Source Category: Electric Generating Units

INTRODUCTION

The purpose of this document is to provide a forum for public review and comment on the evaluation of candidate control measures that may be considered by the States in the Midwest Regional Planning Organization (MRPO) to develop strategies for ozone, PM2.5, and regional haze State Implementation Plans (SIPs). Additional emission reductions beyond those due to mandatory controls required by the Clean Air Act may be necessary to meet SIP requirements and to demonstrate attainment. This document provides background information on the mandatory control programs and on possible additional control measures.

The candidate control measures identified in this document represent an initial set of possible measures. The MRPO States have not yet determined which measures will be necessary to meet the requirements of the Clean Air Act. As such, the inclusion of a particular measure here should not be interpreted as a commitment or decision by any State to adopt that measure. Other measures will be examined in the near future. Subsequent versions of this document will likely be prepared for evaluation of additional potential control measures.

The evaluation of candidate control measures is presented in a series of "Interim White Papers." Each paper includes a title, summary table, description of the source category, brief regulatory history, discussion of candidate control measures, expected emission reductions, cost effectiveness and basis, timing for implementation, rule development issues, other issues, and a list of supporting references. Tables 1a and 1b summarize this information for the electric generating unit (EGU) source category.

SOURCE CATEGORY DESCRIPTION

Boilers at electric generating units (EGUs) produce steam used to drive turbine generators for electricity production. The fuel used to produce steam is primarily a function of the availability and price of fuels. There is significant nuclear and oil-fired capacity in the Eastern U.S., heavy coal use in the Midwestern and Southeastern states, heavy gas use in the coastal South and on the West Coast, and a large percentage of hydroelectric capacity in the Northwest. Although there are many natural gas-fired or gas/oil fired units in the Midwest, it is important to note that coal-fired units constitute the greatest power output and a very high percentage of SO2 and NOx emissions. In Illinois, for example, coal-fired boilers account for about 51 percent of the non-nuclear generating capacity, 93 percent of the total heat input, 99.8 percent of total SO2 emissions from EGUs, and 98.2 percent of total NOx emissions from EGUs.

Emissions from fossil-fuel combustion at electric utilities depend on several factors, including:

- **Fuel type and quality**. Coal is the primary fossil fuel used by EGUs in the Midwest. Coal is broadly classified into one of four types (anthracite, bituminous, subbituminous, or lignite) based on differences in heating values and amounts of fixed carbon, volatile matter, ash, sulfur, and moisture. Coal mined in the Midwest and Appalachia produce coal ranging from 2 to 4 percent sulfur. Western coal is low in sulfur since it contains less than 1 percent sulfur.
- **Boiler type**. The boiler design plays a role in the uncontrolled emission rate and the applicability of various control strategies. There are four main types of coal boilers – wall-fired, tangentially-fired, cyclone-fired, and stoker-fired.

TABLE 1a – SO2 CONTROL MEASURE SUMMARY FOR EGUs

Control Measure Summary	**SO2 Emissions (tons/year) in 5-state MRPO Region**	
2002 Existing measures (MRPO average SO2 is 1.16 lbs/mmBtu): NSPS; PSD/NSR; State RACT Rules; Title IV SO2 Program	2002 Base:	2,798,884
2009 On-the-Way measures: CAIR (IPM estimates 36% reduction in 2009 emissions from 2002 levels due to early reductions)	Reduction: 2009 Remaining:	-1,003,922 1,794,962
Candidate measure ID EGU1: 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) *Emission Reductions*: 62% reduction from 2002 levels in 2009, 83% reduction from 2002 levels in 2013 *Control Cost*: $800/ton to $1,500/ton *Timing of Implementation*: Assumes full reductions achieved in 2013 *Implementation Area*: 5-State MRPO region	2009 Reduction: 2009 Remaining: 2013 Reduction: 2013 Remaining:	-1,748,171 1,050,713 -2,333,059 465,825
Candidate measure ID EGU2: 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) *Emission Reductions*: 75% reduction from 2002 levels in 2009, 89% reduction from 2002 levels in 2013 *Control Cost*: $800/ton to $3,000/ton *Timing of Implementation*: Assumes full reductions achieved in 2013 *Implementation Area*: 5-State MRPO region	2009 Reduction: 2009 Remaining: 2013 Reduction: 2013 Remaining:	-2,098,139 700,745 -2,488,334 310,550

TABLE 1b – NOx CONTROL MEASURE SUMMARY FOR EGUs

Control Measure Summary	**Annual NOx Emissions (tons/year) in MRPO Region**	
2002 Existing measures (MRPO average NOx is 0.43 lbs/mmBtu): NSPS; PSD/NSR; State RACT Rules; Title IV NOx Requirements	2002 Base:	1,047,484
2009 On-the-Way: CAIR (IPM estimates 57% reduction from 2002 levels)	Reduction: 2009 Remaining:	-597,854 449,630
Candidate measure ID EGU1: 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) *Emission Reductions*: 58% reduction from 2002 levels in 2009 70% reduction from 2002 levels in 2013 *Control Cost*: $700/ton to $1,600/ton *Timing of Implementation*: Assumes full reductions achieved in 2013 *Implementation Area*: 5-State MRPO region	2009 Reduction: 2009 Remaining: 2013 Reduction: 2013 Remaining:	-609,687 437,797 -736,934 310,550
Candidate measure ID EGU2: 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) *Emission Reductions*: 67% reduction from 2002 levels in 2009 79% reduction from 2002 levels in 2013 *Control Cost*: $700/ton to $2,100/ton *Timing of Implementation*: Assumes full reductions achieved in 2013 *Implementation Area*: 5-State MRPO region	2009 Reduction: 2009 Remaining: 2013 Reduction: 2013 Remaining:	-697,246 350,238 -830,099 217,385

