2547

Hughes, Marjorie

From: Pacoal1@aol.com

Sent: Monday, August 21, 2006 11:01 AM

To: RegComments@state.pa.us

Subject: Proposed Amendments to 25 Pa. Code Chapter 123

Comments re: Proposed Amendments to 25 Pa. Code Chapter 123, Standards for Containment; Mercury, 36 Pa.B.3185, Saturday, June 24, 2006

Please find our comments attached.

George Ellis
PA Coal Association
212 N. Third St., Suite 102
Harrisburg, PA 17101

Phone: 717-233-7900
Fax: 717-231-7610
Email: pacoal1@aol.com

Pennsylvania Coal Association
212 North Third Street • Suite 102 • Harrisburg, PA 17101

(717) 233-7909
(717) 236-5901
FAX (717) 231-7610

August 21, 2006

RECEIVED
AUG 23 AM 11:53
INDEPENDENT REGULATORY
REVIEW COMMISSION

Environmental Quality Board
P.O. Box 8477
Harrisburg, PA 17105-8477

Re: Proposed Amendments to 25 Pa. Code Chapter 123, Standards for Containment; Mercury, 36 Pa.B.3185, Saturday, June 24, 2006

Ladies and Gentlemen:

Please accept the attached report as an extension of the comments provided by Frank Burke on behalf of the Pennsylvania Coal Association (PCA) at the EQB's public hearing in Pittsburgh on July 25, 2006, relating to the above-referenced proposed rulemaking.

The Report was prepared James Marchetti, J.Edward Cichanowicz and Michael Hein at the request of the Center for Energy and Economic Development, the Edison Electric Institute and PCA.

Its objectives were to:

- Evaluate the compliance costs to Pennsylvania generators of meeting the reduction targets specified in the proposed state regulation;

- Measure the incremental compliance costs between the proposed regulation and the corresponding federal mercury rule (CAMR), and

- Evaluate the "co-benefits" associated with compliance with the federal Clear Air Interstate Rule (CAIR).

Among the Report's findings are:

- The state proposal would increase the cumulative annualized compliance cost for Pennsylvania generators between 2009 and 2018 by $1.6 billion beyond the cost to comply with CAMR.

- At least 10 units (representing five coal power plants) in which DEP would "presume" to be in compliance under Sec. 123.206 by installing certain control technologies (e.g. scrubbers, SCRs), would still be required to install additional controls or take other actions to achieve the rule's plant emission limits.

- Under the proposed rule, the Commonwealth will be over (in violation) its CAMR State Budget beginning in 2018.

- The proposed rule could put 5,800 MW or 28 percent of the state's coal fired capacity "at-risk" of retirement. While the Report did not consider the potential impact that the closure of these units could have on electric reliability, its authors suggest that a separate study of this issue is warranted given the magnitude of potential plant closures.

- If this coal capacity is retired, the study estimates that the Commonwealth could lose 85 million tons of its coal production between 2010 and 2018.

PCA respectfully asks the Board to consider these findings, which buttress PCA's opposition to the proposal, when voting on the rulemaking.

Thank you for this additional opportunity to provide comments. Please call me if you have any questions.

Sincerely,

George Ellis

George Ellis
President, Pennsylvania Coal Association

Final Report

EVALUATION OF THE COMPLIANCE IMPLICATIONS TO PENNSYLVANIA ELECTRIC GENRATORS OF MEETING GOVERNOR RENDELL'S PROPOSED MERCURY RULE

Prepared for

Center for Energy and Economic Development, Inc.
Edison Electric Institute
&
Pennsylvania Coal Association

Prepared by
James Marchetti
J. Edward Cichanowicz
Michael Hein

August 2006

Executive Summary

On March 23, 2006, Governor Edward Rendell proposed a state-specific mercury reduction plan (PA Rule) that would require Pennsylvania coal-fired electric generating units (EGUs) to reduce mercury emissions significantly beyond the requirements of the U.S. Environmental Protection Agency's (EPA) Clean Air Mercury Rule (CAMR). Governor Rendell's plan would cut mercury emissions faster than CAMR, targeting a 90 percent mercury reduction by 2015. CAMR requires Pennsylvania electric generators to achieve an 86 percent reduction of mercury emissions in a two-phase, market-based program commencing in 2010.

This analysis evaluates the compliance costs to PA generators of meeting the reduction targets proposed in the PA Rule. It also measures the incremental compliance costs between CAMR and the PA Rule. To better understand mercury emissions attributed to PA generators, we also evaluated the "co-benefits" associated with compliance with EPA's Clean Air Interstate Rule (CAIR). Our study is based on two modeling simulations: (i) PA generator compliance related to meeting CAIR/CAMR; and, (ii) PA generator compliance related to meeting CAIR/PA Rule.

Briefly, the PA Rule requires EGUs to meet: (i) a percent reduction from input mercury in coal or an output-based emission standard; **and**, (ii) an annual emission limitation over two phases. Phase I begins in 2010 and extends through 2014, while Phase II extends from 2015 and beyond. The proposed rule prohibits trading and banking of mercury allowances, but does allow electric generators to utilize facility averaging for compliance. In addition, the proposed rule "presumes" that certain units equipped with flue gas scrubbers and other specified technologies are already in compliance and would not be required to deploy additional mercury control technologies to meet the provisions of (i) above; however, this presumption does not apply to part (ii). This means that additional controls could be required to meet the annual cap – and as a matter of fact many units in PA that install the presumptive technology may still be required to install additional controls or take other actions to reduce mercury emissions. Furthermore, this study shows that this rule places nearly 5,800 MW, or about 28%, of Pennsylvania's coal-fired capacity at risk of retirement. This study does not assess the impact on reliability of the electrical supply system or on consumers for replacement energy costs that could only come from more expensive oil and gas units for the retirement of this amount of capacity

Required Capital Investments Are Doubled

To meet the targets and timetables of EPA's CAIR/CAMR, PA generators would invest \$1.6 billion in SO2, NOx and mercury control technologies. Beginning in 2010, we estimate that mercury emissions by Pennsylvania generators would be reduced by 60 percent compared to their pre-CAIR/CAMR levels. However, under the proposed CAIR/PA Rule, capital investments in control technologies would reach almost \$3.3 billion to meet the PA Rule's more stringent emission control standards. Of this total, \$1.7 billion, or 53 percent, would be attributed to mercury control technologies required to comply with the PA mercury rule. This is approximately double the investment that PA generators would have to make under CAIR/CAMR.

CAPITAL INVESTMENTS FOR SO2, NOx AND MERCURY CONTROL TECHNOLOGIES: 2009 – 2018
(in billions of 2006 $)

Rules	SO2	NOx	Hg	Total
CAIR/CAMR	1.05	0.33	0.24	1.62
CAIR/PA Rule	1.22	0.33	1.74	3.29
Differential Cost	0.17	0	1.50	1.67

$1.6 Billion Cumulative Increase in Generation Costs

The cumulative annualized compliance costs for PA generators between 2009 and 2018 under CAIR/CAMR are projected to be $4.9 billion, as shown below.[1] However, under a CAIR/PA Rule regulatory regime, compliance costs would increase to $6.5 billion for the same period. Consequently, the proposed PA mercury rule would increase the cost of operating coal-fired generation facilities in PA by $1.6 billion between 2009 and 2018, an additional annualized cost of approximately $160 million per year.

COMPARISON OF CUMULATIVE ANNUALIZED COMPLIANCE COSTS: 2009-2018 (in billion of 2006 $)

Rules	SO2	NOx	Hg	Total
CAIR/CAMR	3.35	0.83	0.76	4.94
CAIR/PA Rule	3.63	0.88	2.04	6.55
Differential Cost	0.28	0.05	1.28	1.61

[1] Annualized compliance costs included an annual capital charge for control technology, annual fixed and variable O&M costs for control technology, changes in annual fuel costs due to compliance and allowance costs.

Loss of $220 Million for Allowance Sales

Our analysis estimated SO2, NOx and mercury allowance sales for generators that had excess or banked allowances. These sales were netted out of the total annualized compliance costs for each emission under CAIR/CAMR. Allowance sales for all three emissions under CAIR/CAMR totaled $1.44 billion for the period 2009 through 2018. Of this total, mercury allowance sales by certain generators amounted to an estimated $220 million. However, this potential contribution to the capital investments and operating costs required to install and operate pollution controls would be foregone under the PA Rule, because the proposed rule does not allow for trading of mercury allowances.

Retirement of Smaller Units

Due to the PA Rule's limitation on trading, several older (>50 years old at the time of compliance) and high heat rate (>11,000 Btu/kWh) units would be forced to deploy mercury control technologies, which could render them uneconomic to operate. These mercury control costs would be in addition to compliance costs attributed to CAIR. There are 23 pulverized coal units representing 3,375 MW that could be classified as capacity "at risk" of retirement due to age and economics.

In addition, beginning in 2015, 16 fluidized bed waste coal units representing 2,422 MW would be unable to achieve their Phase II annual plant emission limitations, even with the deployment of an aggressive mercury control technology (FBCOHP). Therefore, the PA Rule could place 5,797 MW or 28 percent of the state's 2018 coal-fired capacity "at risk" of retirement.

