3	68.3	68.3	68.3
Steam Cost	$/1000 lbs		3.5	7.44	7.44	7.44	7.44	7.44

Limestone Forced Oxidation (LSFO) Inputs

Description	Units	Range	Default Values	Boiler 1	Boiler 2	Boiler 3	Boiler 3	Boiler 3
SO2 Removal Required	%	90-98%	95%	95%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	95-160	125	125	125	125	125	125
Design Scrubber with Dibasic Acid Addition? (1 = yes, 2 = no)	Integer	1 or 2	2	2	2	2	2	2
Adiabatic Saturation Temperature	°F	100-170	127	127	127	127	127	127

Table C-15. CUECost Example - Input Data for Analysis (JH Campbell, Michigan)

Reagent Feed Ratio	Factor	1.0-2.0	1.05	1.05	1.05	1.05	1.05	1.05
(Mole CaCO3 / Mole SO2 removed)								
Scrubber Slurry Solids Concentration	Wt. %		15%	15%	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	1,2,3	1	1	1	1	1	1
(1 = stacking, 2 = landfill, 3 = wallboard)								
Number of Absorbers	Integer	1-6	1	1	1	1	1	1
(Max. Capacity = 700 MW per absorber)								
Absorber Material	Integer	1 or 2	1	1	1	1	1	1
(1 = alloy, 2 = RLCS)								
Absorber Pressure Drop	in. H2O		6	6	6	6	6	6
Reheat Required ?	Integer	1 or 2	1	1	1	1	1	1
(1 = yes, 2 = no)								
Amount of Reheat	°F	0-50	25	25	25	25	25	25
Reagent Bulk Storage	Days		60	60	60	60	60	60
Reagent Cost (delivered)	$/ton		$15	$15	$15	$15	$15	$15
Landfill Disposal Cost	$/ton		$30	$30	$30	$30	$30	$30
Stacking Disposal Cost	$/ton		$6	$6	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton		$2	$2	$2	$2	$2	$2
Maintenance Factors by Area (% of Installed Cost)								
Reagent Feed	%		5%	5%	5%	5%	5%	5%
SO2 Removal	%		5%	5%	5%	5%	5%	5%
Flue Gas Handling	%		5%	5%	5%	5%	5%	5%
Waste / Byproduct	%		5%	5%	5%	5%	5%	5%
Support Equipment	%		5%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)								
Reagent Feed	%		20%	20%	20%	20%	20%	20%
SO2 Removal	%		20%	20%	20%	20%	20%	20%
Flue Gas Handling	%		20%	20%	20%	20%	20%	20%
Waste / Byproduct	%		20%	20%	20%	20%	20%	20%
Support Equipment	%		20%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)								
Reagent Feed	%		10%	10%	10%	10%	10%	10%
SO2 Removal	%		10%	10%	10%	10%	10%	10%
Flue Gas Handling	%		10%	10%	10%	10%	10%	10%
Waste / Byproduct	%		10%	10%	10%	10%	10%	10%
Support Equipment	%		10%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)								
Reagent Feed	%		10%	10%	10%	10%	10%	10%
SO2 Removal	%		10%	10%	10%	10%	10%	10%
Flue Gas Handling	%		10%	10%	10%	10%	10%	10%
Waste / Byproduct	%		10%	10%	10%	10%	10%	10%
Support Equipment	%		10%	10%	10%	10%	10%	10%

Lime Spray Dryer (LSD) Inputs

SO2 Removal Required	%	90-95%	90%	90%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	100-170	127	127	127	127	127	127
Flue Gas Approach to Saturation	°F	10.-50	20	20	20	20	20	20
Spray Dryer Outlet Temperature	°F	110-220	147	147	147	147	147	147
Reagent Feed Ratio	Factor	Calc. Based on %S	0.90	1.04	1.04	1.04	1.04	1.04
(Mole CaO / Mole Inlet SO2)								
Recycle Rate	Factor	Calculated	30	7.5	7.5	7.5	7.5	7.5
(lb recycle / lb lime feed)								
Recycle Slurry Solids Concentration	Wt. %	10-50	35%	35%	35%	35%	35%	35%
Number of Absorbers	Integer	1-7	2	2	2	2	2	2
(Max. Capacity = 300 MW per spray dryer)								
Absorber Material	Integer	1 or 2	1	1	1	1	1	1
(1 = alloy, 2 = RLCS)								
Spray Dryer Pressure Drop	in. H2O		5	5	5	5	5	5
Reagent Bulk Storage	Days		60	60	60	60	60	60
Reagent Cost (delivered)	$/ton		$65	$65	$65	$65	$65	$65
Dry Waste Disposal Cost	$/ton		$30	$30	$30	$30	$30	$30
Maintenance Factors by Area (% of Installed Cost)								
Reagent Feed	%		5%	5%	5%	5%	5%	5%
SO2 Removal	%		5%	5%	5%	5%	5%	5%
Flue Gas Handling	%		5%	5%	5%	5%	5%	5%
Waste / Byproduct	%		5%	5%	5%	5%	5%	5%
Support Equipment	%		5%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)								
Reagent Feed	%		20%	20%	20%	20%	20%	20%
SO2 Removal	%		20%	20%	20%	20%	20%	20%
Flue Gas Handling	%		20%	20%	20%	20%	20%	20%
Waste / Byproduct	%		20%	20%	20%	20%	20%	20%
Support Equipment	%		20%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)								
Reagent Feed	%		10%	10%	10%	10%	10%	10%
SO2 Removal	%		10%	10%	10%	10%	10%	10%
Flue Gas Handling	%		10%	10%	10%	10%	10%	10%