Control Measure Summary	**Ozone Season NOx Emissions (tons/season) in MRPO Region**	
2002 Existing measures (MRPO average NOx is 0.43 lbs/mmBtu): NSPS; PSD/NSR; State RACT Rules; Title IV NOx Requirements	2002 Base:	439,374
2009 On-the-Way: CAIR (IPM estimates 57% reduction from 2002 levels)	Reduction: 2009 Remaining:	-249,049 190,325
Candidate measure ID EGU1: 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) *Emission Reductions*: 57% reduction from 2002 levels in 2009 69% reduction from 2002 levels in 2013 *Control Cost*: $700/ton to $1,600/ton *Timing of Implementation*: Assumes full reductions achieved in 2013 *Implementation Area*: 5-State MRPO region	2009 Reduction: 2009 Remaining: 2013 Reduction: 2013 Remaining:	-249,765 189,609 -304,124 135,250
Candidate measure ID EGU2: 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) *Emission Reductions*: 65% reduction from 2002 levels in 2009 78% reduction from 2002 levels in 2013 *Control Cost*: $700/ton to $2,100/ton *Timing of Implementation*: Assumes full reductions achieved in 2013 *Implementation Area*: 5-State MRPO region	2009 Reduction: 2009 Remaining: 2013 Reduction: 2013 Remaining:	-287,687 151,687 -344,699 94,675

- **Boiler size**. The electric-generating capacity of boilers ranges from approximately 15 to 1300 MW. Given a typical efficiency of about 33 percent, this corresponds to a heat input range of 150 to 13,400 MMBtu/hr.
- **Boiler age**. New boilers tend to be more efficient than older ones. Many boilers over 40 years old still in service, and account for about 30 percent of the coal-fired generating capacity in the MRPO states. .
- **Load**. Depending on utility needs, boilers may be operated somewhat differently. Baseload units are run continuously at a constant, high fraction of maximum rated load. Cycling units are run at a load that varies with demand (e.g., at maximum rated load during the day and low load at night). Peaking units run only during periods of high demand, which in some cases may be limited to the few hottest days of the summer. Newer, large coal-fired units are used primarily as base-load resources, producing electricity around the clock. Older, smaller, and lower-efficiency coal-fire units sometimes are run in a cycling mode during higher peak periods and tend to exhibit lower average capacity utilization factors.
- **Type of control technologies employed**. Most EGUs already employ some level of control technology to meet existing regulatory requirements. In addition, some facilities have switched coal supply regions in order to utilize lower sulfur content coal to meet regulatory requirements.

In 2002, coal combustion at EGUs accounted for about 75% of the total SO2 emissions from all source categories in the MRPO region in 2002, and 28% of the total NOx emissions.

REGULATORY HISTORY

<u>On-the-Books Regulation</u>

Power plant emissions are currently governed by multiple state and federal regulations under the Titles I and IV of the Clean Air Act. Each of these regulatory programs is discussed in the following paragraphs.

Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements includes Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on both the locale's degree of nonattainment with ambient air standards and the local political will for imposing tough air pollution standards. Some 1-hour ozone nonattainment areas, such as those surrounding Lake Michigan, received waivers from the required installation of NOx RACT based on the assessment of relative local ozone improvement versus potential detrimental air quality impact.

Title I also imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. The NSPS applies to coal-fired units that were constructed or modified after 1971. In 1998, EPA revised the NSPS to reflect improvements in control methods for the reduction of NOx emissions.

In addition, Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency (known as New Source Review, or NSR). NSR prescribes control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in nonattainment areas. The control strategies that constitute BACT and LAER evolve over time and are reviewed on a case-by-case basis in state permitting proceedings. For new sources in nonattainment areas, any NOx waiver in effect also applied to NOx offsets and the LAER (vs. BACT) technology requirement.

Title IV of the CAA addresses acid rain by focusing solely on power plant emissions of SO2 and NOx. Emissions of SO2 are capped at 10 million tons per year below 1980 levels. The cap is being attained by reductions achieved in two phases. Phase I began in 1995 and affected 263 units at 110 mostly coal-fired plants located in 21 eastern and Midwestern states. Phase II, which began in 2000, tightened the annual emission limits on the Phase I units and also set restrictions on smaller plants fired by coal, oil, and gas, encompassing over 2,000 units in all. An SO2 allowance trading program has been established at the federal level to provide flexibility to affected sources.

The Acid Rain Program also reduces NOx emissions, again in two phases, with boiler design-specific emission limits. The program began in 1995 with a second phase beginning in 2000. Unlike the SO2 program, there is no cap on emissions or allowance trading. Rather, sources are required to meet certain rates of NOx emissions. Many coal-fired utility boilers installed low NOx burner technologies to meet the new emission standards. However, because there is no cap on Acid Rain Program NOx emissions, NOx emissions may increase in the future as demand for electricity continues to grow.

The 1990 Clean Air Act Amendments also established the Ozone Transport Commission to mitigate interstate transport of pollution in the Northeast. In September 1994, eleven states and the District of Columbia signed a Memorandum of Understanding (MOU) committing to reduce NOx emissions throughout the region. In 1995, the OTC states required existing sources to meet Reasonably Available Control Technology (RACT) limits, and in 1999 through 2002, most of the OTC states achieved deep NOx reductions through an ozone season cap and trade program for NOx called the OTC NOx Budget Program. The OTC states that participated in this trading program included Connecticut, Delaware, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and the District of Columbia.

Separate from the activity in the OTC, EPA and the Environmental Council of the States formed the Ozone Transport Assessment Group (OTAG) in 1995. This workgroup brought together interested states and other stakeholders, including industry and environmental groups. Its primary objective was to assess the ozone transport problem and develop a strategy for reducing ozone pollution throughout the eastern half of the U.S. Based in part on the findings of OTAG, EPA proposed the NOx SIP call in 1997 and finalized it in 1998. The final version of the rule called for NOx emission reductions in twenty-two states (including Ohio, Indiana, Illinois, and the southern half of Michigan, but not Wisconsin) that contributed to 1-hour ozone nonattainment in other states. The rule required affected states to amend their SIPs and limit NOx emissions. EPA set an ozone season NOx budget for each affected state, essentially a cap on emissions from May 1 to September 30 in the state. The first control period was scheduled for the 2004 ozone season. The NOx SIP call did not mandate which sources must reduce emissions but, rather, required states to meet an overall cap (or budget) and gave them flexibility to develop control strategies to meet the cap. The NOx Budget Program was developed to help states meet their NOx SIP call required reductions. States with areas that had obtained NOx waivers for particular facility RACT installations still had to meet their NOx budgets and those NOx reductions associated with the SIP budgets could be counted toward progress requirements of the 1-hour ozone SIPs.