Loss of PA Coal Markets

If the smaller and older pulverized coal units were retired, the Commonwealth could lose almost 85.1 million tons in coal production between 2010 and 2018. This translates to an average annual coal production loss of 9.4 million tons, equivalent to 14 percent of PA's 2004 coal production. Of particular note, we did not evaluate any switching to lower mercury coals, since those candidate units would have been at risk because of age and economics.

Implications for Electric Reliability

We did not evaluate the potential impact of the closure of older generating units on electric reliability within Pennsylvania or the PJM region, as this was beyond the scope of our study. However, given the magnitude of potential plant closures identified here, we believe that a separate evaluation of this issue is warranted.

EVALUATION OF THE COMPLIANCE IMPLICATIONS TO PENNSLYVANIA ELECTRIC GENRATORS OF MEETING GOVERNOR RENDELL'S PROPOSED MERCURY RULE

I. INTRODUCTION

On March 23, 2006, Governor Edward Rendell proposed a state specific mercury reduction plan (PA Rule) that would require coal-fired electric generating units (EGU) to reduce their mercury emissions significantly beyond the requirements of the U.S. Environmental Protection Agency's (EPA) Clean Air Mercury Rule (CAMR). Governor Rendell's plan would cut mercury emissions faster and more substantially than CAMR, targeting a 90 percent mercury reduction by 2015.

Briefly, the PA Rule requires EGUs to meet: (i) a percent reduction from input mercury in coal or an emission (output) standard or install a presumptive technology; **and**, (ii) an annual emission cap over two phases. The first phase (Phase I) begins in 2010 and extends through 2014, while the second phase (Phase II) goes from 2015 and beyond. The proposed rule prohibits the trading and banking of mercury allowances, but does allow electric generators to utilize facility averaging for compliance. As noted above, the proposed rule "presumes" that PC units with CS-ESP/FF, WFGD and SCR technology are already in compliance and would not be required to deploy additional mercury control technology to meet (i). However, a source must still meet the annual cap without the benefit of trading.

The purpose of this analysis is to evaluate the compliance costs to PA generators of meeting the reduction targets proposed in the PA Rule, and also to isolate the incremental compliance costs between CAMR and the PA Rule. To better understand mercury emissions attributed to PA generators, this analysis also included an evaluation the EPA's Clean Air Interstate Rule (CAIR) for PA generators. By modeling EPA's CAIR, one can better quantify and understand the level of co-benefits/mercury reductions that are attributed to CAIR compliance for PA generators. Therefore, this analysis included two modeling simulations: (i) PA generator compliance related to meeting CAIR/CAMR; and, (ii) PA generator compliance related to meeting CAIR/PA Rule. In addition, this analysis also discusses the major compliance implications for PA generators in achieving the targets and timetable of the PA Rule.

II. METHODOLOGY

This study employed the *Emission-Economic Modeling System (EEMS)*, a computer model designed to undertake emission and economic analyses of environmental polices and regulations. *EEMS* identifies a combination of control options (technology versus allowances) that approximates the least cost solution for a given utility system and regulatory (trading) regime. The order in which individual units are assumed to deploy their initial compliance option is determined by their dispatch order and removal costs ($/ton) with the cheapest units assumed to deploy control technology first. If it is a market-based trading regime, removal cost values are compared to allowance prices, to determine if technology is deployed or if allowances are purchased. However, under a command-and-control regulatory regime, *EEMS* systematically assigns control technology until the reduction target is achieved at the least possible cost.

CAIR SO2 and NOx & CAMR Mercury Allowance Allocations: The SO2, NOx and Mercury unit allowance allocations followed the model cap & trade rules outlined in both CAIR & CAMR. A brief discussion of these allocation procedures is as follows:

CAIR – SO2 Allocations

The CAIR unit SO2 allowances were determined by discounting 2010 Title IV allocations by 50% (dividing by 2) for years 2010 through 2014 and 65% (2.86) for the years 2015 and beyond.

CAIR – NOx Allocations

The allocation to units on-line before January 1, 2001 was based upon the average of the highest three years of heat input for the years 2000 – 2004. Fuel adjustment factors were applied (coal – 1.0, oil – 0.6, gas – 0.4) the average values. For those units that came on-line January 1, 2001 and thereafter, they received a unit allocation from a new source set-aside (NSSA) until they achieved a 5-year baseline. Whereas, an existing unit's baseline was determined by heat input, new unit baseline was determined by "modified output" format, which involved multiplying a unit's gross output by a stipulated heat rate (coal - 7,900 Btu/kWh and gas/oil – 6,675 Btu/kWh). Once a 5-year baseline was established, the average of the highest three years would be computed and added into the state's other existing units average heat input to compute an allocation proportion.

The NSSA for CAIR is 5% for the years 2009 – 2013 and 3% for 2014 and thereafter. The NSSA is allocated to units based upon the previous years NOx emissions and in most cases is pro-rated to units because the demand will exceed the availability of NSSA allowances.

CAMR – Mercury Allocations

The allocation to units on-line before January 1, 2001 was based upon the average of the highest three years of heat input for the years 2000 – 2004. Coal adjustment factors were applied (Bit. – 1.0, Sub – 1.25, Lignite – 3.0) to the annual heat input values. For those units that came on-line January 1, 2001 and thereafter, they received a unit allocation from a new source set-aside (NSSA) until they achieved a 5-year baseline. Whereas, an existing unit's baseline was determined by heat input, new unit baseline was determined by the same "modified output" format, which involved multiplying a unit's gross output by a stipulated heat rate (coal - 7,900 Btu/kWh). Once a 5-year baseline was established, the average of the highest three years would be computed and added into the state's other existing units average heat input to compute an allocation proportion.

The NSSA for CAMR is 5% for the years 2010 – 2014 and 3% for 2015 and thereafter. The NSSA is allocated to units based upon the previous years Hg emissions and in most cases is pro-rated to units because the demand will exceed the availability of NSSA allowances.

In terms of allowance trading under CAIR and CAMR, NOx allowances can be traded within 25-state NOx CAIR region and SO2 and Mercury allowances can be traded nationally, with no restrictions on banking

PA Annual Plant Mercury Emission Limits: As discussed earlier, the PA Rule calls for EGUs to meet either a percent reduction from coal input mercury levels or meeting an output emission standard, coupled with meeting an annual unit emission standard (cap) (see Section 123.207), over two phases. Since the proposed rule allows for facility-wide averaging, annual plant mercury emission limits (or non-tradable allowances) were computed for each facility, acted as the reduction target each plant would have to achieve to be in compliance with the PA Rule. The annual plant limits were determined in the following manner:

- Determine which of the two methods – Percent reduction from input fuel (input) or emission standard (output) is the most lenient for a plant and then set the plant limit to that level.

- Compare the value from bullet No. 1 to the annual limit and take the more stringent of these two. The computed annual limit was based upon allocation procedures outlined in Section 123.207 of the proposed rule. This selection process insures that PA Rule annual mercury emission limits are below the CAMR state budget.

An affected unit for the both CAIR, CAMR and the PA Rule followed the definitions outlined in all three rules, which are fossil (coal for CAMR/PA Rule) generating units greater than 25 MW and sells one-third of its power to the grid.

Generation, Fuel and Allowance Prices: 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) and Mid-Atlantic Area Council (MAAC). The basis of this forecast was the projected regional electric demand by fuel type from the Energy Information Administration's (EIA) *Annual Energy Outlook 2006 (AEO2006)* taking into account the implementation of CAIR and CAMR. In addition, future regional coal and gas prices were also based upon EIA's *AEO2006* taking into account the implementation of CAIR and CAMR.

The table below illustrates the projected CAIR (SO2, NOx) and CAMR (mercury) allowance prices in 2006 dollars for selected years. This allowance price forecast was derived from CRA International's *North American Electricity and Environment Model (NEEM)* based upon our control assumptions. The SCR basis for NOx allowance prices was \$200/kW and the FGD basis for SO2 allowance prices was \$300/kW. The basis for the mercury allowance prices was \$120/kW for a COHPAC and \$35/kW for ACI and halogenated ACI, which includes upgrades to the ESP with SCA of 250 or less.

TABLE 1
CAIR AND CAMR ALLOWANCE PRICES
(2006 $)

	SO2($/ton)	NOx($/ton)	Hg($/lb)
2009	0	1,833	0
2010	745	2,069	39,311
2013	913	1,791	40,959
2015	1,046	2,050	46,892
2018	1,282	2,512	57,447

Note: 1. The CAIR SO2 allowance prices reflect the discounting of Title IV allowances by 50% (2.0) from 2010 – 2014 and 65% (2.86) for 2015 and beyond.

Compliance and Control Technology Choices: Those control options that were evaluated in this analysis to meet both CAIR/CAMR and the CAIR/PA Rule, which are discussed in detail in Appendix A for SO2 and NOx control technologies and Appendix B for mercury control technologies of this report, are as follows:

SO2 Controls
- Wet FGD (WFGD)
- Dry FGD (DFGD)
- Fuel Switching (FS)[2]

NOx Controls
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- SIP Call SCR operating an additional 7 months – (7SCR)

Mercury Controls
- Activated Carbon Injection (ACI)
- Halogenated Activated Carbon Injection (HACI)
- COHPAC (COHP)
- Halogenated COHPAC (HCOHP)
- Fabric Filter (FF)
- FBC – COHPAC (FBCOHP)

Appendix B presents an array of mercury control technologies based upon unit specific characteristics. It should be noted the mercury control efficiencies, presented in the appendix, are applied to the input mercury in coal

An extremely important technology deployment rule is that units older than 50 years at the time a compliance decision is required *do not* receive any control technology under CAIR/CAMR. However, under the CAIR/PA Rule simulation this ruled was relaxed, because of

[2] Fuel Switching takes into account switching from high sulfur to low sulfur coal, as well as switching from a low or compliance coal to a high sulfur when installing a FGD system.

the stringency of the PA Rule, and units older than 50 years at the time a technology decision was required *would be eligible* for mercury control technologies.

