EVALUATION OF THE MIDWEST RPO INTERIM MEASURES AND EGU1 AND EGU2

Submitted On Behalf of
Midwest Ozone Group

Submitted to
Midwest Regional Planning Organization

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I. INTRODUCTION

In January 2005, the Midwest Regional Planning Organization (MRPO) issued a White Paper that outlined a possible set of control measures that electric generating units within the states of Illinois, Indiana, Michigan, Ohio and Wisconsin would have to meet beginning in 2008 and with final implementation being 2013. These control measures would establish regional emission caps based upon specified emission rates for both NOx and SO2. There are two sets of emission rates that are described in the White Paper, which can be referred to as Intermediate Measures (IM) 1 and 2 and Electric Generating Unit (EGU) 1 and 2.

In IM1, a regional cap is proposed based upon emission rates of 0.36 and 0.15 lbs/mmbtu, respectively, for SO2 and NOx. The second intermediate measure, referred to as IM2, proposes a regional cap based upon emission standards of 0.24 and 0.12 lbs/mmBtu, respectively, for SO2 and NOx. These IM regional caps would apply from 2008 to 2012.

In terms of EGU1, a regional cap is proposed based upon emission rates 0.15 and 0.10 lbs/mmbtu, respectively, for SO2 and NOx. The final EGU scenario, identified as EGU2, proposes a regional cap based upon emission rates of 0.10 and 0.07 lbs/mmbtu, respectively, for SO2 and NOx. Implementation of these EGU caps would begin in 2009 with full implementation in 2013. As you can see there is an overlap between IM and EGU scenarios. For the purposes of this analysis, we evaluated compliance for the IM1 and IM2 in 2012 and compliance for EGU1 and EGU2 in 2013.

Of particular note, during this 2012 – 2013 time period the On-the-Books emission rates that would be in effect within the 5-State Region attributed to the Clean Air Interstate Rule (CAIR) are 0.58 and 0.15 lbs/mmbtu, respectively, for SO2 and NOx.

The purpose of this analysis is to provide the reader with a comparative evaluation of the compliance implications of meeting the reduction targets proposed by IM1 & IM2 and EGU1 & EGU2 by fossil electric generating units in the 5-State Region. This analysis not only evaluates the level of capital investment and annual compliance costs attributed to each scenario, but also illustrates the marginal cost of control for SO2 and NOx, the level of potential capacity at-risk in achieving the reduction targets of each scenario and the level of local coal that could be displaced due to compliance.

In terms of modeling, each scenario was modeled independent of each other; therefore, there were no compliance phases. In addition, due to the stringency of EGU1 and EGU2, the modeling was in two phases: (i) initial compliance to meet the EGU caps without regard to costs; and, (ii) evaluation of the expected costs to meet EGU caps.

II. METHODOLOGY

To undertake this study, we employed the *Emission-Economic Modeling System (EEMS)*, a computer model designed to undertake emission and economic analyses of environmental polices and regulations. The modeling system contains a rich database describing the electric generating sector, covering unit design and operating characteristics, environmental control equipment and emission rates.

In general, *EEMS* identifies a combination of control options (technology versus allowances) that approximates the least cost solution for a given utility system or regulatory (trading) regime. The order in which individual units are assumed to deploy their initial compliance option is determined by their dispatch order and generation costs with the cheapest units are assumed to deploy control technology first. The total tons reduced are then compared to the reduction target. If calculated emissions are above the target, *EEMS* then systematically assigns more stringent control technology, in order of increasing generation costs, until the reduction target is achieved. Likewise, if the calculated emissions are significantly below the emission target, *EEMS* will begin to remove the most expensive control technology until the emissions a very close to the cap, taking into account any required control margin to account for unexpected events.

Regional NOx and SO2 Budgets: As mentioned earlier, the stipulated emission rates for both IM1 & IM2 and EGU1 & EGU2 would be used to establish regional emission caps or budgets for affected electric generating units within the 5-State Region. The computed budgets for NOx and SO2 for each scenario that were modeled are presented in Table 1.

TABLE 1
REGIONAL NOx AND SO2 BUDGETS
(tons)

Scenario	NOx	SO2
CAIR	399,895	1,046,659
IM 1	376,037	860,956
IM 2	300,830	573,971
EGU 1	250,069	358,732
EGU 2	175,484	239,154

The regional NOx budget for both IM and EGU scenarios was determined by following Clean Air Interstate Rule (CAIR) allocation process, as outlined in the final rule. The SO2 regional budget for both IM and EGU scenarios was based upon an alternative to the CAIR allocation process, which is based upon Title IV – Phase II allocations. The alternative allocation process used the average heat input for the years 2000 – 2004 from EPA's Continuous Emission Monitoring (CEM) data for Acid Rain units. Appendix A presents a description of the method and data used to compute both NOx and SO2 budgets.

Affected units, which are defined as units that would have to meet the reduction targets of IM or EGU scenarios, are fossil units >25 MW that sell electricity to the grid. Under the proposed regulatory regime evaluated in this analysis, electric generators would be able to bank and trade SO2 and NOx allowances within the 5-State Region, but no Title IV SO2 allowances could be carried over for compliance.

Generation and Fuel Assumptions: In this analysis, *EEMS* developed a generation forecast for electric power sector fossil generating units within the following North America Electric Reliability Council (NERC) regions: East Central Area Reliability Coordination Agreement (ECAR); Mid-America Interconnected Network (MAIN) and Mid-Continent Area Power Pool (MAPP). The basis of this forecast was the projected regional electric demand by fuel type from Energy Information Administration's (EIA) *Annual Energy Outlook 2005 (AEO2005)*. In addition, future regional coal and gas prices were also based upon EIA's *AEO2005*.

Compliance and Control Technology Choices: Those control options that were evaluated in this analysis to meet the reduction targets of either IM1 & IM2 or EGU1 & EGU2 are as follows:

- SO2 Controls
  - Base Wet Flue Gas De-Sulfurization (FGD) System with SO2 removal efficiencies of 90 and 95 percent for Powder River Basin (PRB)/sub-bituminous and bituminous coals, respectively;
  - High Performance Wet FGD System with SO2 removal efficiencies of 94 and 98 percent for PRB/sub-bituminous and bituminous coals, respectively;
  - FGD Upgrade for existing FGD systems with removal efficiencies at or below 90 percent to 93 percent;
  - Fuel Switching from a high sulfur coal to a low sulfur PRB coal; and,
  - Fuel Switching Existing and Retrofitted FGD (FGD-FS) systems a fuel switch from a high sulfur bituminous coal to a low sulfur coal from the Powder River Basin of Wyoming .

- NOx Controls
  - Combustion Modifications install controls on units that exceed specified NOx emission rates;[1]
  - Selective Non-Catalytic Reduction (SNCR) with NOx removal efficiencies upwards to 45 percent depending on size; and,
  - Selective Catalytic Reduction (SCR) limited to 90 percent removal or specified floors depending on coal type.

The selection of specific compliance technologies by the model is not intended to replicate an individual company's compliance decisions; however, the model results are based upon the application of a set of control assumptions that are uniformly applied across the entire boiler population within a specific (geographical) jurisdiction based upon unit specific information contained in the model's data base.

Capital and operating costs were developed based upon information in the public domain about recent control technology installations. It should be noted, that the above mentioned

[1] Combustion Modifications were modeled to be used in combination with either SNCR or SCR.

control assumptions represent realistic assumptions, in terms of applicability and performance. Further details of these control assumptions and costs are described in Appendix B.

III. REGIONAL EMISSIONS AND CONTROL CAPACITY

Electric generating units within the 5-State Region are currently complying with regulatory requirements of Title IV, NOx SIP Call, specific NSR consent decrees, as well as specific BACT requirements for new sources. Beginning in 2009, electric generating units within the 5-State Region will have to meet the targets and timetables specified in CAIR. To meet these regulatory initiatives, electric generators within the five states have or will be installing SO2 and NOx control technologies through 2012, as shown in the table below.

TABLE 2

SUMMARY OF REGIONAL ELECTRIC GENERATING SO2 AND NOX CONTROLLED CAPACITY: 2012

Element	Capacity (GW)	% of Regional Capacity
Coal-fired Capacity (>25 MW)	82.7	
FGD	40.7	49.2
SCR	48.6	59.8
SNCR	16.5	19.9

In 2012, the electric generators are expected to have 82.7 GW of coal-fired capacity available within the 5-State Region. In response to CAIR and other On-the-Books regulatory mandates by 2012, 49.2 percent (or 40.7 GW) of this existing capacity is expected to have FGD systems operating. Also by the end of 2009, 43 percent of the region’s coal-fired capacity will be burning low sulfur coal from the PRB.

In terms of NOx controls, by 2012 almost 60 percent of the region’s coal-fired capacity (48.6 GW) will be equipped with SCR technology, while an additional 20 percent (16.5 GW) of the region’s coal-fired capacity will have SNCR technology. This would mean almost 80 percent of the region’s 2012 coal-fired capacity will have some kind of post-combustion NOx controls.

The installation of these SO2 and NOx controls are expected to have a significant impact on both SO2 and NOx emissions within the five states between 2003 and 2012, as illustrated in the Table 3.