In 1997, while EPA was in the process of developing the NOx SIP Call, eight Northeastern States submitted petitions under section 126 of the CAA asking EPA to address specified power plants in specified states (primarily in the Ohio Valley and other parts of the Midwest. The Section 126 Rule overlaps considerably with the NOx SIP Call. The initiative addressed the 1-hour ozone petition to the degree necessary, tis impact was included in final 1-hour SIPs.

Also in the late 1990s, the EPA initiated an enforcement/compliance effort on certain plants that it found had violated NSR requirements associated with general facility upgrades. The enforcement initiative lead to a series of consent decrees for upgrading the emission control systems on several major power plants. The commitments in the consent decrees are captured for appropriate milestone years in the MRPO's emission projections.

This long-history of EGU regulation by various CAA programs has resulted in a variety of unit level emission limits resulting from SIP, NSPS, NSR, or Acid Rain NOx requirements. Overlaid on these unit-level requirements are system-wide allowances of the NOx SIP call and the Acid Rain SO2 program.

On May 12, 2005, EPA published the Clean Air Interstate Rule (CAIR) to reduce emissions of SO2 and NOx in the eastern states, including Illinois, Indiana, Michigan, Ohio, and Wisconsin. The rule requires states to significantly reduce and cap emission of SO2 and NOx from the power sector. The rule was developed to reduce upwind precursor emissions that will assist downwind areas in meeting the PM2.5 and 8-hour ozone NAAQS. States can meet the emission reduction requirements by either (1) joining an EPA-managed cap-and-trade program for power plants or (2) achieving reductions through other emission control measures. The final CAIR rule set annual emission caps for 2009/2010 and 2015 for the affected region. The final rule also included ozone season emission caps for NOx. Most states (including the five MRPO states) are subject to both the annual SO2/NOx caps and the ozone season NOx cap. A few states are subject only to the annual SO2/NOx caps, while others only the ozone season NOx cap.

The CAIR partitioned the cap levels into state emission budgets that the states may use for granting allowances for SO2 and NOx. The budgets for the affected areas are shown in the following table. It should be noted, however, that projected actual emissions for SO2 are higher than the caps due to the use of previously banked acid rain program allowances retired at discounted valuation. (Table 2, shown later in this document, provides a complete comparison of current 2002 emission levels, projected actual emissions based on IPM modeling, and the final CAIR budgets).

CAIR Affected Region Emission Caps and Expected Emissions (million tons)

Pollutant	2009/2010 Emission Cap	2009/2010 IPM Emissions	2015 Emission Cap	2015 IPM Emissions
Annual SO2 (2010)	3.6	5.1	2.5	4.0
Annual NOx(2009)	1.5	1.5	1.3	1.3
Seasonal NOx (2009)	0.58	0.56	0.48	0.47

On May 18, 2005, EPA promulgated the federal Clean Air Mercury Rule (CAMR). This rule establishes mercury control requirements for new and existing coal-fired electric utility boilers. The rule sets a declining cap on mercury emissions in two distinct phases, 2010 and 2018, for each state. The first phase cap will reduce emissions from 48 tons to 38 tons by taking advantage of "co-benefit" reductions – that is, mercury reductions achieved by reducing SO2 and NOx emissions under CAIR. In the second phase, due in 2018, coal-fired power plants will be subject to a second cap, which will reduce emissions to 15 tons upon full implementation. A national trading program has been developed as an option for states to achieve their mercury emission caps. New emission sources (those that commence construction after January 30, 2004) must meet a standard of performance (pounds of mercury per megawatt-hour), and any mercury emissions from these new sources must also be accommodated under the state mercury cap.

Over the past few years, several states have begun to develop environmental statutes, regulations, permits or other programs that would reduce emissions of multiple pollutants from power plants. The states cite several reasons for going beyond the current regional reductions, including the following reasons: (1) concern over state and local impacts of emissions (including formation of fine particulates); (2) desire to address annual emissions of NOx in addition to seasonal emissions; (3) desire to reduce impacts of NOx beyond ozone formation; (4) the need for additional action to address the impacts of acid rain; (5) desire to reduce known impacts of CO2 and mercury; (6) opportunity to align environmental policy with electric industry restructuring; and (7) opportunity to foster cost-effective compliance strategies through multi-pollutant regulatory programs. In general, these State rules require significant actual emissions reductions from coal-fired power plants in the state, which differs from federal rules, which allow utilities to buy pollution credits from other states instead of cutting air pollution from power plants in state.

CANDIDATE CONTROL MEASURES

Air pollution reduction and control technologies for coal-fired power plants have advanced substantially over the past 25 years. In addition, advances in power generation technologies, renewable energy, and energy efficiency have the potential to further reduce emissions from power plants. We have grouped candidate control strategies into four broad categories, which are broadly described in the following paragraphs:

- **Emission Control Technologies.** Control techniques for criteria pollutants from coal combustion may be classified into three broad categories: fuel treatment/substitution, combustion modification, and post-combustion control. Fuel treatment primarily reduces SO_2 and includes coal cleaning using physical, chemical, or biological processes. Fuel substitution involves burning a cleaner fuel or renewable fuel. Combustion modification includes any physical or operational change in the furnace or boiler and is applied primarily for NO_x control purposes. Post-combustion control employs a device after the combustion of the fuel and is applied to control emissions of SO_2 , and NO_x from coal combustion.
- **Improved Fossil-Fuel Power Generation Technologies.** Most coal-fired power plants operate at an efficiency of roughly 33 percent, and many older plants are less efficient than that. Efficiency can be increased somewhat (10-15%) by modifying the method of combustion at a coal plant. Efficiency can also be boosted significantly (50-60 percent) by utilizing excess heat produced during combustion. Replacing existing coal-fired generation with more efficient technologies is occurring across the country to replace old utility boilers that are at the end of their service life, but this requires major changes in plant equipment and lag time to achieve emission reductions. Improved power generation technologies, such as combined heat and power and gas-fired combined cycle, can improve efficiency as well as reduce SO2 and NOx relative to existing coal generation.
- **Demand Reduction and Energy Efficiency Programs.** These measures are designed to affect the amount of retail electricity consumption. There are many policy options available to promote energy efficiency, including efficiency standards, efficiency programs, pricing incentives, tax incentives, and initiatives that provide customers with information, technical services, energy audits, and financial incentives to help them adopt energy efficiency measures. System benefit surcharges are collected on electricity sales and used to fund energy efficiency projects. Energy

efficiency programs can be designed and run by either the utilities or an independent energy efficiency agency. Public utility commissions have developed rate designs to create an incentive for energy conservation.