Table C-15. CUECost Example - Input Data for Analysis (JH Campbell, Michigan)

Waste / Byproduct	%		10%	10%	10%	10%	10%	10%
Support Equipment	%		10%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)								
Reagent Feed	%		10%	10%	10%	10%	10%	10%
SO2 Removal	%		10%	10%	10%	10%	10%	10%
Flue Gas Handling	%		10%	10%	10%	10%	10%	10%
Waste / Byproduct	%		10%	10%	10%	10%	10%	10%
Support Equipment	%		10%	10%	10%	10%	10%	10%
NOx Control Inputs								
Selective Catalytic Reduction (SCR) Inputs								
NH3/NOX Stoichiometric Ratio	NH3/NOX	0.7-1.0	0.9	D	D	D	D	D
NOX Reduction Efficiency	Fraction	0.60-0.90	0.70	0.9	0.9	0.9	0.9	0.9
Inlet NOx	lbs/MMBtu		0.9	0.27	0.5225	0.3624	0.3624	0.3624
Space Velocity (Calculated if zero)	1/hr		0	D	D	D	D	D
Overall Catalyst Life	years	2-5	3	D	D	D	D	D
Ammonia Cost	$/ton		206	D	D	D	D	D
Catalyst Cost	$/ft3		356	D	D	D	D	D
Solid Waste Disposal Cost	$/ton		11.48	D	D	D	D	D
Maintenance (% of installed cost)	%		1.5%	D	D	D	D	D
Contingency (% of installed cost)	%		20%	D	D	D	D	D
General Facilities (% of installed cost)	%		5%	D	D	D	D	D
Engineering Fees (% of installed cost)	%		10%	D	D	D	D	D
Number of Reactors	integer		2	D	D	D	D	D
Number of Air Preheaters	integer		1	D	D	D	D	D
Selective NonCatalytic Reduction (SNCR) Inputs								
Reagent	integer	1:Urea 2:Ammonia	1	D	D	D	D	D
Number of Injector Levels	integer		3	D	D	D	D	D
Number of Injectors	integer		18	D	D	D	D	D
Number of Lance Levels	integer		0	D	D	D	D	D
Number of Lances	integer		0	D	D	D	D	D
Steam or Air Injection for Ammonia	integer	1: Steam, 2: Air	1	D	D	D	D	D
NOX Reduction Efficiency	fraction	0.30-0.70	0.50	0.35	0.35	0.35	0.35	0.35
Inlet NOx	lbs/MMBtu		0.9	0.27	0.5225	0.3624	0.3624	0.3624
NH3/NOX Stoichiometric Ratio	NH3/NOX	0.8-2.0	1.2	D	D	D	D	D
Urea/NOX Stoichiometric Ratio	Urea/NOX	0.8-2.0	1.2	D	D	D	D	D
Urea Cost	$/ton		225	D	D	D	D	D
Ammonia Cost	$/ton		206	D	D	D	D	D
Water Cost	$/1,000 gal		0.4	D	D	D	D	D
Maintenance (% of installed cost)	%		1.5%	D	D	D	D	D
Contingency (% of installed cost)	%		20%	D	D	D	D	D
General Facilities (% of installed cost)	%		5%	D	D	D	D	D
Engineering Fees (% of installed cost)	%		10%	D	D	D	D	D
Low NOX Burner Technology Inputs								
NOX Reduction Efficiency	fraction	0.15-0.60	0.35	D	D	D	D	D
Boiler Type	T:T-fired, W:Wall		T	D	D	D	D	D
Retrofit Difficulty	L:Low, A:Average, H:High		A	D	D	D	D	D
Maintenance Labor (% of installed cost)	%		0.8%	D	D	D	D	D
Maintenance Materials (% of installed cost)	%		1.2%	D	D	D	D	D
Natural Gas Reburning Inputs								
NOX Reduction Efficiency	fraction	0.55-0.65	0.61	D	D	D	D	D
Gas Reburn Fraction	fraction	0.08 - 0.20	0.15	D	D	D	D	D
Waste Disposal Cost	$/ton		11.48	D	D	D	D	D
Natural Gas Cost	$/MMBtu		2.31	5	5	5	5	5
Maintenance (% of installed cost)	%		1.5%	D	D	D	D	D
Contingency (% of installed cost)	%		20%	D	D	D	D	D
General Facilities (% of installed cost)	%		2%	D	D	D	D	D
Engineering Fees (% of installed cost)	%		10%	D	D	D	D	D

Table C-16. CUECost Example - Results Output of Analysis (JH Campbell facility, Michigan)