TABLE 3

REGIONAL EGU SO2 AND NOx EMISSIONS: 2003, 2009 and 2012

Parameter	2003	2009	2012
Heat Input: TBtu	4,817	5,871	5,991
SO2: Tons	2,896	2,322,306	1,631,714
SO2: lbs/mmbtu	1.20	0.79	0.54
NOx: Tons	921,884	403,918	380,050
NOx: lbs/mmbtu	0.38	0.14	0.13

As shown above between 2003 and 2012 regional electric generating fossil heat input is projected to increase by 24.4 percent, while both SO2 and NOx emissions are expected to decline by 43.7 and 58.8 percent, respectively. These emission decreases illustrate the effect current and future On-the-Books regulations are expected to have upon regional emissions.

IV. COMPLIANCE EFFECTS OF MEETING IM1 AND IM2

In order to meet the IM1 and IM2 reduction targets in 2012, electric generators within the 5-State Region would have to make an initial capital investment of $9.5 billion and $15.5 billion, respectively on SO2 and NOx control technologies, as shown in Table 4.[2] Generators within these five states would incur annualized compliance costs in 2012 of $2.0 billion and $3.2 billion, respectively for IM1 and IM2 in order to achieve their respective regional SO2 and NOx caps.[3]

TABLE 4

IM1 AND IM2 COMPLIANCE COSTS AND EMISSION REDUCTIONS IN THE FIVE STATES: 2012
(2003$)

Simulation	Capital	Annualized	SO2 MC ($/ton)	NOx MC ($/ton)	SO2 Emissions	NOx Emissions
CAIR			1,052	2,584	1,631,000	380,000
IM1	9.5B	2.0B	2,598	4,122	860,000	376,000
IM2	15.5B	3.2B	5,029	4,669	573,000	300,000

Note: 1. MC represents the marginal cost of control, which is the cost of the last unit to achieve compliance.

These investments will reduce both SO2 and NOx emissions within the five states from the projected CAIR levels, as shown in Table 4. However, to achieve both IM1 and IM2 SO2

[2] Initial capital investment is defined as the capital required to SO2 and NOx control equipment that would be in service by 2012.
[3] Annualized compliance costs are defined as the annual capital charge (including taxes and insurance), annual operation and maintenance costs, changes in fuel costs generators need to pay to operate SO2 and NOx control equipment.

caps, SO_2 control technology would have to be installed on units between 56 and 60 years old. As shown in Table 5, FGD capacity within the 5-State Region would reach 59.1 GW under IM1 and 75.4 GW under IM2, which translates into 71.5 percent and 91.2 percent of region's total coal-fired capacity being equipped with FGD systems, respectively. In addition, under IM1 2.2 GW of existing FGD capacity and 4.6 GW of existing FGD capacity would be upgraded to achieve a SO_2 removal efficiency of 93 percent (FGD – Upgrade).

TABLE 5

FIVE STATE SO2 AND NOX CONTROL CAPACITY UNDER IM1 & IM2: 2012 (GW)

Technology	5-State (CAIR)	IM1	IM2
FGD	40.7	59.1	75.4
FGD - Upgrade	1.5	2.2	4.6
SCR	48.6	55.3	61.5
SNCR	16.5	9.0	5.8

In terms of NOx, projected SCR capacity under IM1 would reach 55.3 GW, while under IM2 SCR capacity would be operating on 75.4 GW. This SCR capacity translates into almost 67 percent and 75 percent of the region's coal-fired capacity operating SCRs under IM1 and IM2, respectively.

The major consequence of deploying SO_2 control technology on these older units significantly raises the marginal costs of control, as depicted in Table 4, to meet the IM1 and IM2 caps. This technology deployment under IM1 and IM2 potentially puts at risk (units that could be retired) 4.8 GW and 8.5 GW of coal-fired capacity, respectively in the 5-State Region. Another consequence relates to the IM1 & IM2 NOx caps, which forces generators to switch from less expensive SNCR technology under CAIR to more expensive SCR technology to meet the reduction targets of both IM measures. This technological shift results in a marginal cost of compliance of $4,669/ton of NOx removed.

V. COMPLIANCE EFFECTS OF MEETING EGU1 AND EGU2

Initial Evaluation of EGU1 and EGU2

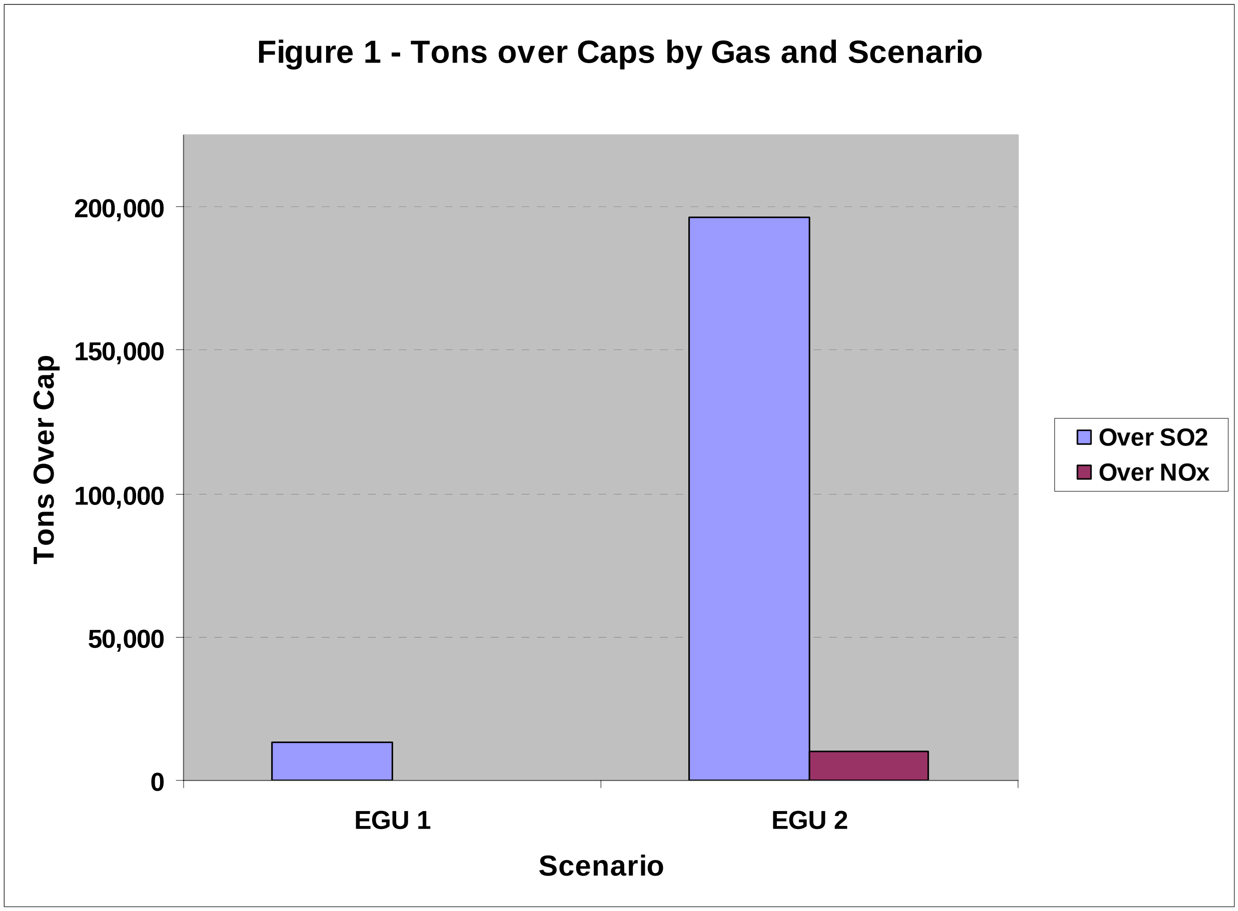
To meet the more stringent EGU1 and EGU2, electric generators in the five states would require an initial capital investment of $20.4 billion and $20.5 billion for SO_2 and NOx controls, respectively for EGU1 and EGU2, as shown in Table 6. This capital investment for both EGU1 and EGU2 would translate into an annualized compliance cost of $5.2 billion in 2013, which is more than double the compliance costs for IM1 and more than one and half times greater than the compliance costs for IM2. The stringency of these two caps, and the restrictive trading regime, can be illustrated by the marginal cost of control for both SO_2 and NOx, as demonstrated in Table 6.

TABLE 6

INITIAL EGU1 AND EGU2 COMPLIANCE COSTS AND EMISSION REDUCTIONS IN THE FIVE STATES: 2013
(2003$)

Simulation	Capital	Annualized	SO2 MC ($/ton)	NOx MC ($/ton)	SO2 Emissions	NOx Emissions
CAIR (2012)			1,052	2,584	1,631,000	380,000
EGU1	20.4B	5.2B	23,472	10,169	372,000	250,000
EGU2	20.5B	5.2B	23,472	12,377	372,000	249,000

However, even with this level of capital investment in control technologies and very aggressive control assumptions, the SO2 emission reductions electric generators would achieve under both EGU1 and EGU2 *would not allow* them to meet the SO2 emission caps (See Table 1) in 2013. As shown above in Table 6, electric generator SO2 emissions in 2013, in the 5-State Region for both EGU1 and EGU2 would be 372,000 tons. These 2013 SO2 emission levels would put electric generators almost 13,000 tons above the EGU1 SO2 cap and approximately 133,000 tons above the EGU2 SO2 cap. In addition to not meeting either EGU1 or EGU2 SO2 caps in 2013, electric generators in the five states would also fail to meet the EGU2 NOx cap by almost 74,000 tons. This emission shortfall can be illustrated by Figure 1.