- **Clean Power Programs.** Energy sources that are considered to clean and renewable include wind, solar thermal, solar photovoltaic, geothermal, and fuel cells that use renewably derived hydrogen. The are several program options to bring about adoption of these measures. System benefit surcharges are collected on electricity sales and used to fund clean power projects. A renewable portfolio standard is a requirement on retail electricity suppliers to sell clean energy as a certain percentage of their total sales. A variety of states and localities have developed requirements to use renewable resources in government buildings.

The focus of this White Paper is on the first category mentioned above - emission control technologies. The timing and magnitude of reductions from the other three strategies – improved generation technologies, demand reduction/energy efficiency, and clean power – are not likely to achieve the large emissions reductions needed to achieve attainment in the next 3-6 years. However, these other three approaches should be considered as part of a longer-term solution.

As mentioned above, there are a wide variety of proven control technologies for reducing NOx and SO2 emissions from coal-fired utility boilers. Control technologies proven to be effective in the removal of SO2 and NOx, and widely used are summarized in Attachments 1 and 2. The type or types of SO2 and NOx control appropriate for any individual EGU is dependent upon the type of boiler, type of fuel, and the types and staging of other air pollution control devices. However, cost-effective emissions reduction technologies for SO2 and NOx are available and are effective in reducing emissions from the gas stream of utility boilers.

The regulatory approach for EGUs is to reduce NOx and SO2 is through a cap-and-trade program. CAIR establishes a cap-and-trade system for SO2 and NOx based on EPA's Acid Rain Program. EPA already allocated emission "allowances" for SO2 to sources subject to the Acid Rain Program. These allowances will be used in the CAIR model SO2 trading program. For the model NOx trading programs, EPA will provide emission "allowances" for NOx to each state, according to the state budget. The states will allocate those allowances to sources (or other entities), which can trade them. As a result, sources are able to choose from many compliance alternatives, including: installing pollution control equipment; switching fuels; or buying excess allowances from other sources that have reduced their emissions.

State and local agencies have expressed concern about the timing and stringency of the proposed CAIR requirements. For example, STAPPA/ALAPCO suggested that CAIR should include more expeditious deadlines and stringent caps. In 2002, STAPPA and ALAPCO adopted principles in support of a national multi-pollutant strategy for power plants (*Principles for a Multi-Pollutant Strategy for Power Plants*, May 7, 2002). These principles constitute, in the associations' view, a viable approach upon which a multi-pollutant approach should be based. STAPPA and ALAPCO recently completed an analysis to illustrate what nationwide emissions caps could result from the application of the associations' principles. The 2013 caps reflect application of clearly reasonable levels of today's Best Available Control Technology (BACT). An interim deadline of 2008 tracks more closely with attainment dates.

STAPPA and ALAPCO derived the proposed emission caps in the following manner.

- Reviewed recent BACT determinations in new source permits by searching EPA's Clean Air Technology Center RBLC Clearinghouse for utility boilers of more than 250 mmBtu/hr that combust coal, including bituminous, sub-bituminous, anthracite and lignite coal;

- Identified the last five new source permits issued, and their respective SO2 and NOx emission rates, as listed in the RBLC database;
- Selected a “BACT Level for New Plants” of 0.10 lbs/mmBtu for SO2 and 0.07 lbs/mmBtu for NOx based on the review of recent new source permits;
- Reviewed retrofit BACT levels in recent EPA settlement agreements for PSD cases;
- Selected a “Retrofit BACT Level” of 0.15 lbs/mmBtu for SO2 and 0.10 lbs/mmBtu for NOx, which represents a typical settlement agreement BACT level for a retrofit;
- Multiplied the above emission rates by the national heat input for 2001 to calculate the range of emission caps for SO2 and NOx to be achieved in 2013;
- Identified ranges for interim caps (1.51 to 1.87 million tons per year NOx and 3.0 to 4.5 million tons per year SO2, by 2008) based upon their principles in support of quick and effective action and upon their firm belief that such levels are reasonably achievable in the given timeframe.

The result of this analysis is as follows for NOx and SO2:

Pollutant	**National Baseline Emission Levels 2001 (tpy)**	**Proposed National Interim Emission Caps (by 2008) (tpy)**	**Proposed National Emissions Caps Based on Today’s BACT (by 2013) (tpy)**
SO2	10.6 million	3.0 to 4.5 million (57.5 to 71.7% reduction) (0.36 to 0.24 lbs/mm/Btu)	1.26 to 1.89 million (82.1 to 88.1% reduction) (0.15 to 0.10 lbs/mmBtu)
NOx	4.7 million	1.51 to 1.81 million (61.5 to 67.9% reduction) (0.15 to 0.12 lbs/mmBtu)	0.88 to 1.26 million (73.2 to 81.3% reduction) (0.10 to 0.07 lbs/mmBtu)

We recommend that the emission reductions suggested by STAPPA/ALAPCO be considered as candidate control measures. Two specific candidate control measures are discussed below:

Measure EGU1 – Adopt Emission Caps Based on “Retrofit BACT Levels”. This measure would adopt the higher (i.e., less stringent) end of each emission cap range identified by STAPPA/ALAPCO, which reflects the application to all EGUs, new and existing, of the most common emission level for existing sources covered under recent EPA settlement agreements for PSD. These emission caps are based on the “retrofit BACT levels” of 0.15 lbs/mmBtu for SO2 and 0.10 lbs/mmBtu for NOx, to be fully implemented by 2013. STAPPA/ALAPCO also recommended interim emission caps beginning in 2008. Using the recommend national emission caps, we back-calculated the emission rates to be 0.36 for SO2 and 0.15 for NOx, which would apply from 2008 to 2012.