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. For CAIR and CAMR compliance, the methodology is to select technology for an EGU if the removal costs are below the allowance price and if the technology represents the minimum removal cost for that unit including any banked allowances for more robust technologies (e.g. SCR vs SNCR). For the PA Hg rule, all feasible combinations of technology assignments at a facility were compared to find the lowest cost option that removed sufficient mercury. Additionally, certain restrictions were applied including using only one type of carbon sorbent at a facility (e.g. HACI and HCOHP is acceptable but HACI and COHP is not).

Capital and operating costs were developed based upon industry experience in retrofitting recent SO2, NOx and mercury control technologies. It should be noted, that the above mentioned control assumptions represent realistic assumptions, in terms of applicability and performance. Further details of these control assumptions and costs are described in Appendix A.

III. COMPARISON OF THE COMPLIANCE EFFECTS OF MEETING CAIR/CAMR AND CAIR/PA RULE

To meet the targets and timetables of CAIR/CAMR, PA generators would have to invest $1.62 billion in SO2, NOx and mercury control technologies, as illustrated in Table 2. However, under a CAIR/PA Rule regulatory regime, capital investment in control technologies is expected to reach almost $3.29 billion, of which $1.74 billion or 53 percent of this investment would be attributed to mercury control technologies. Under a CAIR/PA Rule regulatory regime, PA generators would have to invest an additional $1.67 billion in control technology, which is double the investment they would have to make under CAIR/CAMR.

TABLE 2
CAPITAL INVESTMENT OF SO2, NOx AND MERCURY CONTROL TECHNOLOGIES: 2009 – 2018
(in billions of 2006 $)

Rules	SO2	NOx	Hg	Total
CAIR/CAMR	1.05	0.33	0.24	1.62
CAIR/PA Rule	1.22	0.33	1.74	3.29
Differential Cost	0.17	0	1.50	1.67

The cumulative annualized compliance costs for PA generators between 2009 and 2018 under CAIR/CAMR are projected to be $4.94 billion, as shown in Table 3.[3]. However, under a CAIR/PA Rule regulatory regime, compliance costs are projected to be $6.55 billion for the same 2009 to 2018 time period. Consequently, the proposed PA rule would increase the cost of operating coal-fired generation facilities in PA by $1.61 billion between 2009 and 2018. These incremental costs are not only attributed to complying with the proposed mercury rule, but this rule would also induce additional costs to meet CAIR for PA generators.

TABLE 3
COMPARISON OF CUMULATIVE ANNUALIZED COMPLIANCE COSTS: 2009-2018 (in billion of 2006 $)

Rules	SO2	NOx	Hg	Total
CAIR/CAMR	3.35	0.83	0.76	4.94
CAIR/PA Rule	3.63	0.88	2.04	6.55
Differential Cost	0.28	0.05	1.28	1.61

This analysis included allowance sales for those generators that had excess or banked allowances. These sales were netted out of the total annualized compliance costs for each gas under CAIR/CAMR. Allowance sales for PA generators under CAIR/ CAMR totaled $1.44 billion for the years between 2009 and 2018. Of particular note are the potential allowance sales under the CAMR between 2010 and 2018. PA electric generators (Allegheny, Edison Mission, First Energy & PP&L) would have an accumulated value of $220 million in mercury allowances under CAMR during the 2010 – 2018 time period. However, this potential asset would be

[3] Annualized compliance costs included an annual capital charge for control technology, annual fixed and variable O&M costs for control technology, changes in annual fuel costs due to compliance and allowance costs.

foregone under the PA Rule, because the proposed rule does not allow for banking and trading of mercury allowances.

CAIR SO2 Compliance

To comply with a CAIR/CAMR regulatory regime, PA generators will have to install six additional FGD systems on their units beginning in 2010 to meet CAIR. These six FGD systems are in addition to the five CAIR FGDs that have been already announced and are currently under development. Therefore, by 2018, PA generators will have 16,411 MW of FGD systems operating on their units, which would represent 78.3 percent of their coal-fired capacity (20,961 MW).

Of particular note is the type of FGD system that is being predicted. The modeling estimates the retrofitting a DFGD system burning a Northern Appalachia Medium Sulfur (NAMS) coal would be a more cost-effective option than switching to a Northern Appalachia High Sulfur (NAHS) coal and deploying a WFGD system. These DFGD systems have removal costs that range between $415 to $620/ton. Consequently, the removal cost differential between the wet and dry system averages about $97/ton in favor of the DFGD. This $97/ton savings is attributed to the high capital cost of WFGD coupled with the high variable O&M cost for high sulfur coals; thereby, negating the fuel savings in switching to a higher sulfur coal. While the higher sulfur coal can be used with the wet scrubber, thereby saving on the cost of coal, that higher inlet SO2 results in a higher input and final emission rate than the DFGD. Both systems remove the same percentage of SO2 and the coal savings is not enough to offset the greater *net removal* of the dry system when calculating the dollar per ton removal costs.

The primary factor affecting the increase in CAIR SO2 compliance cost under the CAIR/PA Rule regime is the deployment of a WFGD on Keystone 1 & 2, instead of the modeled DFGD under the CAIR/CAMR simulation. The driving factor for switching FGD types from dry to wet is to allow Keystone 1 & 2 to achieve reduction limits outlined in the PA Rule. The remaining four modeled CAIR DFGD systems are still deployed.

CAIR NOx Compliance

Under the CAIR/CAMR regulatory regime, the modeling projected three additional SCRs would have to be installed on PA generating units to meet CAIR. Of these three SCRs, two would have to be installed by 2010 and the third SCR by 2016. The removal costs for these new SCRs range between $1,750 to almost $2,200/ton. In addition, eight existing SIP Call SCRs would be operated year round. These SCRs provide inexpensive NOx reductions by operating an additional 7 months (7SCR), with the incremental removal cost ranging between $211 to $305/ton. We also project 5 additional SNCR systems would have to be installed by PA generators. These SNCR systems would have removal costs between $1,000 to $1,800/ton and achieve NOx removal efficiencies of between 25 to 40 percent, depending on unit size.[4]

[4] When deciding between SCR and SNCR for units in which both technologies viable and under the year's allowance price, the additional removal with SCR was considered by multiplying the extra removal by that year's allowance price. This allows for the modeling of the actual least-cost option for the unit.

Therefore, to comply with CAIR NOx provisions, PA generators will primarily rely on a combination of extending the operation of existing SIP Call SCR equipment year-round, the installation of both SCR & SNCR technology, and NOx allowance purchases. However, by 2018, PA generators will have deployed and be operating year-round, 10,431 MW of SCR capacity which would represent 50 percent of state's total coal-fired capacity.

The primary factor impacting the increase in CAIR NOx compliance costs under the CAIR/PA Rule regime is a result of moving up a projected SCR on Conemaugh 2 from 2016 to 2015, in order to achieve the maximum level of co-benefit control.

CAMR and PA Rule Compliance

The modeling indicated a relatively small number of retrofit carbon systems were assigned to PA under CAMR. There are four primary reasons why fewer systems are seen in the CAMR compliance than in previous Hg analyses which included Pennsylvania.

- A general increase in the cost of retrofitting COHPAC systems is seen here based on recent engineering studies in the Midwest
- The assumption that activated or halogenated carbon injection systems require an ESP SCA of least 250, adding $25-$35/kw in capital costs to these processes for many units in PA.
- The CAMR national trading regime allows PA operators to buy allowances at a lower price than many technologies would cost them.
- Higher co-benefits are seen with Dry FGD systems that are retrofit to units with an existing ESPC.

More specifically, by 2018, 2,181 MW of PA's coal-fired capacity would have installed mercury control technologies at a removal cost of not exceeding $47,530 per pound on units not exceeding 50 years old at the time of compliance. Many of eligible coal units have minimal removal costs ranging from $48,000 to $299,000 per pound; consequently, CAMR allows PA electric generators the flexibility to make the most rationale, cost-effective and least costly compliance decisions with regard to mercury compliance.

Under the PA Rule, PA generators would have to expend almost $2.04 billion between 2010 and 2018 to meet and maintain the reduction requirements spelled out in the rule. These compliance costs are $1.28 billion above the compliance costs estimated for CAMR compliance ($760 million) for PA generators over the same period. The rule's cumulative costs between 2010 and 2018 would require PA generators to spend an additional $161 million per year to operate their PA coal-fired generating units. The PA Rules forces PA generators to install technology on 13,494 MW of their coal-fired capacity, which represents 64 percent of state's total coal-fired capacity. Due to the rule's prohibition to mercury allowance trading, PA generators are forced to install not only technology on older/uneconomical units, but to install the more expensive filter technology (COHP, HCOHP, FF and FBCOHP) to control mercury. Specifically, almost 71 percent of the projected mercury control technology will be filter technology; thereby, it will not be unusual to see removal costs in excess of $75,000 per pound.