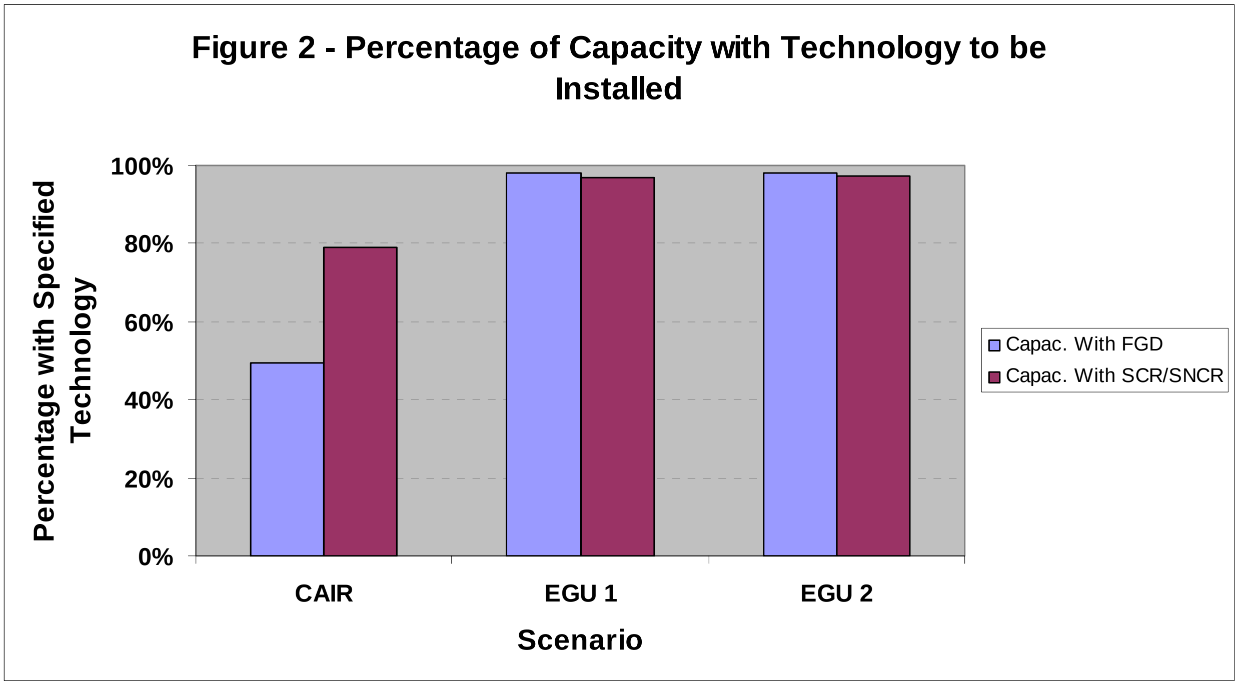
As shown in Table 7, of the 82.3 GW of coal-fired expected to be available in 2013, 80.8 GW or 98.2 percent would be equipped with FGD systems under both EGU1 and EGU2. This level of controlled FGD capacity explains why there is no change in SO2 emission levels between EGU1 and EGU2, because all units that can receive FGD systems have installed these systems by 2013.

TABLE 7

FIVE STATE SO2 AND NOX CONTROL CAPACITY UNDER EGU1 & EGU2: 2013 (GW)

Technology	5-State (CAIR)	EGU1	EGU2
FGD	40.7	80.8	80.8
FGD - FS	0	18.6	18.6
FGD - Upgrade	1.5	3.6	3.6
SCR	48.6	73.6	74.0
SNCR	16.5	6.1	6.2

This same trend follows for NOx controls, in which approximately 97 percent of the five state coal-fired capacity will have some form of post-combustion controls (SCR or SNCR) operating in 2013. The only units that do not receive SO2 and/or NOx controls are either very small (<50 MW) or very old (>60 years old) under EGU1 and EGU2.[4] Figure 2 provides an illustration of the level of SO2 and NOx controlled capacity to total capacity in 2013.



In addition to the level of FGD capacity that will be operating within the five states in 2013, 18.6 GW of this FGD capacity would have to switch from a high sulfur coal to low sulfur PRB coal in an attempt to meet the 2013 EGU1 and EGU2 SO2 caps. Also, 3.6 GW of existing FGD capacity would upgrade their SO2 removal efficiencies to 93 percent. In an attempt to meet these SO2 and NOx caps under EGU1 and EGU2, 9.9 GW of existing coal-fired capacity, with ages between 56 and 60 years old (in 2013), would be required to install FGD systems, potentially putting this capacity "at risk" of being retired.

As discussed previously, even with this level of controlled capacity and very aggressive control options, electric generators within the five states were unable to attain the 2013 SO2 caps for EGU1 and EGU1. The question then remains, why these electrical generators *can not* meet the caps of EGU1 and EGU2? The primary factors are growth in electrical demand and technological limitations. Emission caps in all cap and trade programs are based upon some kind of historical baseline (e.g., average heat input from 2000 to 2004) that requires affected sources to meet these limits in some future time period. Between the time of establishing the caps and time of compliance, electrical demand will have increase. This increase in electrical demand means greater emission reductions have to be achieved in order to meet the cap limits.

[4] Two units that did not receive SO2 and NOx controls are new Marion 1,2, & 3, which is an FBC unit, and Wabash River 1, which is an IGCC unit.

Consequently, the effective removal emission rate (emission reductions) to achieve the cap has to be below the specified emission rate that is used to establish the cap. For the EGU2 SO2 cap, which is based upon 0.10 lbs/mmbtu, the overall effective emission rate that electric generators in the five states would have to achieve to meet the cap would have to be 0.08 lbs/mmbtu. However, even employing very realistic technology assumptions the best overall effective emission rate electric generators can achieve in 2013 in the five states is 0.12 lbs/mmbtu.

Expected Costs to Meet EGU1 and EGU2

To meet the EGU1 and EGU2 caps in 2013, a specific amount of coal-fired capacity would have to be retired, since SO2 emissions exceed both cap levels and there are *no additional* controls that could be installed on the existing 2013 coal-fired capacity. As shown in Table 8, almost 0.7 GW of existing coal-fired would have to retired to meet the EGU1 SO2 cap; however, an additional 9.9 GW of older capacity (age >60 years old) could be "at risk" due to technology retrofits. In terms of EGU2, as shown in Table 8, approximately 30.2 GW of region's existing coal-fired capacity would have to be retired in order to achieve the 2013 EGU2 SO2 cap, with an additional 4.7 GW of capacity "at risk" due to age.

TABLE 8

POTENTIAL RETIREMENT CAPACITY UNDER EGU1 AND EGU2 (GW)

Scenario	Capacity Retired to Meet Caps	At Risk Capacity Due to Age	Total Potential Retirement Capacity
EGU1	0.7	9.9	10.6
EGU2	30.2	4.7	34.9

Assuming, the above-mentioned total potential retirement capacity under both EGU1 and EGU2 is retired its 2013 generation would have to be replaced. This replacement power or electrical demand would be supplied through imports from surrounding NERC regions, increased operation of existing natural gas-fired combined cycle capacity in the affected NERC regions (ECAR, MAIN and MAPP) and the construction of new gas-fired combined cycle capacity in the affected NERC regions. The 2013 net incremental replacement capacity costs for EGU1 and EGU2 would be $1.4 billion and $4.9 billion, respectively, as shown in Table 9. A brief discussion of the replacement cost methodology can be found in Appendix C.

With the retirements of the above-mentioned coal-fired capacity, their technology control costs would be removed from the region's annualized compliance costs displayed in Table 6. Therefore, the net SO2 and NOx 2013 technology control costs, which take into retirements to meet the EGU1 and EGU2 caps, would be $3.6 billion and $2.2 billion, respectively. As shown in Table 9, electric generators in the five states would be required to expend almost $5.0 billion in 2013 to meet the EGU1 cap. If electric generators would be required to meet the EGU2 cap in 2013, they would be required to spend $7.1 billion. Appendix C provides a breakdown of these costs by state.

TABLE 9

ANNUALIZED COMPLIANCE COSTS TO MEET EGU1 AND EGU2 CAPS: 2013 (2003$)

Scenario	Replacement Power	Technology	Total
EGU1	1.4B	3.6B	5.0B
EGU2	4.9B	2.2B	7.1B

Throughout this section we have discussed unit retirements and fuel switches in order to meet the EGU1 and EGU2 caps and their respective compliance costs. A direct impact of unit retirements and fuel switching existing/retrofitted FGDs from high sulfur coal to PRB coal is the effect on Illinois, Indiana and Ohio coal shipments to electric generators. Under EGU1, the projected retirements and fuel switches would displace 42.6 million tons of Illinois, Indiana and Ohio coal in 2013. In terms of EGU2, the projected retirements and fuel switches would displace almost 47.8 million tons of Illinois, Indiana and Ohio coal. A brief discussion of the assumptions and methodology used in computing the level of displaced coal can be found in Appendix C.