Description	Units	Boiler 1	Boiler 2
SUMMARY OF COSTS			
APC Technologies			
NOx Control		SCR	SNCR
Particulate Control		PJFF	PJFF
SO2 Control		LSFO	LSD
NOx Control Costs →		SCR	SNCR
Total Capital Requirement (TCR)	$	$29,284,539	$3,945,946
	$/kW	$112.6	$11.1
First Year Costs			
Fixed O&M	$	$407,517	$117,261
	$/kW-Yr	1.57	0.33
	Mills/kWH	0.23	0.05
	$/ton NOx removed	$109	$66
Variable O&M	$	$2,738,948	$1,306,727
	$/kW-Yr	10.53	3.68
	Mills/kWH	1.56	0.52
	$/ton NOx removed	$733	$739
Fixed Charges	$	$4,386,824	$591,103
	$/kW-Yr	16.87	1.67
	Mills/kWH	2.50	0.23
	$/ton NOx removed	$1,174	$334
TOTAL	$	$7,533,289	$2,015,091
	$/kW-Yr	28.97	5.68
	Mills/kWH	4.30	0.80
	$/ton NOx removed	$2,016	$1,140
Levelized Current Dollars			
Fixed O&M	$/kW-Yr	1.91	0.40
	Mills/kWH	0.28	0.06
	$/ton NOx removed	$133	$81
Variable O&M	$/kW-Yr	12.83	4.48
	Mills/kWH	1.90	0.63
	$/ton NOx removed	$893	$900
Fixed Charges	$/kW-Yr	19.03	1.88
	Mills/kWH	2.82	0.26
	$/ton NOx removed	$1,325	$377
TOTAL	$/kW-Yr	33.77	6.76
	Mills/kWH	5.01	0.95
	$/ton NOx removed	$2,350	$1,358
Levelized Constant Dollars			
Fixed O&M	$/kW-Yr	1.57	0.33
	Mills/kWH	0.23	0.05
	$/ton NOx removed	$109	$66
Variable O&M	$/kW-Yr	10.53	3.68
	Mills/kWH	1.56	0.52
	$/ton NOx removed	$733	$739
Fixed Charges	$/kW-Yr	13.18	1.30
	Mills/kWH	1.86	0.17
	$/ton NOx removed	$875	$249
TOTAL	$/kW-Yr	25.28	5.31
	Mills/kWH	3.66	0.74
	$/ton NOx removed	$1,717	$1,054
SO2 Control Costs →		LSFO	LSD
Total Capital Requirement (TCR)	$	$93,491,840	$83,537,509
	$/kW	$360	$235
First Year Costs			
Fixed O&M	$	$5,268,554	$4,777,549
	$/kW-Yr	20.26	13.46
	Mills/kWH	3.00	1.90
	$/ton SO2 removed	$287.8	$226.3
Variable O&M	$	$5,040,781	$9,157,340
	$/kW-Yr	19.39	25.80
	Mills/kWH	2.87	3.64
	$/ton SO2 removed	$275.3	$433.8
Fixed Charges	$	$14,005,078	$12,513,919
	$/kW-Yr	53.87	35.25
	Mills/kWH	7.99	4.97
	$/ton SO2 removed	$764.9	$592.8
TOTAL	$	$24,314,412	$26,448,808
	$/kW-Yr	93.52	74.50
	Mills/kWH	13.86	10.50
	$/ton SO2 removed	$1,328	$1,253
Levelized Current Dollars			
Fixed O&M	$/kW-Yr	24.67	16.39
	Mills/kWH	3.66	2.31
	$/ton SO2 removed	$350.4	$275.6
Variable O&M	$/kW-Yr	23.61	31.41

Table C-16. CUECost Example - Results Output of Analysis (JH Campbell facility, Michigan)

	Mills/kWH	3.50	4.43
	$/ton SO2 removed	$335.2	$528.2
Fixed Charges	$/kW-Yr	60.77	39.77
	Mills/kWH	9.01	5.60
	$/ton SO2 removed	$863.0	$668.8
TOTAL	$/kW-Yr	109.05	87.56
	Mills/kWH	16.17	12.34
	$/ton SO2 removed	$1,548.6	$1,472.6
Levelized Constant Dollars			
Fixed O&M	$/kW-Yr	20.26	13.46
	Mills/kWH	3.00	1.90
	$/ton SO2 removed	$287.8	$226.3
Variable O&M	$/kW-Yr	19.39	25.80
	Mills/kWH	2.87	3.64
	$/ton SO2 removed	$275.3	$433.8
Fixed Charges	$/kW-Yr	42.07	27.53
	Mills/kWH	5.95	3.70
	$/ton SO2 removed	$570.0	$441.8
TOTAL	$/kW-Yr	81.72	66.79
	Mills/kWH	11.83	9.23
	$/ton SO2 removed	$1,133.1	$1,101.9

Due to the detailed nature of CUECost, the resulting cost effectiveness figures will not match exactly to what is reported in Section 5.1.6. However, the differences are insignificant and well within the +/- 30% range.