Of particular note, the 10 units representing 5 coal plants, in which the State assumes, would be "presumed compliant" under Section 123.206; none of these 5 coal plants would be under their plant emission limit for the entire 2010 and 2018 time period.[5] Therefore, many of these units would have to install some type of mercury control technology, primarily in the second phase (2015) of the PA Rule, in order for that facility to achieve the rule's plant emission limitation. For example, PA electric generators would have to invest $445.7 million in mercury control equipment for these 5 coal plants to meet the plant level emission limitation of cap.

Comparative Emission and Economic Implications between CAMR and the PA Rule

The previous sections focused upon compliance cost differences between CAIR/CAMR and CAIR/PA Rule. The focus of this section is to isolate the emission and economic effects between CAMR and the PA Rule. As shown in Table 4, PA generators will reduce their mercury emissions between 2010 and 2015 by 6,000 pounds due to compliance with CAIR. This reduction increases to 6,400 pounds after 2015. These reductions represent more than a 50 percent reduction from Pre-CAIR emission levels. In meeting CAMR, PA generators would reduce their emissions, on average, an additional 16 percent, under this cost-effective regulatory regime. Therefore, for compliance with CAIR/CAMR, PA generators will have reduced their Pre-CAIR & Pre-CAMR mercury emissions by 60 percent between 2010 and 2018.

Although the CAMR budgets and PA emission limitations are very similar, the two primary factors that significantly impact compliance between CAMR and the PA Rule are:

- Phase II of the PA Rule begins in 2015, instead of 2018 for CAMR;
- PA Rule only allows for facility-wide averaging, with no banking of allowances compared to interstate trading and banking of allowances under CAMR.

The PA Rule, through its more command-and-control regulatory regime, will reduce mercury emissions in the state; however, it will come at a greater cost to in-state generators than to those of other states in the region who will be using a less restrictive trading regime. As shown in Table 4, the annualized compliance costs for the PA Rule are almost double of CAMR between 2010 and 2017; with the incremental cost ($pound) of moving from CAMR to the PA Rule is more than one and half times greater than costs of CAMR. The marginal cost of control for the PA Rule will almost reach $358,000 per pound between 2010 and 2017, which indicates that technologies are deployed on smaller and less-efficient coal units. In 2018 when the CAMR state budget closely approximates the PA Rule emission limitation, the annualized compliance costs begin to narrow, but the average control cost ($/pound) still remains significantly higher under the PA Rule, with the marginal cost of control under the PA rule reaching almost $458,000 per pound.

[5] The 10 units are Bruce Mansfield 3, Conemaugh 1 & 2, Montour 1 & 2, Homer City 1 – 3 and Keystone 1 & 2.

TABLE 4
COMPARATIVE EMISSION AND ECONOMIC EFFECTS OF CAMR & PA RULE
(emissions in pounds and 2006 millions of dollars)

Category	2009	2010	2013	2015	2018
PA Pre-CAIR	0	11,664	11,691	11,758	11,841
PA After CAIR	0	5,675	5,692	5,747	5,424
CAMR Emissions	0	4,755	4,687	4,688	4,644
CAMR Budget	0	3,560	3,560	3,560	1,404
CAMR Compliance Costs	0	105.5	104.4	116.3	215.5
CAMR $/lb		35,861	36,826	40,638	55,249
PA Rule Emissions	0	2,140	2,146	1,664	1,779
PA Rule Hg Limits	0	3,359	3,371	1,399	1,400
PA Supplement Pool	0	1,219	1,226	-265	-379
PA Rule Compliance Costs	0	201.0	201.1	259.6	259.4
PA Rule Incremental Cost beyond CAMR $/lb	0	66,931	67,565	75,356	77,938

Note: 1. PA Pre-CAIR Hg emissions does include the FGDs planned for Montour, Brunner Island and Homer City 1&2, as well as the six modeled FGD systems and two modeled SCR systems.
2. CAMR compliance costs include annualized technology costs and allowance purchases minus allowance sales.

As shown in the table above, the PA Emission Limit Supplement Pool would be positive during the rule's first phase (2010 – 2014); thereby, allowing those units that can not achieve their plant-wide limitations to petition the state for additional non-tradable mercury allowances. However, beginning in Phase II (2015 and beyond) the Emission Limit Supplement Pool would be negative or inadequate to meet the emission demand for those units over their emission limitations. The primary factor contributing to this negative supply is that PA generators are unable to reduce their mercury emissions to a level below 1,400 pounds based upon current technology. Consequently, this would make several PA generators non-compliant with the PA rule's annual emission limitations, as well as in violation of the CAMR State Budget beginning in 2018.

Potential Capacity at Risk under the PA Rule

Due to the PA Rule's limitation on trading, several older (age >50 years old at the time of compliance) and high heat rate (>11,000 Btu/Kwh) units would be forced to deploy mercury control technologies, which could render them uneconomical. These mercury control costs would be in addition to compliance costs attributed to CAIR. There are 23 units representing 3,375 MW that could be classified as capacity "at risk" of retirement due to age and economics. In addition, beginning in 2015, 16 FBC units representing 2,422 MW would be unable to achieve their Phase II annual plant emission limitations, even with the deployment of an aggressive mercury control technology (FBCOHP). Therefore, the PA Rule could place 5,797 MW or 28 percent of the state's 2018 coal-fired capacity "at risk" of retirement.

If this coal capacity is retired, the state could lose almost 85.1 million tons in coal production between 2010 and 2018, which translates into an average annual coal production loss of 9.4 million tons, equivalent to 14 percent of PA's 2004 coal production. Of particular note, we did not evaluate any switching to lower mercury coals, since those candidate units would have been at risk because of age/economics.

Implications for Electric Reliability

We did not evaluate the potential impact of the closure of older generating units on electric reliability within Pennsylvania or the PJM region, as this was beyond the scope of our study. However, given the magnitude of potential plant closures identified here, we believe that a separate evaluation of this issue is warranted.

IV. CONCLUSIONS

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

- PA electric generators would reduce their mercury emissions by 60 percent due to CAIR/CAMR compliance;
- The PA rule would force PA generators to invest an additional $1.67 billion into their coal-fired generating units to control mercury, which is double the capital investment required by CAIR/CAMR;
- The PA rule would increase the cost of operating the state's coal-fired facilities by $161 million per year;
- The inflexibility of the PA Rule requires the deployment of more expensive filter technology to control mercury on older/uneconomical units;
- Total state mercury emissions *will not be under* the rule's Phase II state emission limitation beginning in 2015;
- Under the PA rule, the state *will be over* (in violation) their CAMR State Budget beginning in 2018;

- The PA rule could put 28 percent of the state's coal-fired capacity "at-risk" of retirement; and,
- Compliance with the PA Rule could displace almost 85.1 million tons of PA coal between 2010 and 2018.

APPENDIX A

SUMMARY OF ASSUMPTIONS DEFINING THE FEASIBILITY AND COST OF SO2, NOx, AND PARTICULATE MATTER OR CAIR-MANDATED COMPLIANCE

INTRODUCTION

Appendix A to this report presents additional detail regarding the assumptions defining the feasibility and cost of control technology for SO2, NOx, and particulate matter Appendix A serves as the basis of descriptive material that was presented in the final report. Appendix B addresses the same information for mercury control technology.

This work consisted of simulating industry decision-making in defining the least cost compliance plan. For a state-specific analysis in which approximately 100 individual units will be evaluated, a limited number of technical options were considered, to restrict the nature of the problem. These options represent in the broader selection of alternative equipment and processes.

Specifically, it is well known that many choices exist from which to select flue gas desulphurization 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, the two key flue gas desulfurization options – wet conventional limestone-based and lime-base dry FGD – were evaluated. This assumption should not be interpreted to suggest that only these technologies are viable for power producers within the Il and PA; in fact a broad range of equipment should be considered. However, these options represent most of the near-term practical choices, and any other options will likely exhibit similar incurred levelized cost, considering both capital and operating requirements.

Similarly, with respect to NOx, two control options are considered – selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). The use of SNCR was included to provide an option to capital-intensive, high NOx removal SCR. In reality, there are a number of technologies relatively low in capital cost, which exhibit the low-moderate NOx removal typical of SNCR. These include both natural gas reburning and coal reburning, as well as several variants of these processes (e.g. NOxStar). In the context of the present analysis, SNCR is considered a surrogate for lower cost alternatives to SCR – thus SNCR is considered representative of such 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.

Although Hg control assumptions are addressed in Appendix B, the cost of particulate matter control equipment or upgrades that may be required for Hg processes is addressed in this section. Two particulate matter control options are considered – one an upgrade of the existing ESP, and the second a stand-alone fabric filter. For an existing ESP, it is assumed a minimum SCA of 250 ft^2/kacf is required to sustain activated carbon injection without operating problems, thus one additional collecting field is added for small units to meet this criteria. Also, a fabric filter can be retrofit following an ESP - the concept referred to by EPRI as COHPAC. Finally, a fabric filter can be installed in place of an ESP.

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, NOx and mercury.

DATA SOURCES

The source of cost information depends on the control technology. The cost analysis includes capital, fixed operating and maintenance (O&M), and variable O&M costs for various control technologies.

For FGD, a mix of both (a) actual costs incurred and reported for completed projects, and (b) detailed estimates by major architectural/engineering (A/E) firms have been used. For SCR, the cost basis is actual costs incurred for completed projects, based on a survey of costs reported in 2004. The results of this survey were corroborated in a more recent survey, and thus are considered valid.