Measure EGU2 – – Adopt Emission Caps Based on “BACT Levels for New Plants”. This measure would adopt the lower (i.e., more stringent) end of each emission cap range reflects the application of new source BACT – based on permits for new units – to all new and existing EGUs. The new source BACT selected for this analysis represents a somewhat conservative level that is generally less stringent than the most recent permit applications for coal-fired boilers. These emission caps are based on the “BACT levels for new plants” of 0.10 lbs/mmBtu for SO2 and 0.07 lbs/mmBtu for NOx, to be fully implemented by 2013. STAPPA/ALAPCO also recommended interim emission caps beginning in 2008. Using the recommend national emission caps, we back-calculated the emission rates to be 0.24 for SO2 and 0.12 for NOx, which would apply from 2008 to 2012.

EMISSION REDUCTIONS

We calculated the approximate range of emission reductions expected from adoption of the STAPPA/ALAPCO strategies by applying the projected heat input for each State by the appropriate BACT level developed by STAPPA/ALAPCO, as follows:

1. Obtained 2002 annual emissions by State from EPA's Clean Air Markets Division website;
2. Obtained projected annual emissions and annual heat input for the CAIR control scenario from the IPM parsed file EXCEL spreadsheets, based on recent IPM runs sponsored by MRPO and VISTAS;
3. Applied the interim and final retrofit BACT levels to the projected annual heat input from the IPM runs to calculate the annual emissions in each year;
4. Applied the interim and final new source BACT levels to the projected annual heat input from the IPM runs to calculate the annual emissions in each year.

Table 2 summarizes the actual annual emissions for 2002, the projected emissions in 2009-2018 based on the proposed CAIR requirements, the interim and final "retrofit BACT levels", and the interim and final "BACT levels for new plants."

COST EFECTIVENESS AND BASIS

Under CAIR, EPA proposed to establish emission caps of 2.7 million tons for SO2 and 1.3 million tons for NOx in the year 2015. Using IPM, EPA estimated that the marginal costs of reductions necessary to meet these caps will be approximately $1,000 per ton of SO2 and $1,500 per ton of NOx. These marginal costs represent the upper bound limits of cost-effectiveness for meeting the proposed emission caps. Average costs for meeting the 2015 emission caps were determined to be $800 for SO2 and $700 for NOx.

EPA also analyzed the cost effectiveness of alternative stringency levels for the emission caps. EPA used the Technology Retrofitting Updating Model (TRUM) to develop marginal cost curves that illustrate the SO2 and NOx emissions in the continental U.S. at various dollar per ton abatement levels (see Reference 12). We used these cost curves to get a preliminary estimate of the marginal costs for the more stringent emission caps identified in this White Paper. We visually estimated the marginal dollar per ton costs associated with the various national SO2 and NOx emission caps recommended by STAPPA/ALAPCO. Shown below are the marginal costs associated as a function of national emission cap

National SO2 Emissions (million tpy)	SO2 Marginal Costs ($/ton)	National NOx Emissions (million tpy)	NOx Marginal Costs ($/ton)
4.5	1,200	1.81	1,400
3.0	1,500	1.51	1,600
1.89	2,500	1.26	1,800
1.26	3,000	0.88	2,100

These cost-effectiveness numbers represent the upper bound limits of cost-effectiveness for meeting the proposed emission caps.

We recommend that more sophisticated analyses be conducted using either TRUM or IPM to provide more refined estimates of the SO2 and NOx marginal costs for the alternative stringency levels identified in this paper.

TABLE 2 – COMPARISON OF ON-THE-BOOKS, ON-THE-WAY, AND CANDIDATE CONTROL MEASURES

SO2 ANNUAL Emissions		On-the-Books (Title IV, NSR, NSPS, State RACT)			Final CAIR				EGU1 Emission Cap (Retrofit BACT Level)		EGU2 Emission Cap (New Source BACT Level)	
State	**Years**	**Heat Input (10^{12} Btu)**	**tons/year**	**Average (lbs/mmBtu)**	**Heat Input (10^{12} Btu)**	**tons/year**	**Average (lbs/mmBtu)**	**Budget for 2010, 2018**	**tons/year**	**Average (lbs/mmBtu)**	**Tons/year**	**Average (lbs/mmBtu)**
IL	2002	1,007	353,699	0.70	1,007	353,699	0.70	-	353,699	0.70	353,699	0.70
	2009		325,401		1,173	295,769	0.50		211,156	0.36	140,771	0.24
	2010							192,671				
	2011-12		312,043		1,217	239,107	0.39		219,060	0.36	146,040	0.24
	2013-15		322,768		1,238	235,946	0.38		92,850	0.15	61,900	0.10
	2016-18		326,147		1,282	241,136	0.38	134,689	96,125	0.15	64,083	0.10
IN	2002	1,259	778,867	1.24	1,259	778,867	1.24		778,867	1.24	778,867	1.24
	2009		705,018		1,478	467,867	0.63		265,994	0.36	177,329	0.24
	2010							254,599				
	2011-12		569,927		1,523	462,373	0.61		274,140	0.36	182,760	0.24
	2013-15		550,659		1,529	393,519	0.51		114,675	0.15	76,450	0.10
	2016-18		559,086		1,534	376,864	0.49	178,219	115,081	0.15	76,721	0.10
MI	2002	759	342,997	0.90	759	342,997	0.90		342,997	0.90	342,997	0.90
	2009		400,157		957	396,991	0.83		172,177	0.36	114,784	0.24
	2010							178,605				
	2011-12		407,790		980	397,643	0.81		176,400	0.36	117,600	0.24
	2013-15		410,116		1,054	397,515	0.75		79,050	0.15	52,700	0.10
	2016-18		413,359		1,258	398,562	0.63	125,024	94,326	0.15	62,884	0.10
OH	2002	1,322	1,132,068	1.71	1,322	1,132,068	1.71		1,132,068	1.71	1,132,068	1.71
	2009		1,420,163		1,645	475,671	0.58		296,080	0.36	197,387	0.24
	2010							333,520				
	2011-12		1,265,364		1,643	312,732	0.38		295,740	0.36	197,160	0.24
	2013-15		1,050,388		1,750	258,852	0.30		131,325	0.15	87,550	0.10
	2016-18		884,704		1,785	215,501	0.24	233,464	133,905	0.15	89,270	0.10
WI	2002	483	191,256	0.79	483	191,256	0.79		191,256	0.79	191,256	0.79
	2009		160,785		585	158,665	0.55		105,307	0.36	70,204	0.24
	2010							87,264				
	2011-12		155,352		615	152,514	0.50		110,700	0.36	73,800	0.24
	2013-15		157,596		640	152,231	0.48		48,000	0.15	32,000	0.10
	2016-18		159,245		691	155,369	0.45	61,085	51,864	0.15	34,576	0.10
MRPO	2002	4,830	2,798,884	1.16	4,830	2,798,884	1.16		2,798,884	1.16	2,798,884	1.16
	2009		3,011,523		5,837	1,794,962	0.61		1,050,713	0.36	700,475	0.24
	2010											
	2011-12		2,710,476		5,978	1,564,369	0.52		1,076,040	0.36	717,360	0.24
	2013-15		2,491,527		6,211	1,438,063	0.46		465,825	0.15	310,550	0.10
	2016-18		2,342,541		6,551	1,387,432	0.42	-	491,301	0.15	327,534	0.10