VI. SUMMARY OF IM1 & IM2 AND EGU1 & EGU2 COMPLIANCE COSTS

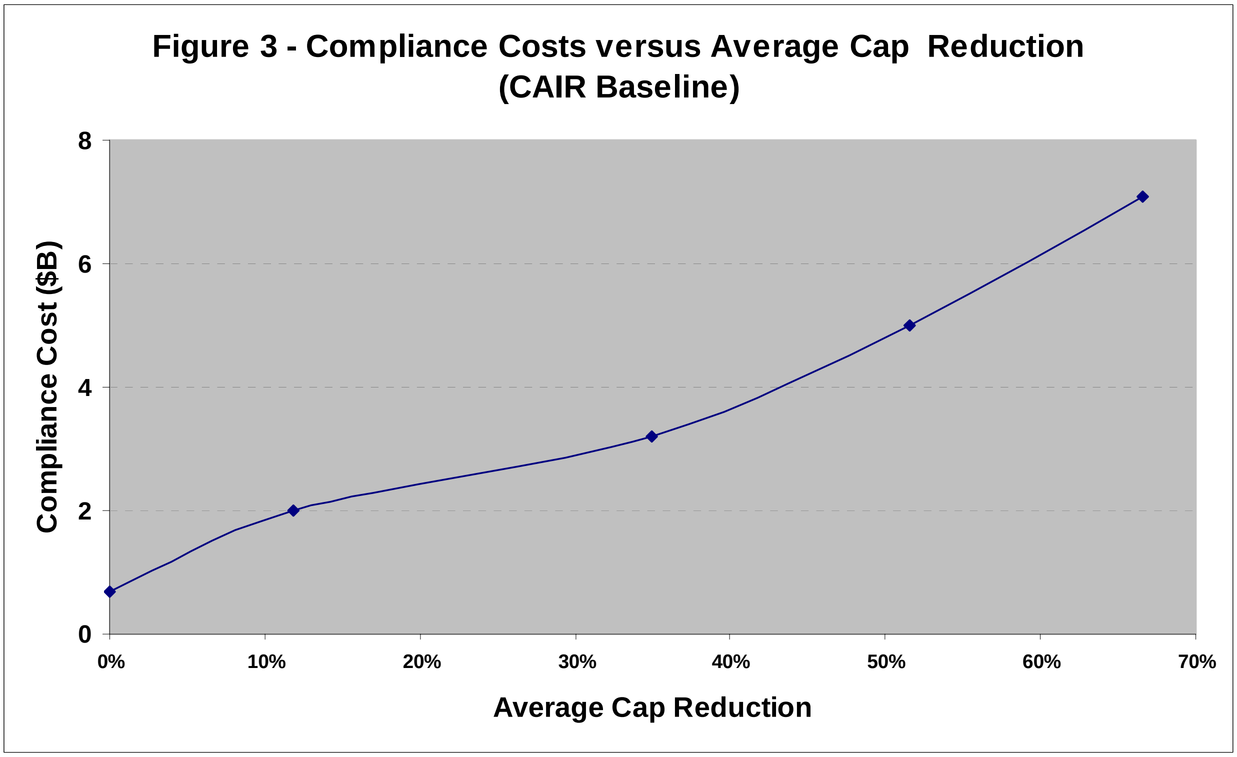
Table 10 illustrates as the regional NOx and SO2 budgets and the annualized compliance costs for each scenario.

TABLE 10

REGIONAL SO2 AND NOX BUDGETS AND ANNUALIZED COMPLIANCE COSTS

Scenario	NOx Budget	SO2 Budget	Compliance Costs
CAIR	399,895	1,046,659	0.7B
IM1	376,037	860,956	2.0B
IM2	300,830	573,971	3.2B
EGU1	250,069	358,732	5.0B
EGU2	175,484	239,154	7.1B

As demonstrated from the above table as regional NOx and SO2 budgets/caps decrease the level of compliance costs increase dramatically. For electric generators in the five states, the annualized compliance costs to meet the EGU2 NOx and SO2 emission caps is ten times greater than meeting the Phase I CAIR NOx and SO2 caps. This cost impact can be further illustrated by Figure 3 that shows the effect of increasing average cap reduction percentage from CAIR significantly increases the annualized compliance costs.



VII. CONCLUSIONS

This comparative evaluation illustrates, as regulatory scenarios become more stringent, not only do electric generating compliance costs increase significantly, but there are serious implications in meeting very extreme emission targets and timetables. However, there are major policy issues that arise in meeting the targets and timetables of IM1 & IM2 and EGU1 & EGU2, and they are:

- Compliance with the IM1 and IM2 SO2 cap could place between 4.4 GW and 8.5 GW of region's coal-fired capacity "at risk," respectively;
- The application of very aggressive control assumptions by electric generators in the five states indicate they are unable to achieve EGU1 and EGU2 SO2 emission caps and EGU2 NOx cap in 2013;
- Meeting the EGU1 and EGU2 SO2 emission caps could result in the retirement of 10.6 GW and 34.9 GW of the region's existing coal-fire capacity;
- Eventual compliance with EGU1 and EGU2, the region's electrical generators would incur annualized compliance costs that are ten times greater than they would spend on CAIR; and,
- Compliance with EGU1 and EGU2 would displace between 42.6 and 47.8 million tons of Indiana, Illinois and Ohio coal with natural gas and PRB coal.

APPENDIX A

METHODOLOGY TO DETERMINE REGIONAL NOX AND SO2 BUDGETS

The purpose of this appendix is present a brief discussion on the methods and data utilized in determining the NOx and SO2 Budgets for IM1 & IM2 and EGU1 & EGU2 within the five states that comprised the MRPO.

NOx BUDGET

As mentioned earlier, the state budgets for NOx followed the CAIR allocation process; therefore, the first step was to determine the 5-State or regional cap for NOx. This initial step involved identifying the highest annual Btu level for all Acid Units in the 5-State Region between the years 1999 to 2002. As shown in Table 1, the highest annual Btu level was selected for each state and summed to achieve a regional total.

Table 1: State Btu for Acid Rain Units: 1999 - 2002 (mmbtu)

State	Fuel	1999 HI	2000 HI	2001 HI	2002 HI	HI BTU
IL	All	895,604,720	941,011,079	933,356,252	**1,007,079,911**	**1,007,079,911**
IL	Coal	850,004,672	898,806,593	880,458,753	931,056,500	
IL	Gas	42,644,245	39,816,423	49,687,377	73,830,909	
IL	Oil	2,955,803	2,388,063	3,210,122	2,192,502	
IN	All	1,350,676,762	**1,356,985,881**	1,282,844,559	1,257,543,806	**1,356,985,881**
IN	Coal	1,336,763,815	1,343,227,931	1,263,538,709	1,231,380,954	
IN	Gas	13,133,977	13,433,549	19,229,684	26,128,241	
IN	Oil	778,970	324,401	76,166	34,611	
MI	All	**803,099,194**	769,855,356	757,546,178	758,577,254	**803,099,194**
MI	Coal	747,647,562	720,117,465	706,851,598	700,052,101	
MI	Gas	28,018,280	28,985,755	30,948,168	43,631,253	
MI	Oil	27,433,352	20,752,136	19,746,412	14,893,900	
OH	All	1,308,156,997	**1,333,059,526**	1,254,434,234	1,322,094,444	**1,333,059,526**
OH	Coal	1,298,547,674	1,325,041,112	1,243,753,980	1,301,135,141	
OH	Gas	9,609,323	8,018,414	10,680,254	20,959,303	
WI	All	508,092,322	**513,589,824**	498,207,479	483,187,294	**513,589,824**
WI	Coal	485,877,284	491,514,817	477,269,081	458,564,604	
WI	Gas	19,343,277	19,214,401	17,848,478	21,649,329	
WI	Wood	2,871,761	2,860,606	3,089,920	2,973,361	
						5,013,814,336

The regional Btu level (5.01 quadrillion Btu) allowed for the determination of the regional NOx budget for IM1 & IM2 and EGU1 & EGU2 by simple multiplying each scenarios proposed NOx emission rate times the regional Btu level. Table 2 illustrates the regional NOx budgets (caps) calculated for each of the IM and EGU scenarios.

Table 2: Regional NOx Budgets by Scenario
(tons)

Scenario	NOx Budget
IM1	376,036
IM2	300,829
EGU1	250,691
EGU2	175,484

The next step was an allocation of the regional budget to each of the five states that composed the 5-State Region. The initial task of this step involved determining the average of the 1999 – 2002 Btu (in mmbtu) for Acid Rain and Non-Acid Rain by fuel for each of the five states. These state averages by fuel were adjusted by the CAIR fuel adjustment factors (coal - 1.0, oil - 0.6 and gas – 0.4) and summed to achieve a total adjusted Btu level for each state, as shown in Table 3.