For activated carbon injection (ACI), a mix of both cost estimates (a) reported in the literature for generic application, and (b) developed by A/E firms for a specific unit or units was employed.

The cost evaluation employs those values determined for individual units, adjusted as necessary into a 2006 dollar basis. Units for which specific cost estimates have not been developed are costs from a generic relationship of capital versus generating capacity, based on cost data submitted by participating Owners. Cost data from other sources is used, but only when credible and referenced.

SCOPE OF ANALYSIS

The scope of the cost estimates include (a) process equipment, (b) installation and construction, (c) allowance for funds used during construction, (d) engineering charges, (e) owners costs and incurred charges, and (f) 10-15% project contingency. Some cost estimates also include a nominal charge for the engineering/procure/construct (EPC) contractor. This fee, usually 8%, is incurred by the EPC contractor to provide turnkey final design, installation, and startup. It is reported that Owners electing to not utilize an EPC approach and instead employ an A/E firm to supervise procurement will avoid the EPC fee but incur A/E fees approximately the same. Given the range of engineering charges used – 10 to 15% - the EPC fee although not small will not affect the outcome.

COST BASIS

The costs reported are expressed in 1Q2006 dollar basis. Operating costs are also reported on this basis and not levelized over the projected 20 or 30 year period to account for escalation, and other factors.

FLUE GAS DESULFURIZATION

Both conventional wet limestone and dry lime-based FGD are considered in this analysis.

Wet FGD

The reference wet, limestone-based FGD process is based on the conceptual design as described by an analysis conducted for the National Lime Association by Sargent & Lundy Engineers (Sargent & Lundy, 2003). Wet FGD technology will be assigned to units according to unit size, number of units at a station, and coal type. Stations with multiple, smaller units will utilize one absorber vessel for several units. The following rules will be applied:

- Units of 100 MW capacity or less will not receive any FGD
- Units from 100-300 MW will consolidate flue gas flow into one absorber; however, the common absorber should not exceed a flue gas treatment capacity greater than 500 MW.

The SO_2 removal efficiency was assumed to depend on the coal sulfur content. Table A-1 presents the SO2 removal capability assumed for both PRB and a medium-high sulfur coal. The lower SO2 limit for PRB is consistent with basic FGD design, and as well as experience with at least one FGD-equipped unit firing predominantly PRB (ref). Table A-1 also reports the energy penalty due to wet FGD, in terms of (a) auxiliary power consumption, and the power generated that cannot be sold into the market, and (b) the maximum capacity penalty, or the fraction of maximum generating capacity lost.

The main source of cost information for conventional limestone-based FGD is an analysis prepared for a number of utilities in Illinois and Pennsylvania, as well as reported, incurred costs. The capital cost estimates are shown in Figure A-1.

Regarding operating costs, Fixed O&M are presented in Figure A-2, and are based on detailed engineering analysis of various units. Variable O&M costs were selected from Table A-1, also based on engineering study. Both the fixed and variable O&M costs are similar to those developed from CUECost, which summarizes variable O&M for the three categories of coal.

Table A-1 - Wet FGD Design and Operating Variables

Coal Type	SO2 Removal: Baseline Design	Capacity Penalty (% of capacity)[6]	Energy Penalty (% of capacity)
PRB	93	2.0	1.5
Medium Sulfur	98	2.0	1.5
High Sulfur	98	2.0	1.5

[6] Derived from Sargent & Lundy, 2003

Figure A-1 – Conventional Wet FGD Capital Cost Estimates

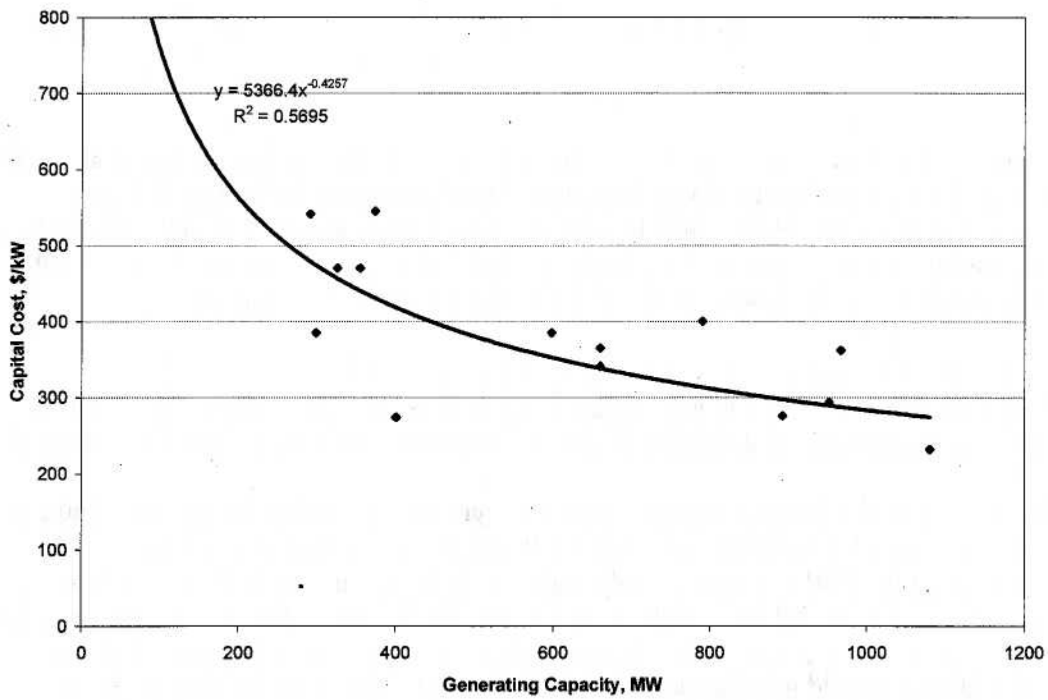
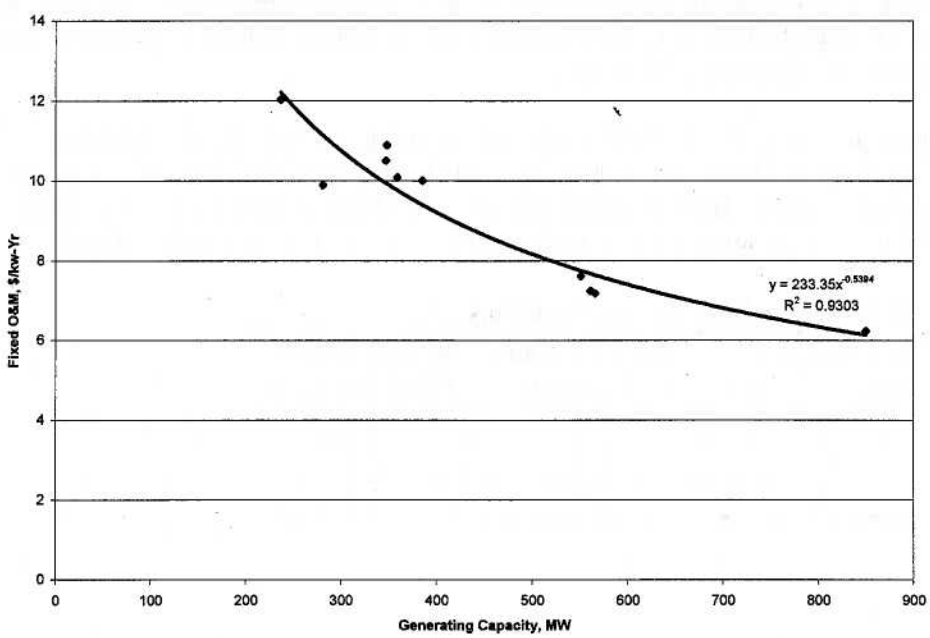


Figure A-2 – Fixed O&M Costs: Conventional Wet and Dry FGD



The variable O&M is summarized as follows:

Table A-2. Summary of Conventional Wet FGD Variable Operating Costs

Coal Sulfur Designation	SO2, lbs/MBtu	Cost Basis (mills/kWh)
High Sulfur	5.5. lbs/MBtu	3.2
Medium/High	4.5-5.5 lbs/MBtu	2.7
Medium	2.25-<4.5	2.2
Low	<2.25	1.5

Existing Wet FGD Upgrades

For existing FGD processes in operation by in-state power producers, the prospect of upgrading existing equipment to improve performance has been addressed 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. For the purpose of this study, it was assumed that existing FGD upgrade is feasible, but it is important to recognize this is an assumption and not the result of a unit-specific analysis.

Table A-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, improved reagent preparation, 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, improved quality of reagent, the use of a buffering additive, and higher auxiliary power to improve mass transfer.