TABLE 2 (continued)

NOx ANNUAL Emissions		On-the-Books (NOx SIP, Title IV, NSR, NSPS, State RACT)			Final CAIR				EGU1 Emission Cap (Retrofit BACT Level)		EGU2 Emission Cap (New Source BACT Level)	
State	Year	Heat Input (10^{12} Btu)	tons/year	Average (lbs/mmBtu)	Heat Input (10^{12} Btu)	tons/year	Average (lbs/mmBtu)	Budget for 2009, 2018	tons/year	Average (lbs/mmBtu)	Tons/year	Average (lbs/mmBtu)
IL	2002	1,007	174,247	0.35	1,007	174,247	0.35		174,247	0.35	174,247	0.35
	2009-10		135,060		1,173	69,082	0.12	76,230	87,982	0.15	70,385	0.12
	2011-12		139,429		1,217	72,749	0.12		91,275	0.15	73,020	0.12
	2013-15		141,671		1,238	69,169	0.11		61,900	0.10	43,330	0.07
	2016-18		143,158		1,282	71,233	0.11	63,525	64,083	0.10	44,858	0.07
IN	2002	1,259	281,146	0.45	1,259	281,146	0.45		281,146	0.45	281,146	0.45
	2009-10		218,932		1,478	137,080	0.19	108,935	110,831	0.15	88,665	0.12
	2011-12		218,584		1,523	140,930	0.19		114,225	0.15	91,380	0.12
	2013-15		219,833		1,529	97,914	0.13		76,450	0.10	53,515	0.07
	2016-18		221,882		1,534	95,376	0.12	90,779	76,721	0.10	53,704	0.07
MI	2002	759	132,623	0.35	759	132,623	0.35	-	132,623	0.35	132,623	0.35
	2009-10		121,700		957	88,891	0.19	65,304	71,740	0.15	57,392	0.12
	2011-12		123,880		980	89,554	0.18		73,500	0.15	58,800	0.12
	2013-15		126,057		1,054	91,025	0.17		52,700	0.10	36,890	0.07
	2016-18		127,872		1,258	98,685	0.16	54,420	62,884	0.10	44,019	0.07
OH	2002	1,322	342,999	0.52	1,322	342,999	0.52	-	342,999	0.52	342,999	0.52
	2009-10		272,499		1,645	109,254	0.13	108,667	123,367	0.15	98,693	0.12
	2011-12		266,017		1,643	100,357	0.11		123,225	0.15	98,580	0.12
	2013-15		268,678		1,750	89,195	0.10		87,500	0.10	61,250	0.07
	2016-18		268,413		1,785	83,129	0.09	90,556	89,270	0.10	62,489	0.07
WI	2002	483	88,970	0.37	483	88,970	0.37	-	88,970	0.37	88,970	0.37
	2009-10		59,301		585	45,323	0.15	40,759	43,878	0.15	35,102	0.12
	2011-12		58,088		615	43,340	0.14		46,125	0.15	36,900	0.12
	2013-15		59,333		640	43,754	0.14		32,000	0.10	22,400	0.07
	2016-18		60,665		691	45,701	0.13	33,966	34,576	0.10	24,203	0.07
MRPO	2002	4,830	1,047,484	0.43	4,830	1,047,484	0.43	-	1,047,484	0.43	1,047,484	0.43
	2009-10		807,492		5,837	449,630	0.15		437,797	0.15	350,238	0.12
	2011-12		805,998		5,978	446,930	0.15		448,350	0.15	358,680	0.12
	2013-15		815,572		6,211	391,057	0.13		310,550	0.10	217,385	0.07
	2016-18		821,990		6,551	394,124	0.12	-	327,534	0.10	229,274	0.07

TABLE 2 (continued)