Table 3 – State NOx Budgets for IM and EGU Scenarios
(tons)

State Total	Fuel	ADJ BTU	Total ADJ BTU	State Btu Proportion	IM1	IM2	EGU1	EGU2
IL	**All**		**912,761,475**	**0.1907**	**71,699**	**57,360**	**47,681**	**33,460**
IL	Coal	890,081,630						
IL	Gas	21,018,254						
IL	Oil	1,661,591						
IN	**All**		**1,304,365,090**	**0.2725**	**102,461**	**81,969**	**68,138**	**47,815**
IN	Coal	1,294,854,369						
IN	Gas	9,251,452						
IN	Oil	259,269						
MI	**All**		**781,941,042**	**0.1633**	**61,423**	**49,139**	**40,847**	**28,664**
MI	Coal	724,205,284						
MI	Gas	45,233,759						
MI	Oil	12,501,998						
OH	**All**		**1,301,161,363**	**0.2718**	**102,209**	**81,767**	**67,970**	**47,698**
OH	Coal	1,295,963,448						
OH	Gas	5,066,198						
OH	Oil	131,717						
WI	**All**		**486,859,619**	**0.1017**	**38,244**	**30,595**	**25,433**	**17,847**
WI	Coal	478,306,447						
WI	Gas	8,304,634						
WI	Oil	248,538						
WI	**Wood**	0						
			4,787,088,589	**1.0000**	**376,037**	**300,830**	**250,069**	**175,484**

The final task is the allocation of the regional NOx budget to individual states, which is accomplished by multiplying a state's Btu proportion by the regional NOx budget (Table 2) to yield state budget or caps for IM1 & IM2 and EGU1 & EGU2. All heat input data is from U.S. EPA's Technical Support Data used in the final CAIR.

SO2 BUDGET

Initially, the SO2 state budgets for IM1 & IM2 and EGU1 & EGU2 attempted to follow the CAIR allocation process, which is based upon Title IV – Phase II (2010) allocations. However, the stringency of the proposed SO2 emission rates for both the IM and EGU scenarios, coupled with the 1985 – 1987 baseline used for Title IV SO2 allocations, made the caps impossible to achieve in the IM scenarios. Therefore, an alternative allocation was used based upon the average heat input for the years 2000 – 2004 from EPA's CEM data for Acid Rain units. As shown in Table 4, each scenario's SO2 emission rate is multiplied by a state's average heat input (mmbtu) to yield a state's IM or EGU budget/cap.

Table 4 – State SO2 Budgets for IM and EGU Scenarios
(tons)

State	2000 - 04 Ave Btus	IM1	IM2	EGU1	EGU2
IL	985,638,162	177,415	118,277	73,923	49,282
IN	1,241,853,612	223,534	149,022	93,139	62,093
MI	750,342,264	135,062	90,041	56,276	37,517
OH	1,303,918,125	234,705	156,470	97,794	65,196
WI	501,335,732	90,240	60,160	37,600	25,067
REGION	4,783,087,895	860,956	573,971	358,732	239,154
SO2 ER		0.36	0.24	0.15	0.10

APPENDIX B

SUMMARY OF ASSUMPTIONS DEFINING THE FEASIBILITY AND COST OF ENVIRONMENTAL CONTROLS FOR ANALYSIS OF THE MIDWEST RPO MANDATES

INTRODUCTION

Appendix B to this report presents additional detail regarding the assumptions defining the feasibility and cost of environmental control technology. Appendix B serves as the basis of descriptive material that was presented in the final report.

This work consisted of simulating industry decision-making in defining the least cost compliance plan. With approximately 275 units to consider, a limited number of technical options were considered, so as to bound the nature of the problem. However, the limited options represent in general the type of equipment and costs encountered.

As an example, it is well known that many choices exist from which to select flue gas desulfurization technology. A recent review has overviewed the features of different categories of control equipment, identifying the characteristics unique to each (EPA, 2000). However, for the purpose of this analysis, only one option – wet conventional limestone-based FGD – was evaluated. This assumption should not be interpreted to suggest that only this technology is viable for power producers within the Midwest RPO; in fact a broad range of equipment should be considered. However, given that most options exhibit similar incurred cost after levelizing both capital and operating cost, selecting one approach is essential to bounding the problem, and is not believed critical to the outcome.

Similarly, with respect to NOx, two control options were considered – selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). The use of SNCR was included to provide an alternative option to capital-intensive, high NOx removal SCR. In reality, there are a number of technologies that exhibit the low capital cost, low-moderate NOx removal typical of SNCR. These include both natural gas and coal reburn, and several variants of these processes (e.g. NOxStar). In the context of the present analysis, we submit it is important to offer a feasible alternative to SCR – thus SNCR is considered a "surrogate" for the numerous alternatives. Accordingly, although the site-specific decisions at any one plant may differ from those predicted by this study, the number of installed SCR options versus low capital cost alternatives is anticipated to be correct.

The specific control equipment used in the analysis, and a description of assumed performance and cost, is presented in the following sections for control of SO_2 and NOx.

FLUE GAS DESULFURIZATION

Selecting the optimal process for any given site requires a detailed engineering analysis, beyond the scope of the present study. Accordingly, conventional limestone, forced oxidized flue gas desulfurization was selected as a "surrogate" of the candidates.

The SO_2 removal efficiency was assumed to depend on the coal sulfur content. Specifically, the "baseline" design specified an SO_2 removal efficiency of 90 and 95% was assumed achievable for application to PRB and medium-high sulfur coals, respectively. In addition to this "baseline" design, a "high performance" option was included that allowed extracting up to 97% SO2 removal, for a modest capital and operating cost premium.

The main source of cost information for conventional limestone-based FGD is an analysis prepared for Cinergy Corporation in planning future FGD capacity. This analysis contains data from existing units, and projections based on detailed engineering studies of FGD equipment. These estimates, shown in Figure 1, generally exceed the projections that can be derived using the EPA-issued cost spreadsheet "CUECost" (Keeth, 1999).

Regarding operating costs, Fixed O&M was assumed to be equivalent to 5% of the capital requirement, incurred annually. Variable O&M costs were selected from Table 1, developed from CUECost, which summarizes variable O&M for the three categories of coal. The subject Midwest RPO analysis invoked these variable costs from a lookup table, pending definition of the coal type.

Table 1 summarizes the SO2 removal efficiency assumed, by coal composition, and the operating penalty in terms of power consumption as a percent of generating capacity.

Table 1 - Wet FGD Variable O&M (mills/kWh)

Coal Type (by Sulfur content)	Variable O&M (mills/kWh)	SO2 Removal: Baseline Design	Capacity Penalty (% of capacity)[5]	Energy Penalty (% of capacity)
PRB	0.69	90	1.40	1.5
Medium Sulfur	1.05	95	1.7	1.5
High Sulfur	1.89	95	2	1.5

For new FGD equipment, a high performance option was defined that extracted higher SO2 removal for a premium in capital and operating cost. The baseline design targets of 90 and 95% could be increased to 94 and 98% for an additional $2/kW capital, and 0.20 to 0.25 mills/kWh increase. Table 2 summarizes these options.

[5] Derived from Sargent & Lundy, 2003

Figure 1 - FGD Capital Cost Estimates

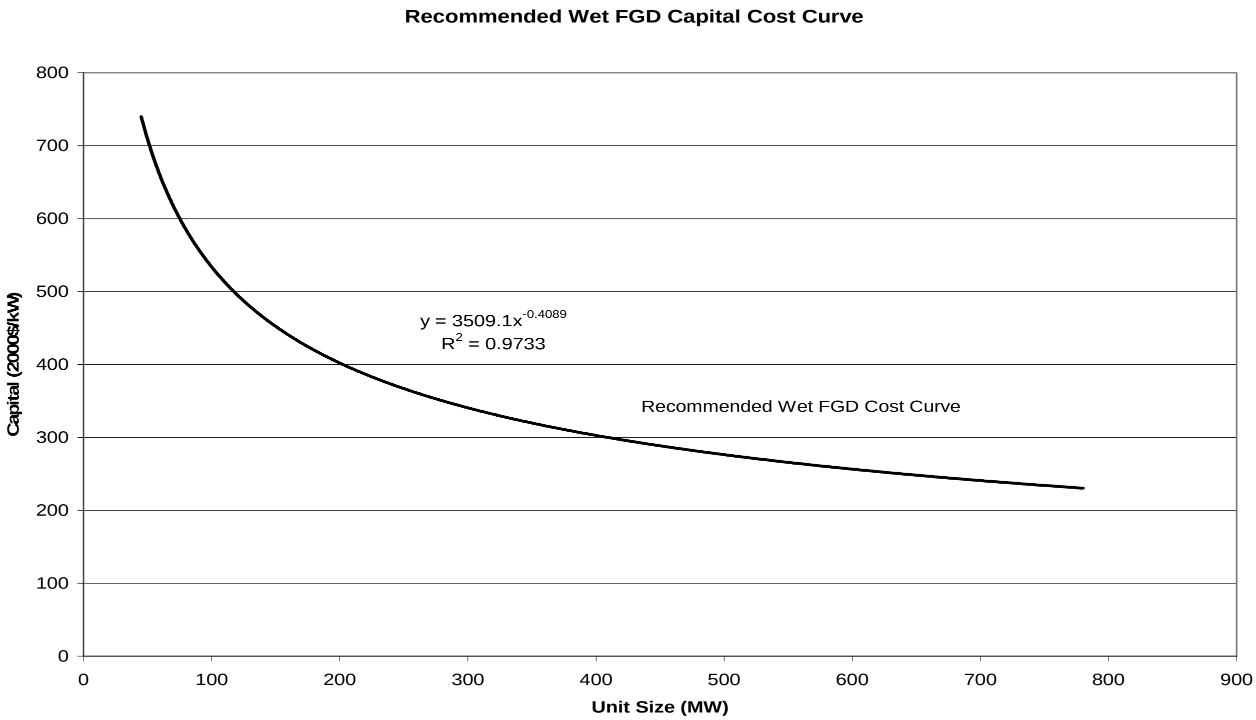


Table 2 - New FGD High Performance SO2 Removal Option

SO2 Removal Increment	SO2 Removal,%	Capital Adder ($/kW)	Var O&M (mills/kWh)
PRB	To 94%	2	0.20
Med-High S coal	To 98%	2	0.25