Table A- 3 - FGD Upgrade Assumptions

SO2 Removal Increment	**70->93**	**80→93**
Capital ($/kW)	35	25
Operating cost (mills/kwh)	0.35	0.25

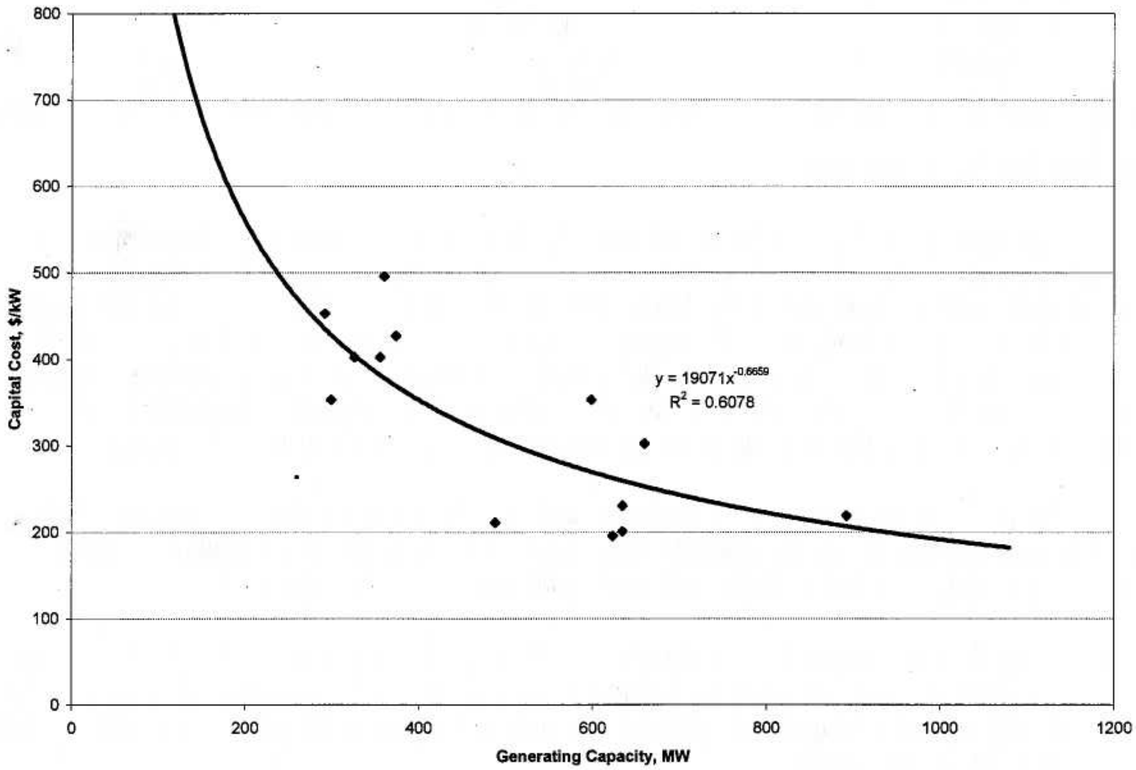
The analysis conducted for in-state power producers used this information to evaluate the feasibility of upgrading existing FGD to derive additional SO2 reductions.

Dry FGD

The reference dry, lime-based FGD is based on the conceptual design as described by an analysis conducted for the National Lime Association by Sargent & Lundy Engineers (2002).

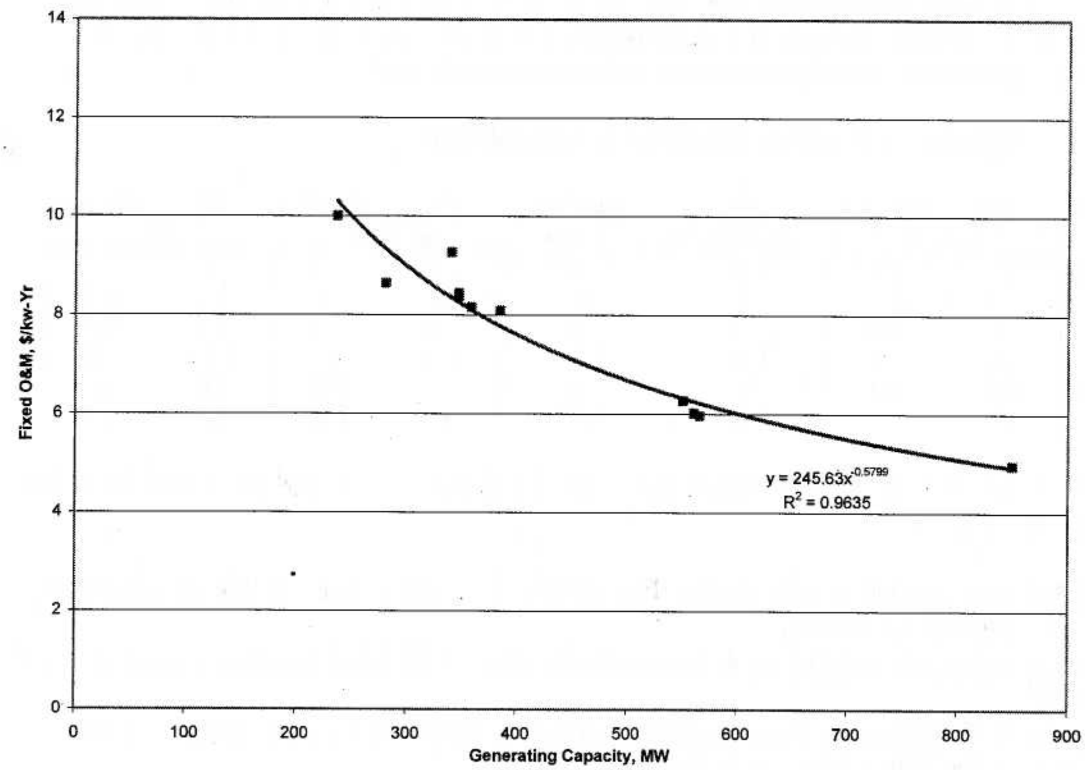
Capital costs for dry FGD equipment including a fabric filter for particulate matter removal were presented in Figure A-3. Notably, in all cases dry FGD with a fabric filter requires less capital cost than wet FGD.

Figure A-3. Dry FGD Capital Cost



Fixed O&M costs depicted in Figure A-4 are also notably less than for wet FGD, mostly due to lower manpower requirement for less complex equipment.

Figure A-4. Dry FGD Fixed Operating Costs



Variable operating costs for dry FGD processes have been projected for PRB coal – the prime fuel to which dry FGD equipment is considered . Variable operating costs are anticipated to be approximately 1.05 mills/kWh. This cost includes reagent, auxiliary power cost for FGD equipment, for the fabric filter module both replacement filter media and auxiliary power.

NITROGEN OXIDES

Several NOx control options 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 two options should not be interpreted as an endorsement of these technologies 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. In addition, combustion controls should be upgraded prior to deploying post-combustion controls, to maximize NOx removed and minimize cost.

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 A-5 describes the performance and cost of both low NOx burners (LNB) and over-fire air (OFA). For each unit, the reported 2004 NOx emissions were compared to the NOx rates in Table A-5, 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 A-5 - 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 A-5 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 5

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 A-6 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 A-6, 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.

Table A-6. 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

SCR

SCR capital and operating cost are presented in Tables A-7 and Figure A-5. Table A-6 presents fixed and variable operating cost, as a function of boiler type, and initial NOx rate. Figure A-5 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 A-5 was derived based on a survey of actual SCR costs incurred by domestic U.S. power producers (Cichanowicz, 2004). As Figure A-5 represents actually incurred costs, and has been corroborated by a second, more recent survey (Marano, 2006), these values are used in the economic evaluation of SCR on units for which a site-specific estimate does not exists.

Table A-7 presents SCR operating and maintenance costs as a function of boiler inlet NOx rate, showing both variable and fixed O&M.

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 (a) 0.045 lbs/MBtu for PRB, (b) 0.05 lbs/MBtu for subbituminous coal with < 1.2% sulfur, (c) 0.06 lbs/MBtu for bituminous coal with sulfur content between 1.2 and 2.5%, and (d) 0.07 lbs/MBtu for bituminous coal with sulfur content > 2.5%. 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 A-5. SCR Capital Cost