NOx OZONE Season Emissions		On-the-Books (NOx SIP, Title IV, NSR, NSPS, State RACT)			Final CAIR				EGU1 Emission Cap (Retrofit BACT Level)		EGU2 Emission Cap (New Source BACT Level)	
State	Year	Heat Input (10^{12} Btu)	tons/year	Average (lbs/mmBtu)	Heat Input (10^{12} Btu)	tons/season	Average (lbs/mmBtu)	Budget for 2009, 2018	tons/season	Average (lbs/mmBtu)	tons/season	Average (lbs/mmBtu)
IL	2002	477	71,235	0.30	477	71,235	0.30		71,235	0.30	71,235	0.30
	2009-10		31,935		518	30,277	0.12	30,701	38,872	0.15	31,097	0.12
	2011-12		32,829		537	32,083	0.12		40,275	0.15	32,220	0.12
	2013-15		34,052		554	31,314	0.11		27,700	0.10	19,390	0.07
	2016-18		34,470		564	31,214	0.11	28,981	28,217	0.10	19,752	0.07
IN	2002	558	114,084	0.41	558	114,084	0.41		114,084	0.41	114,084	0.41
	2009-10		60,857		642	58,657	0.18	45,952	48,167	0.15	38,534	0.12
	2011-12		59,595		668	61,285	0.18		50,100	0.15	40,080	0.12
	2013-15		60,768		667	42,406	0.13		33,350	0.10	23,345	0.07
	2016-18		61,611		666	40,820	0.12	39,273	33,295	0.10	23,306	0.07
MI	2002	350	58,237	0.33	350	58,237	0.33	-	58,237	0.33	58,237	0.33
	2009-10		38,039		408	37,248	0.18	28,971	30,603	0.15	24,483	0.12
	2011-12		40,592		420	37,911	0.18		31,500	0.15	25,200	0.12
	2013-15		41,637		443	38,421	0.17		22,150	0.10	15,505	0.07
	2016-18		42,427		538	42,629	0.16	24,142	26,844	0.10	18,819	0.07
OH	2002	590	155,364	0.53	590	155,364	0.53	-	155,364	0.53	155,364	0.53
	2009-10		48,993		705	44,539	0.13	45,664	52,910	0.15	42,328	0.12
	2011-12		47,084		714	42,526	0.13		53,550	0.15	42,840	0.12
	2013-15		47,769		761	37,896	0.10		38,050	0.10	26,635	0.07
	2016-18		46,057		774	35,888	0.09	39,945	38,682	0.10	27,077	0.07
WI	2002	223	40,454	0.36	223	40,454	0.36	-	40,454	0.36	40,454	0.36
	2009-10		26,033		254	19,604	0.15	17,987	19,057	0.15	15,245	0.12
	2011-12		24,732		268	18,743	0.14		20,100	0.15	16,080	0.12
	2013-15		25,547		280	19,090	0.14		14,000	0.10	9,800	0.07
	2016-18		26,184		304	19,794	0.13	14,989	15,187	0.10	10,361	0.07
MRPO	2002	2,198	439,374	0.40	2,198	439,374	0.40	-	439,374	0.40	439,374	0.40
	2009-10		205,856		2,528	190,325	0.15		189,609	0.15	151,687	0.12
	2011-12		204,831		2,607	192,548	0.15		195,525	0.15	156,420	0.12
	2013-15		209,773		2,705	169,127	0.13		135,250	0.10	94,675	0.07
	2016-18		210,748		2,845	170,345	0.12	-	142,264	0.10	99,585	0.07

TABLE 2 (continued)

Notes for Table 2:

1. 2002 heat input and tons/year came from EPA's CAMD Emission Quick Reports (retrieved 08/30/05)
2. On-the-books emissions came from IPM summary table DraftResultsToCENRAP VISTASII_BC.xls
3. 2009 and 2018 heat input and annual emissions came from LADCO, which provided IPM parsed files converted to NIF format:
   - ipm2009.tar.gz and ipm2018.tar.gz
4. 2012 and 2015 heat input and emissions came from LADCO (summary tables):
   - StateLevelSummaryM03.xls for 2012
   - StateLevelEmissionSummary.txt and StateLevelHeatInputSummary.txt for 2015
5. EPA Budget for SO2 came from May 12, 2005 Federal Register, page 25329
6. EPA Budget for Annual NOx came from May 12, 2005 Federal Register, page 25348-25349
7. EPA Budget for Ozone Season NOx came from May 12, 2005 Federal Register, page 25348-25349
8. Proposed EGU1 and EGU2 emission caps were calculated using IPM forecasted heat inputs and recommended average lbs/mmBtu shown in the table

TIMING OF IMPLEMENTATION

The final CAIR rule was released in May 2005. EPA provides States with 18 months to have approved SIPs in place. In the proposed CAIR rule, EPA determined that three years was a reasonable amount of time to allow companies to install emission controls that could be used to comply with the first phase requirements of the proposed rule. Thus, affected sources would not have to comply with the first phase of the CAIR rule requirements until January 2010. In the final CAIR rule, EPA requires NOx controls to be in place by 2009 and SO2 controls by 2010. The compliance date for the second phase of CAIR is 2015. EPA indicated that one of the key factors constraining it from specifying earlier deadlines is the availability of boilermaker labor to install air pollution control technology

The STAPPA/ALAPCO recommended interim emission caps beginning in 2008 to more closely track with attainment dates for many areas. STAPPA/ALAPCO also recommended that full implementation of its more stringent emission caps by 2013. They cited an analysis conducted by the Institute of Clean Air Companies that determined that there is sufficient availability of boilermaker labor to install pollutions controls five yeas earlier than EPA assumed.

RULE DEVELOPMENT ISSUES

There are many implementation issues that would need to be addressed. An emissions cap-and-trade program (with more stringent and timely reductions than the proposed CAIR program) is best implemented on a national or regional basis. The MRPO States would need to work with EPA in establishing a more stringent/timely national trading program, other RPO's in establishing a more stringent/timely regional trading program, or with each other in establishing a MRPO-region trading program. Alternatively, MRPO States could develop state-only regulations (analogous to the North Carolina Clean Smokestacks Act) to establish the STAPPA/ALAPCO recommended retrofit BACT and new source BACT levels for EGUs within their State.

GEOGRAPHIC APPLICABILITY

The suggested STAPPA/ALAPCO cap-and-trade program would apply to all EGUs in the MRPO region. An alternative scenario could be developed to also apply the STAPPA/ALAPCO BACT levels to EGUs outside the region.

SEASONAL APPLICABILITY

In addition to emission reductions during the ozone season to attain the ozone NAAQS, reductions are needed throughout the year to address the PM2.5 NAAQS and regional haze. Thus, the candidate control measures are intended to be applied on an annual basis for SO2 and NOx. In addition, we calculated NOx emission caps for the ozone season using the same EGU1 and EGU2 lbs/mmBtu values as for the annual case (.i.e, "retrofit BACT levels" of 0.15 lbs/mmBtu for SO2 and 0.10 lbs/mmBtu for NOx, to be fully implemented by 2013; "BACT levels for new plants" of 0.10 lbs/mmBtu for SO2 and 0.07 lbs/mmBtu for NOx, to be fully implemented by 2013.)