There are numerous existing FGD processes in operation by Midwestern power producers, and the prospect of upgrading existing equipment to improve performance has been discussed by numerous investigators such as Froelich (1995), Maller (2003), and Doptoka (2003). As these investigators note, the technical feasibility of FGD upgrade is site-specific; depending on the nature of the site or the composition of the coal, only negligible improvement to SO2 removal could be realized. However, for the purpose of this study, it was assumed that upgrade was feasible; it is important to recognize this is an assumption that was not based on specific analysis.

Table 3 summarizes the assumptions defining the potential ability to upgrade existing FGD process equipment. In the content of this study, it is assumed the performance of both venturi-type equipment and conventional open spray towers can be improved.

- All FGD technologies are assumed to be able to deliver a minimum of 93% SO2 removal,
- A capital charge is incurred for a detailed engineering study, including physical cold flow model, upgrade to reagent slurry pumps, and perhaps wall rings to reduce leakage,

- An operating cost increase is incurred, to provide for both greater reagent quantity, and the use of a buffering additive.

Table 3 - FGD Upgrade Assumptions

SO2 Removal Increment	70->93	80→93
Capital ($/kW)	15	10
Operating cost (mills/kwh)	0.25	0.15

The analysis conducted for Midwestern power producers used this information to evaluate the cost of conventional FGD for various coals, and the prospect of deriving additional SO2 reductions by upgrading process equipment.

NITROGEN OXIDES

There is a wide variety of NOx control options that can be applied at a coal-fired power station, considering technology both presently available and evolving. For the purpose of the present analysis, the post-combustion options considered were limited to SCR, and a lower capital cost alternative, SNCR. As stated in the Introduction, the selection of a limited number of options should not be interpreted as an endorsement of any particular technology; specifically SNCR is not the sole alternative to SCR. Rather, SNCR should be considered a surrogate of a variety of lower capital cost, lower NOx removing options.

Combustion Controls

Prior to being considered for retrofit of post-combustion controls, each unit was evaluated to determine if additional NOx removal by combustion controls was appropriate. Table 4 describes the performance and cost of both low NOx burners (LNB) and over-fire air (OFA). For each unit, the reported 2003 NOx emissions were compared to the NOx rates in Table 4, which are considered to represent the NOx emissions of a unit equipped with state-of-art combustion controls. In cases where the reported NOx emissions exceed these rates, the appropriate combustion modifications were assumed to be retrofit.

Table 4 - Summary of Combustion Control Assumptions

Boiler Type	LNB	LNB+OFA	LNB	LNB+OFA	LNB	LNB+OFA	LNB	LNB+OFA
	High S bit		*Low-Med S bit; Low S East.*		*Low S West*		*PRB*	
tangential	0.4	0.38	0.38	0.36	0.35	0.32	0.22	0.18
front	0.45	0.43	0.43	0.4	0.37	0.32	0.3	0.25
opposed	0.45	0.43	0.43	0.4	0.37	0.32	0.3	0.25
cell	0.68	0.62	0.62	0.57	0.55	0.5	0.48	0.45
wet-bottom	0.86	N/A	0.8	N/A	N/A	0.65	N/A	0.5
cyclone	N/A	1.5	N/A	0.95	N/A	0.65	N/A	0.55

The combustion control technologies described in Table 4 were applied to units according to the following criteria:

- LNB were applied to units greater than 20 MW that were not previously equipped with any combustion controls,
- Units with LNB adopted OFA, for a capacity factor > 25% and generating capacity > 100 MW
- post-1972 NSPS units were assumed to derive an additional 0.02 lbs/MBtu reduction, beyond that defined feasible in Table 4

The cost for LNB and OFA equipment was derived as follows:

- LNB costs were $7/kW for a 500 MW unit, scaled from 100-600 MW capacity with a 2/3 power-law
- OFA costs were $10/kW for a 500 MW unit, scaled from 100-600 MW with a 2/3 power law
- Cyclone boilers adopted OFA alone at $5/kW

In general, almost all units applied some type of combustion control prior to considering post-combustion strategies.

SNCR

Table 5 presents the assumptions defining the performance and cost for SNCR NOx control. As shown, both the NOx removal efficiency achievable, and capital/operating cost vary as function of initial NOx rate. The data in Table 5, particularly for larger units, is based on recent demonstrations on large capacity units (Hines, 2003). The SNCR cost data is based on public references, and is consistent (although not exactly the same) as derived in CUECost.

SCR

SCR capital and operating cost are presented in Tables 5 and Figure 2. Table 5 presents fixed and variable operating cost, as a function of boiler type, and initial NOx rate. Figure 2 presents the derived relationship between SCR capital cost and generating capacity. Basic process design factors such as boiler NOx rate entering the SCR process and the design NOx removal efficiency are well-known to influence the catalyst volume and replacement rate. However, the cost impact of these factors can be super-ceded by site – specific factors that affect the amount of labor required for retrofit; according only generating capacity is used to express capital cost in this relationship.

Figure 2 depicts an inferred relationship between SCR capital cost and generating capacity. This relationship was derived based on a survey of actual SCR costs incurred by domestic U.S. power producers (Cichanowicz, 2004). For the purposes of this study, the SCR capital cost of any given unit is determined by the value derived from the correlation in Figure 3.

Table 5 - SNCR NOx Removal, Operating Cost

Capacity (MW)	**Burner Firing Type** t-tangential; f- front-fired; o - opposed fired	**Initial Boiler NOx** (lbs/MBtu)	**Conventional SNCR** SNCR ($/kW)	SNCR O&M ($/MWh)	NOx Removal (%)
>500	t-f-o	0.20-0.30	10.0	0.35	25
	t-f-o	0.31-0.40	"	0.48	25
	t-f-o	0.40-0.50	"	0.58	25
	t-f-o	>0.50	"	0.63	25
	cell	<0.65	16	0.74	28
	"	>0.65	16	0.89	28
	cyclone/wet-bottom	<0.86	16	0.95	30
	"	>0.86	16	1.22	30
400-500	t-f-o	0.20-0.30	11	0.35	25
	t-f-o	0.31-0.40	"	0.48	25
	t-f-o	0.40-0.50	"	0.58	25
	t-f-o	>0.50	"	0.63	25
	cell	<0.65	13	0.74	28
	"	>0.65	13	0.89	28
	cyclone/wet-bottom	<0.86	13	0.95	30
		>0.86	13	1.22	30
300-400	t-f-o	0.20-0.30	13	0.35	27
	t-f-o	0.31-0.40	"	0.48	27
	t-f-o	0.40-0.50	"	0.58	27
	t-f-o	>0.50	"	0.63	27
	cell	<0.65	15	0.74	30
	"	>0.65	15	0.89	30
	cyclone/wet-bottom	<0.86	15	0.95	32
	"	>0.86	15	1.22	32
200-300	t-f-o	0.30-0.40	16	0.35	30
	t-f-o	0.41-0.50	"	0.48	30
	t-f-o	>0.50	"	0.58	30
			"	0.63	30
	cell	<0.65	18	0.74	
	"	>0.65	18	0.89	33
	cyclone/wet-bottom	<0.86	18	0.95	33
	"	>0.86	18	1.22	33
126-200	t-f-o	<0.40	22	0.35	33
	t-f-o	0.40-0.50	"	0.48	33
	t-f-o	>0.50	"	0.58	33
	cell	<0.65	24	0.74	36
	"	>0.65	24	0.89	36
	cyclone/wet-bottom	<0.86	24	0.95	36
	"	>0.86	24	1.22	36
75-125	t-f-o	<0.40	29	0.35	36
	t-f-o	0.40-0.50	"	0.48	36
	t-f-o	>0.50	"	0.58	36
	cell	all	"	0.9	40
	cyclone/wet-bottom	all	"	0.9	40
20-74	all		35	0.9	45

Table 6 presents SCR operating and maintenance costs as a function of boiler inlet NOx rate, showing both variable and fixed O&M.