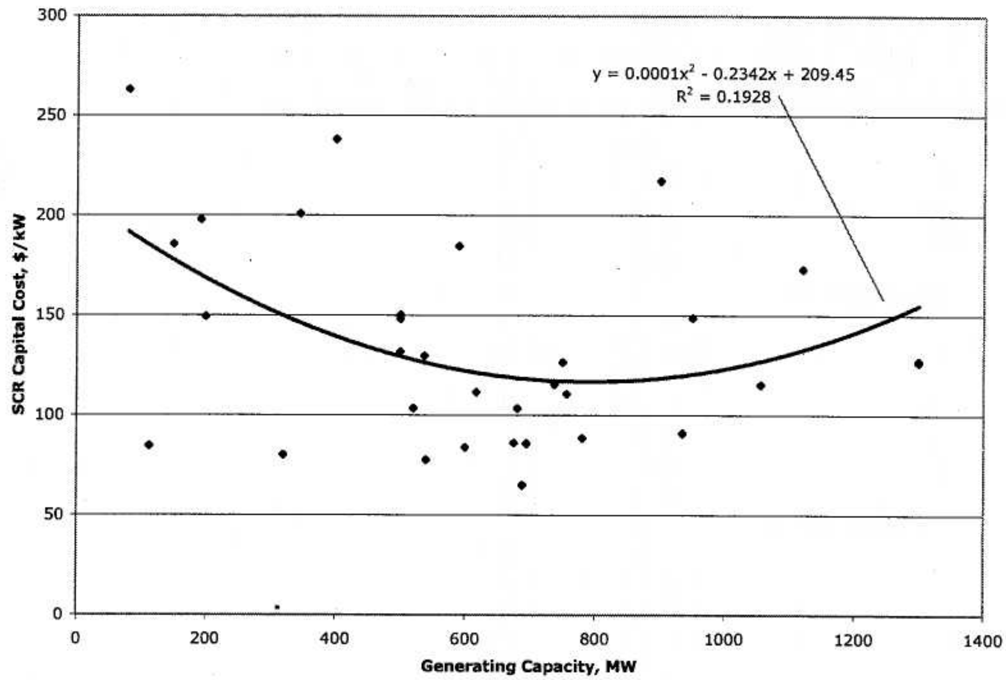


Table A-7. SCR Fixed, Variable Operating Costs

Capacity (MW)	Burner Firing Type t-tangential; f- front-fired; o - opposed fired	Initial Boiler NOx (lbs/MBtu)	SCR O&M ($/MWh)	SCR Fixed O&M (% of Capital /yr)
>500	t-f-o	0.20-0.30	0.52	0.75
	t-f-o	0.31-0.40	0.62	
	t-f-o	0.40-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.97	
	"	>0.65	1.02	
	cyclone/wet-bottom	<0.86	1.15	
	"	>0.86	1.2	
400-500	t-f-o	0.20-0.30	0.52	0.75
	t-f-o	0.31-0.40	0.62	
	t-f-o	0.40-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.97	
	"	>0.65	1.02	
	cyclone/wet-bottom	<0.86	1.15	
		>0.86	1.2	
300-400	t-f-o	0.20-0.30	0.52	0.75
	t-f-o	0.31-0.40	0.62	
	t-f-o	0.40-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.97	
	"	>0.65	1.02	
	cyclone/wet-bottom	<0.86	1.15	
	"	>0.86	1.2	
200-300	t-f-o	0.30-0.40	0.62	0.75
	t-f-o	0.41-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.62	
	"	>0.65	0.75	
	cyclone/wet-bottom	<0.86	1.15	
	"	>0.86	1.2	
126-200	t-f-o	<0.40	0.62	0.65
	t-f-o	0.40-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.62	
	"	$\boxed{>0.65}$	0.75	
	cyclone/wet-bottom	<0.86	1.15	
	"	>0.86	1.2	
75-125	t-f-o	<0.40	0.7	0.5
	t-f-o	0.40-0.50	0.8	
100	t-f-o	>0.50	0.9	
	cell	all	1.2	
	cyclone/wet-bottom	all	1.2	

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 and Central Appalachia. 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:

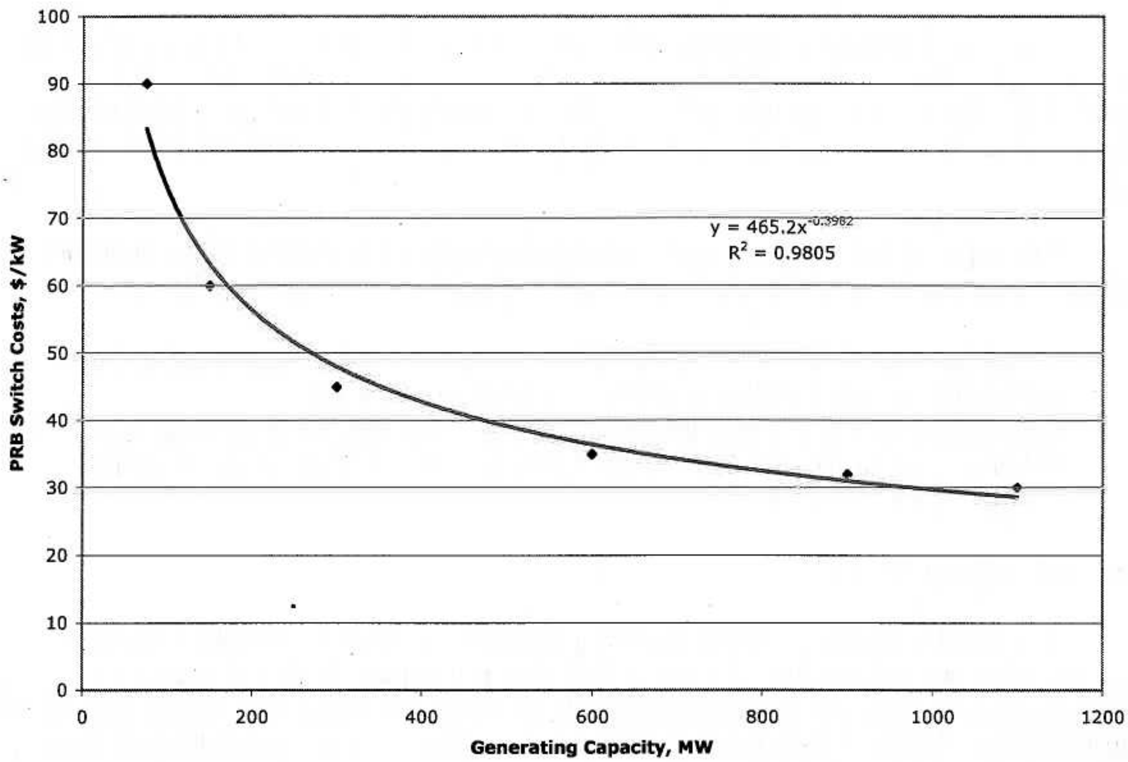
- Switching from a higher sulfur bituminous coal to a low sulfur bituminous (Central Appalachia) or sub-bituminous (PRB) coal, to avoid FGD, and
- Determining the optimal combination of FGD and coal type, by considering both FGD O&M cost for each of sub-bituminous (PRB), and low, medium or higher sulfur 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 or a low sulfur Central Appalachia coal from either medium or high sulfur coal usually requires capital investment to maintain thermal performance and minimize capacity de-rate. .

Of the coal switch options considered in this study, only switches to PRB/Central Appalachia coals required capital investment. Figure A-6 presents the relationship between capital cost to accommodate PRB/Central Appalachia coal and generating capacity, as determined from the survey of operators.

Figure A-6. Switching to PRB Coal vs Unit Capacity



PARTICULATE MATTER CONTROLS

Control technology equipment for particulate matter, although not directly driven by compliance issues for CAIR, is relevant in the context of Hg control. Appendix B is dedicated to defining the candidate Hg control processes, and assumptions defining the degree of Hg control. However, assumptions defining the capital and operating cost of equipment that may be necessary for retrofit to support Hg controls are discussed in this section.

Figure A-9 presents the capital cost of a fabric filter for particulate matter control as a function of generating capacity. These data describe the installed cost for units including additional ductwork, flue gas fans, and other ancillary operating equipment. These capital cost estimates, derived from units both designed as stand-alone particulate matter collectors and as second particulate collectors for dry FGD, reflect a range of air/cloth ratio of between 4/1 and 6/1. Figure A-10 presents the fixed O&M costs for the fabric filter particulate matter collectors as a function of generating capacity.

Figure A-9. Fabric Filter Capital Cost As a Function of Generating Capacity

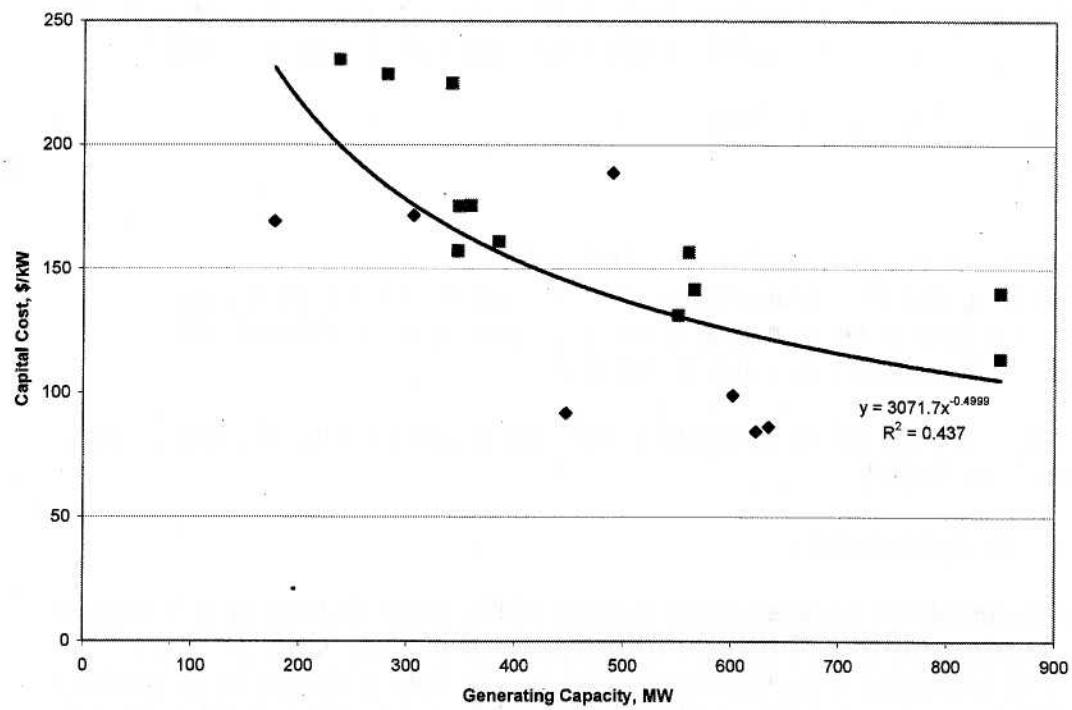
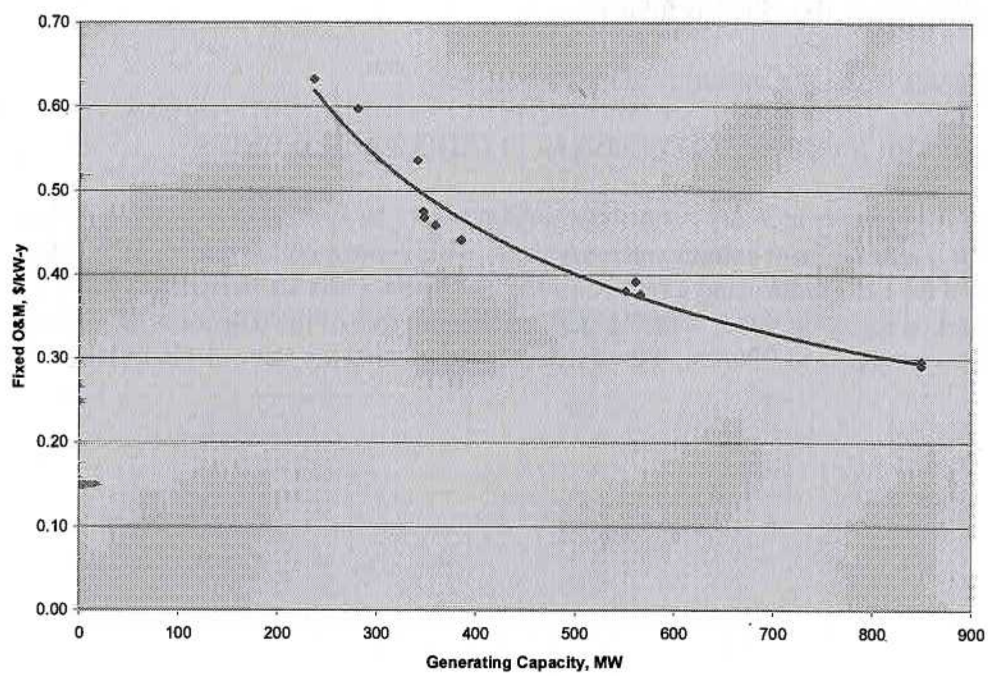