AFFECTED SCCs

The primary SCCs affected by this candidate control measure are:

1-01-002-xx External Combustion, Electric Generation, Bituminous and Subbituminous Coal

However, the following SCCs for the EGU sector may also be affected:

1-01-xxx-xx External Combustion, Electric Generation
2-01-xxx-xx Internal Combustion, Electric Generation

REFERENCES

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4. Synapse Energy Economics, Inc. *Survey of Clean Power and Energy Efficiency Programs*. January 12, 2002.
5. U.S. EPA. *NOx Budget Trading Program: 2003 Progress and Compliance Report*. August 2004.
6. 70 FR 25162-25404. *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule): Final Rule*. May 12, 2005.
7. U.S. EPA. *Clean Air Interstate Rule (CAIR): Reducing Power Plant Emissions for Cleaner Air, Healthier People, and a Strong America*. March 2005.
8. U.S. EPA. *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model – Section 3.9 Existing Environmental Regulation*. EPA 430/R-02-004. March 2002.
9. E.H. Pechan and Associates. EXCEL Spreadsheets with IPM Parsed Output for 2009 and 2018 Unit-Level Base and Control Scenarios.
10. STAPPA/ALAPCO. Letter to EPA Air Docket providing comments on the Proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (69 Federal Register 4566. March 30, 2004.
11. STAPPA/ALAPCO. *Analysis of STAPPA and ALAPCO's May 7, 2002 Principles for a Multi-Pollutant Strategy for Power Plants*. March 15, 2004.
12. EPA Clean Air Markets Division. *Analysis of the Marginal Cost of SO2 and NOx Reductions*. January 28, 2004.

Attachment 1 – NOx Control Technologies for Coal-Fired Boilers

Technology	Description	Applicability	Performance	Cost ($/ton)
Burner Modifications	Burner air and/or fuel modifications to improve air/fuel interaction	Most units	10 to 30% NOx reduction	100 - 200
Fuel Reburn	Inject portion of the fuel into the furnace downstream of burner zone. Usually requires OFA to complete combustion	Most units. Furnace height (residence time) may restrict some applications	20 to 30% NO_x reduction for Fuel-Lean Gas Reburning (no OFA), and 30 to 60% reduction for conventional reburning.	500 – 2000 (highly dependent on cost of reburn fuel)
Hydrocarbon-enhanced SNCR	Inject small amount of natural gas to create radicals that enhance SNCR effectiveness at 1700 to 2000 °F. Emerging technology.	Most units. Can use more NH_3 with less slip.	40 to 60% NO_x reduction	500 – 1000
Low-NOx Burners	Burners designed to produce lower NO_x emissions – “staged” combustion	Most boilers already have LNB.	30 to 50% NO_x reduction	200 – 1000
Overfire Air	Form of “staged” combustion. Divert portion of the air from the windbox to OFA ports installed above the burners.	Most units. Furnace height may restrict some applications	20 to 40% NO_x reduction	250 – 600
Oxygen-enhanced combustion modification	Improve effectiveness of OFA operation by injecting O_2 into fuel-rich flames. Operate more fuel-rich without the problems. Emerging technology.	Best applied with new OFA system designed to achieve stoichiometric air-fuel ratio < 0.8.	30-50% beyond OFA	1000 – 2000
Rich Reagent Injection	SNCR system with reagent injection into a fuel rich zone of the OFA system. This variation of SNCR is still under demonstration	Most units. Modeling required to determine injection locations.	20 to 30% additional NO_x reduction beyond OFA.	800 – 1500
Selective Catalytic Reduction (SCR)	Ammonia added upstream of catalytic reactor installed upstream of air preheater (conventional), downstream of a hot ESP (low dust), or downstream of the cold ESP (tail end).	Most units. Space availability may constrain some options. High sulfur fuels more challenging	70 to 90+% NO_x reduction	1500 – 2000
Selective Non-catalytic Reduction (SNCR)	Inject ammonia-based reagent into upper furnace (1700-2000 degrees F) to destroy NO_x.	Most. Residence time and temperature characteristics are important.	25 to 50% NO_x reduction, depending on the furnace temperature and time for reaction.	800 - 1500

References:

Reaction Engineering International, and Energy&Environmental Strategies. *Summary of Emission Controls Available for Large Stationary Sources of NOx and PM*. Prepared for the Western Governor’s Association. June 30, 2003.

Attachment 2 – SO2 Control Technologies for Coal-Fired Boilers

Technology	Description	Applicability	Performance	Cost ($/ton)
Physical Coal Cleaning	Uses physical processes to remove pyrites (inorganic sulfur compounds) in coal	Available for all units	10-40% reduction in SO2	
Chemical Coal Cleaning	Uses chemical processes to remove pyrites (inorganic sulfur compounds) and organic sulfur in coal	Available for all units	50-85% reduction in SO2	
Switch to Low Sulfur Coal	Uses low-sulfur western or other coals	Available for all units	50-80% reduction in SO2	
Limestone forced oxidation system (LSFO)*	LSFO is a process based on wet limestone scrubbing which reduces scaling and eliminates need for landfilling of the waste product. Currently the preferred FGD technology worldwide.	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	200-500 for units > 400 MW 500-5,000 for units <400 MW
Magnesium enhanced lime system (MEL)*	In the MEL process, slaked lime, containing calcium hydroxide [Ca(OH)2] and a portion of magnesium hydroxide [Mg(OH)2], is used to react with SO2.	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	200-500 for units > 400 MW 500-5,000 for units <400 MW
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	150-300 for units > 200 MW 500-4,000 for units <200 MW

References:

Ravi K. Srivastava, U.S. EPA. *Controlling SO2 Emissions: A Review of Technologies.* EPA/600/R-00/093. November 2000

U.S. EPA. *Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization.* EPA-452/F-03-034.

Illinois Environmental Protection Agency. *Fossil Fuel-Fired Power Plants – Report to the House and Senate Environment and Energy Committees*. IEPA/BOA/04-020. September 2004.

Notes:

* Srivastava indicates that LSFO, MEL, and LSD have been the dominant processes in terms of electric generating capacity equipped with FGD over the last 30 years. See EPA/600/R-00/093 for a more complete discussion of these processes, as well as other wet, dry, and regenerable FGD processes.