Table 6 - Summary of SCR Variable, Fixed Operating and Maintenance Costs

Note: NOx removal will be either 90%, or limited to the NOx emissions rates shown in the below table

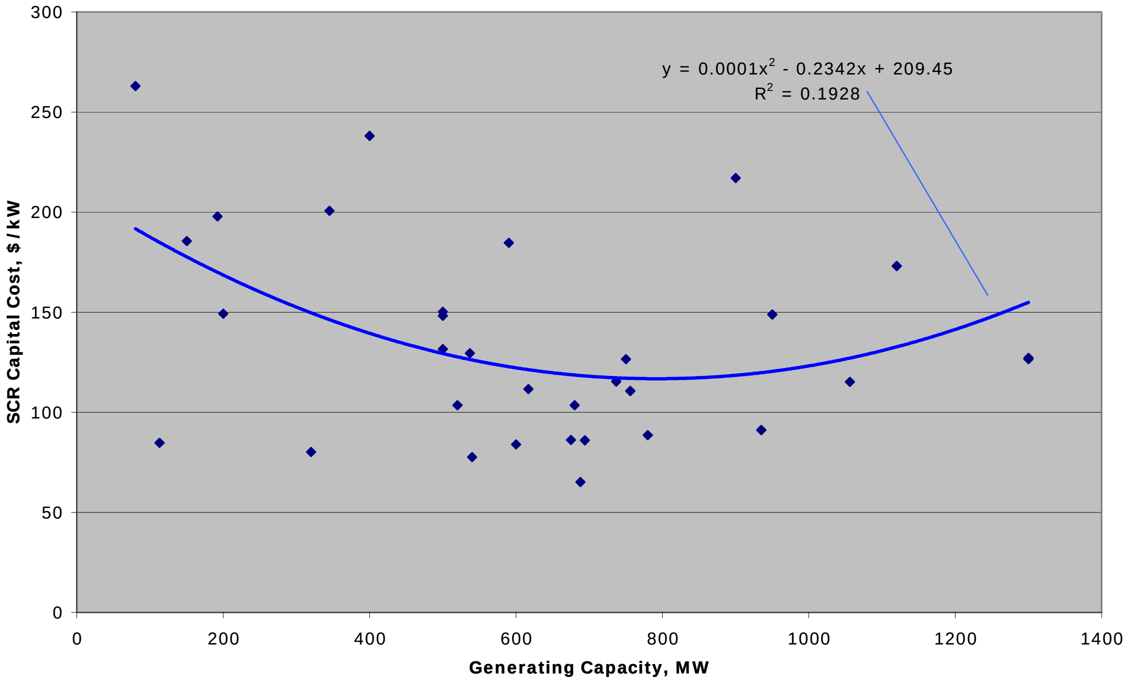
Initial Boiler NOx (lbs/MBtu)	SCR O&M Variable ($/MWh)	SCR Fixed O&M (% of Capital /yr)
0.3	0.59	0.75
0.4	0.63	0.75
0.5	0.75	0.75
0.6	0.78	0.75
0.7	0.91	0.75
0.8	1.05	0.75

NOx Outlet Rates Achievable

Coal Type	NOx Out
PRB	0.045
Sub (<1.2%)	0.05
1.2-2.5	0.06
high S >2.5	0.07

The SCR long-term continuous NOx removal efficiency was assumed to be 90 percent; however, NOx emission rate floors were established based upon coal rank. These floors, which determine the minimum a final SCR controlled level, are shown on the right side of Table 6. These floors are 0.07 lbs/MBtu MBtu for low (<1.2%) sulfur sub-bituminous coal, and 0.045 lbs/MBtu for PRB. It is important to note these NOx targets are for annual averaging periods; shorter averaging periods will likely be characterized by higher SO2 emission rates. For example, a 30 day NOx emissions average for high sulfur bituminous coal could be 0.08 lbs/MBtu.

Figure 3. SCR Capital Cost vs. Capacity (w/Engineering/AFDC)



COAL SWITCHING

One control strategy considered in this analysis was the potential to switch coals, from medium-high sulfur to lower sulfur content, including coals from the PRB. This section summarizes the two factors used in the fuel switching analysis; the capital cost for the plant modifications to accommodate the switch, and the cost of the alternative coal.

Two types of fuel switching were considered as a part of evaluating SO2 compliance options, which considered differential coal prices. These are summarized as follows:

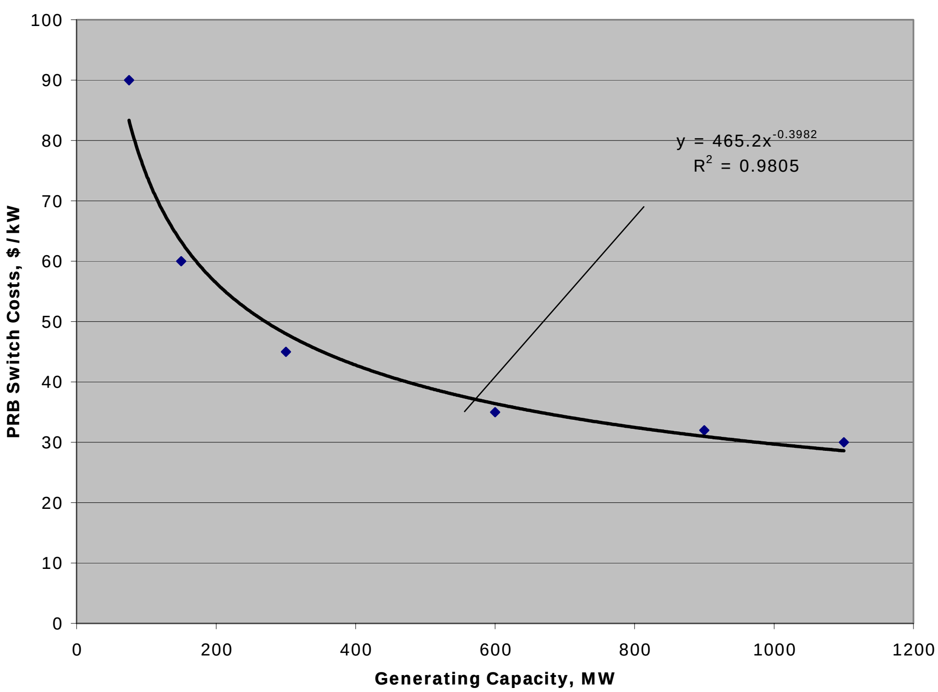
- Switching from a higher sulfur bituminous coal to a low sulfur sub-bituminous (PRB) coal, to avoid FGD, and
- Determining the optimal combination of FGD and coal type, by considering both FGD O&M cost for each of sub-bituminous (PRB), and medium or higher sulfur bituminous coal.

Coal Switch Capital Costs

The broad availability of PRB has prompted many operators to consider switching to PRB and other low sulfur coals. The use of PRB coal will impacts almost all aspects of operating a power plant, and is contemplated only after detailed engineering studies defining the impacts (Power, 2003). A coal switch to PRB from either medium or high sulfur coal usually requires capital investment to maintain thermal performance and minimize capacity de-rate. Several operators that are contemplating or have already switched to PRB coal provided input as to capital cost estimates for PRB conversion.

Of the coal switch options considered in this study, only a switch to PRB required capital investment. Figure 4 presents the relationship between capital cost to accommodate PRB coal and generating capacity, as determined from the survey of operators.

Figure 4. PRB Switch Costs vs. Capacity



Alternative Coal Costs

This analysis considered three sources of coal – PRB, medium sulfur from the Eastern Interior region, and high sulfur from the Eastern interior region. Table 7 summarizes the heating value and sulfur content of the coals that were used to represent these three different classes of options. Table 8 presents the cost of each coal, expressed on a 2003 dollar basis, over the time period of the analysis. The coal prices in Table 8 were derived from EIA's *Annual Energy Outlook 2005 (AEO 2005)*.

Table 7 - Characteristics Of Coals From Alternative Sources

Coal Characteristic	PRB	Medium sulfur	High Sulfur
Sulfur content, %	0.30	1.2	3.0
Heating Value (Btu/lb)	8,700	10,518	11,082

Table 8 - Delivered Coal Prices: 2010 - 2015

Census Region	Supply Region	Supply Region States	SO2 ER	2010	2011	2012	2013	2014	2015
East North Central	CA	S.WV,VA,E.KY,N.TN	Low (1.2 or less)	1.41	1.39	1.37	1.38	1.39	1.40
East North Central	CA	S.WV,VA,E.KY,N.TN	Medium (>1.2 - 3.33)	1.36	1.47	1.43	1.45	1.44	1.30
East North Central	EI	W.KY,IL,IN,MS	High (>3.33)	1.13	1.12	1.12	1.11	1.12	1.13
East North Central	NA	PA,OH,MD,N.WV	High (>3.33)	1.08	1.08	1.12	1.12	1.13	1.13
East North Central	PRB WY	WY Powder River Basin	Low (1.2 or less)	1.13	1.13	1.13	1.13	1.13	1.13

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APPENDIX C

REPLACEMENT CAPACITY POWER COSTS, STATE LEVEL COMPLIANCE COSTS AND LOCAL COAL DISPLACEMENT

The focus of this appendix briefly discusses the methodology to determine the replacement power costs and local coal displacement. It also presents IM and EGU compliance costs by state.

REPLACEMENT POWER COSTS

As mentioned in the text, replacement power for those units that would be retired under EGU1 and EGU2 would be supplied by three sources and they are: (i) increased operation of existing (2013) gas-fired combined cycle capacity in ECAR, MAIN and MAPP; (ii) imported power from surrounding NERC regions; and, (iii) the construction of new gas-fired combined cycle capacity in the affected NERC regions. It was assumed the replacement power or electrical demand would be initially supplied by existing capacity and then followed by imported power. Only after, these two components achieved maximum capability would new units be constructed.

The table below illustrates the level of nameplate capacity and generation that would have to be replaced under EGU1 and EGU2 within the five states for year 2013. The data is presented by NERC region because some states contain two NERC regions and any electricity to be supplied to these five states would have to be supplied through a grid based upon a NERC region.

Table 1 – Replacement Power Requirement: 2013

EGU1	MW	Generation (kWh)
ECAR	7,867.5	44,959,822,101
MAIN	2,680.3	15,271,658,743
MAPP	82.4	433,094,400
	10,630.2	60,664,575,244
EGU2		
ECAR	20,744	120,170,934,587
MAIN	13,578.6	72,548,970,003
MAPP	586	353,9571,115
	34,908.6	196,259,475,705

Existing Gas-Fired Combined Cycle Capacity

The first component of replacing this lost power was increasing the operation of existing gas-fired combined cycle capacity. In 2013, there was a projected availability of 3,785 MW in ECAR and 2,167 MW in MAIN of exiting combined-cycle capacity that could be used to supply additional generation, as shown in Table 2. It as assumed the replacement power for MAPP could be entirely achieved through imports; therefore, no existing generation would come from existing combined cycle capacity.

Table 2 – Replacement Power from Existing Combined Cycle: 2013

	Available CC Capacity (MW)	Generation Supplied (kWh)	Cost of Incremental Generation (2003$)
EGU1			
ECAR	3,485	30,532,279,200	1,275,027,979
MAIN	2,167	15,271,658,743	637,744,469
MAPP			
Total Cost			1,912,772,448
EGU2			
ECAR	3,485	30,532,279,200	1,275,027,979
MAIN	2,167	18,979,328,400	792,576,754
MAPP			
Total Cost			2,067,604,733

The assumed incremental cost for fuel (natural gas) in 2013 is $5.55/mmbtu and variable O&M costs are 1.8 mills/kWh. The future gas price is based upon a comparison of natural gas price forecasts, while the variable O&M is based upon EIA's *AEO2005* performance costs of new generating technologies.

Imported Power

The second component of replacing power would come from importing power from neighboring NERC regions, which in this case would be primarily from MAAC, SERC and SPP. Based upon data from EIA and NERC on regional transmission capability and 2013 imports into ECAR, MAIN and MAPP, the table below illustrates the assumed 2013 import capability into ECAR, MAIN and MAPP.

Table 3 – Region to Region Transmission Capability: 2013
(MW)

Import Region	Import Capability and Export Regions
ECAR	8,233 from MAAC and SERC
MAIN	3,386 from SERC and SPP
MAPP	3,300 from SERC, SPP, NWP and RA

Table 4 indicates the level of power imported from neighboring regions and the cost of the imported power.

Table 4 – Replacement Power from Imported Power: 2013

	Imported Capacity (MW)	Imported Generation (kWh)	Cost of Imported Power (2003$)
EGU1			
ECAR	1,646.98	14,427,542,901	591,529,259
MAIN	0	0	0
MAPP	49.44	433,094,400	16,457,587
Total Cost			607,986,846
EGU2			
ECAR	8,233	72,121,080,000	2,956,964,280
MAIN	3,386	29,661,360,000	1,127,131,680
MAPP	404.06	3,539,571,115	134,503,702
Total Cost			4,218,599,662

The cost of imported power was based upon the exporting region's 2013 generation costs (cents/kWh) that were estimated in *AEO2005*.

New Gas-Fired Combined Cycle Capacity

The final component of the replacement power equation is building new gas-fired combined cycle capacity. Only EGU2 required new gas-fired capacity to be constructed, EGU1 was able to meet its electrical demand through increased operation of existing combined cycle capacity and importing power from neighboring regions. Table 5 illustrates the level of replacement power that will be supplied by new natural gas-fired combined cycle capacity.

Table 5 – Replacement Power from New Gas-Fired Combine Cycle Capacity EGU2: 2013

EGU2	New Gas Capacity - Nameplate (MW)	New Gas-fired Generation (kWh)	Total Cost of New Gas-fired Generation (2003$)
ECAR	3,926.73	17,517,575,387	957,236,781
MAIN	5,359.27	23,908,281,603	1,306,452,863
MAPP	0	0	0
Total Cost			2,263,689,644

The assumptions for capital and fixed & variable O&M costs for the new capacity were from EIA's *AEO2005* performance costs of new generating technologies. The 2013 natural gas price was the same $5.55/mmbtu used to determine the incremental cost for existing gas capacity.

It should be noted the previous discussed calculations do not take into account the production and fuel costs of the coal-fired units they are replacing. A final step of this methodology was to net out these costs, which presents a more accurate incremental (or net) compliance costs of EGU1 and EGU2. The table below illustrates both the gross and net replacement costs for EGU1 and EGU2, with the net cost value being the more accurate compliance value used in computing the total compliance costs for EGU1 and EGU2.

Table 6 – Gross and Net Replacement Power Costs
(2003$)

	EGU1(2013)	EGU2(2013)
Cost	Replacement Power	Replacement Power
Gross	2,520,734,431	8,549,847,800
Net	1,359,639,479	4,916,840,764

STATE LEVEL COMPLIANCE COSTS FOR IM AND EGU SCENARIOS

The compliance costs presented in the main text illustrate costs at the regional or five state levels. The purpose of this section is to illustrate these same compliance costs, but present them at the state level. Table 7 illustrates the annualized compliance costs by state for IM1 & IM2 and EGU1 & EGU2.

Table 7 – Annualized Compliance Costs by State
(2003$)

State	IM1(2012)	IM2(2012)	EGU1(2013)	EGU2(2013)
IL	141,908,552	645,616,218	1,048,153,282	1,660,341,178
IN	622,442,301	873,103,743	1,487,854,525	1,949,303,522
MI	353,145,306	584,606,536	695,753,911	1,111,678,216
OH	713,441,471	773,016,589	1,417,768,180	1,640,383,855
WI	204,150,547	302,702,955	345,107,623	711,341,661
Total	2,035,088,176	3,179,046,041	4,994,637,521	7,073,048,432

Table 8 presents breakouts of the EGU1 and EGU2 annualized compliance costs between the net replacement power costs (see Table 6) and SO2 and NOx control technology costs by state.

Table 8 – Compliance Costs to Meet EGU1 and EGU2
(2003$)

	EGU1(2013)			EGU2(2013)		
State	Rep. Power	Technology	Total	Rep. Power	Technology	Total
IL	280,017,300	768,135,982	1,048,153,282	1,255,093,744	405,247,434	1,660,341,178
IN	363,307,377	1,124,547,148	1,487,854,525	1,327,599,129	621,704,393	1,949,303,522
MI	226,643,242	469,110,669	695,753,911	871,410,559	240,267,657	1,111,678,216
OH	446,974,380	970,793,800	1,417,768,180	891,707,099	748,676,756	1,640,383,855
WI	42,697,180	302,410,443	345,107,623	571,030,233	140,311,428	711,341,661
Total	1,359,639,479	3,634,998,042	4,994,637,521	4,916,840,764	2,156,207,668	7,073,048,432

The table above illustrates a shift from control technology to replacement power as compliance becomes more difficult and more coal-fired capacity would have to be retired.

LOCAL COAL DISPLACEMENT

The focus of this analysis was to determine level of coal that is mined in Illinois, Indiana and Ohio that could be displaced as a result of compliance with either EGU1 or EGU2. There are two types of compliance decisions that can impact local coal: (i) retirement of existing coal units; and, (ii) fuel switching existing/retrofitted FGDs from high sulfur coal to PRB coal.

The determination those units that would receive local coal in 2013 was based upon data contained in the *EEMS* Data Base and 2004 reported data from EIA Form 423 and FERC Form 423. The EGU1 and EGU2 model simulations identified those units that could be retired or fuel switched and had these units' 2013 Btus computed. Unit Btus were converted to tons of local coal that could be displaced by an average coal heat content of Illinois (11,655 Btu/lb.), Indiana (11,395 Btu/lb.) and Ohio (12,143 Btu/lb.) coals. The table below illustrates the level of local coal that would be displaced due to compliance with EGU1 and EGU2 in 2013.

Table 9 – Displacement of Illinois, Indiana and Coal: 2013
(tons)

	EGU1			EGU2		
COAL ORIGIN	RETIREMENT	FUEL SWITCH	TOTAL	RETIREMENT	FUEL SWITCH	TOTAL
IL	190,004	5,650,655	5,840,658	4,340,854	2,454,984	6,795,838
IN	2,994,510	15,928,198	18,922,709	13,509,336	8,378,637	21,887,973
OH	3,828,853	14,018,409	17,847,263	5,400,843	13,690,660	19,091,502
TOTAL	7,013,367	35,597,262	42,610,630	23,251,033	24,524,281	47,775,313