Figure A-10. Fixed Operating & Maintenance Costs for Fabric Filter Particulate Collectors



Variable operating costs for the fabric filter for PM control alone is presumed to solely consist of auxiliary power consumption, due to an assumed 6 in w.g. $H2O$ pressure drop. The auxiliary power required by the fan will be calculated using the following relationship:

Power = 0.000181 * Q * deltaP * Time

Where:

- Power is the required power consumption, in kWh/y
- Q is the system flowrate processed, in terms of actual cubic feet per minute,
- deltaP is the pressure drop incurred across the filter, in terms of inches H2O
- Time is the operating time in hours per year

The resulting power tem will be multiplied by the assumed cost for value of auxiliary power, presumed to be $30/MWh.

Electrostatic Precipitator (ESP)

Units considering activated carbon injection will be assumed to require an increase in specific collecting area, SCA, if the value reported is less than 250 ft2/kacf. The cost for the increase in SCA beyond 250 SCA will be assumed to be $35/kW, as defined by the analysis of Boward (1997), escalated to a 2006 dollar basis and including adjustments as defined by utility-specific studies for these modifications. The capital cost of $35/kW, as determined for a 250 MW unit, will be generalized to other generating capacities by a power-law relationship, using a 0.35-power scaling factor, described as follows;

ESP Upgrade Cost (@ Capacity) = $35 *(250/\text{Capacity})^{-0.35}$

ACI/FABRIC FILTER (COHPAC/TOXECON) for FLUIDIZIED BED UNITS

This is an aggressive mercury control option that would be applied to any fluidized bed combustion (FBC) units to meet extreme mercury caps. This control option allows for a 70% effective removal for FBC units using a retrofit FF/ACI. Capital costs are assigned at $175 KW. The activated carbon injection rate is 2 lbs/MACF. Disposal cost of the reagent is the same as COHPAC on steam units at $1,200/ton. Fixed O&M costs are also the same at 1% of total capital.

APPENDIX A REFERENCES

Boward, 1997	W. Boward, et. al., "Particulate Control for Year 2000 and Beyond for Power Plants", Proceedings of the 1997 Mega-Symposium, Washington, DC
Bustard, 2004	Bustard, Jean, "Full-Scale Evaluation of the Injection of Activated Carbon for Mercury Control for Eastern and Western Coal", presentation to the Electric Utilities Environmental Conference, January, 2004, Tucson, AZ.
Chu, 2000	Chu, Paul, et. al., "An Assessment of Mercury Emissions from U.S. Coal-fired Powerplants", EPRI Report 100068, December, 2000.
Cichanowicz, 2004	Cichanowicz, J.E., "Why Are SCR Costs Still Rising", Power Magazine, April, 2004, Volume 148, No. 3.
Doptaka, 2003	P. Doptaka et. al., "Opportunities to Achieve Improved WFGD Performance and Economics", Proceedings of the EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium", May, 2003, Washington, DC
EPA, 2000a	"Controlling SO2 Emissions: A Review of Technologies", EPA Report EPA/600-R- 00-093, November, 2000.
EPA, 2000	Performance and Cost of Mercury Emission Control Technology Applications On Electric Utility Boilers, R.K. Srivastava et. al., September 2000, EPA-600/R-00-083.
EPA, 2001	Control of Mercury Emissions from Coal-fired Electric Utility Boilers: Interim Report, J.D. Kilgroe et. al., December 2001, EPA–600/R-01-109.
Froelich, 1995	Froelich, D. et. al., "Compliance Options for Phase 2 of the Clean Air Act Amendments of 1990 – A Look At Upgrading Existing FGD Systems", Proceedings of the 1995 SO2 Control Symposium", Miami, FL, EPRI TR-105258-V1, June 1995, Volume 1
Johnson, 2005	Johnson, D. et al., "Toxecon Retrofit for Mercury and Multipollutant Control", presentation to the 2005 NETL Mercury Review Control Technology Conference, July, 2005, Pittsburgh, PA

Hines, 2003	Hines, R., "A Fresh Look at SNCR", Proceedings of the EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium", May, 2003, Washington, DC.
Keeth, 1999	R. Keeth et. al.," Coal Utility Environmental Cost (CUECost) Workbook Users Manual", report for Environmental Protection Agency, EPA Contract 68—D7-0001.
Keeth, 2004	R. Keeth, Personal Communication with J. E. Cichanowicz, April, 2004.
Maller, 2003	G. Maller et. al., "Improving the Performance of Older FGD Systems", Proceedings of the EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium", May, 2003, Washington, DC.
Marano, 2006	Marano, M. et. al., "Estimating SCR Installation Costs", Power Magazine, January/February 2006.
Meserole, 2001	Meserole, Frank et. Al., "Predicted Costs of Mercury Control at Electric Utilities Using Sorbent Injection", Proceedings of the Mega-Symposium, Chicago, Ill, August 2001.
Moser, 1991	R. Moser et. al., "Overview On The Use of Additives In Wet FGD Systems", 1991 EPRI SO2 Control Symposium, Miami , FL.
Sargent & Lundy, 2003a	Sargent & Lundy, "Wet Flue Gas Desulfurization Technology Evaluation", Prepared for the National Lime Association, January, 2003
Sargent & Lundy, 2003b	Sargent & Lundy, "Dry Flue Gas Desulfurization Technology Evaluation", Prepared for the National Lime Association, September, 2002.

APPENDIX B

SUMMARY OF ASSUMPTIONS DEFINING HG CONTROL TECHNOLOGY PERFORMANCE AND COST FOR USE IN EVALUATING PROPOSED STATE HG RULES

SECTION B-1

INTRODUCTION

This document describes the series of assumptions defining the technical feasibility and cost of mercury control (Hg) options from coal-fired power plants, to be used in evaluating the impacts of the proposed State of Pennsylvania Hg control legislation.

Hg control technology status is perhaps one of the most controversial debates in environmental control capability in recent years. No fewer than 20 commercial-scale demonstrations have been conducted since 1997, and another 12 are planned that will be completed between 2006 and 2010. These demonstrations have showcased control technology availability and provided insight as to the degree of control effectiveness and cost.

The assumptions presented in this document reflect the feasibility and cost for commercial scale operation, for continuous 24x7 duty and over extended operating periods. Given the time-scale of utility equipment lifetime, the importance of reliability, and the extent of investment required, a detailed treatment is warranted.

For some application conditions, these Hg control assumptions directly adopt the results of commercial-scale demonstrations. For other application conditions, either the cost or performance is adjusted to reflect site-specific conditions for the unit, or the realities of continuous operation. Perhaps the most significant shortcoming is the preponderance of short-term data (e.g. measured in hours or 1-2 days) and operations, in contrast to extended operation of 6 months and more. Results of the sole demonstration that extended one year or the three that generated 30 days of operation are adopted in their entirety, for the site-specific conditions they reflect.

These assumptions describe (a) inherent Hg removal, as observed with existing plant equipment (Section B-2), (b) the performance and cost of conventional and halogenated activated carbon injection in ESPs (Section B-3), fabric filters (Section B-4), and dry flue gas desulfurization (FGD) process equipment (Section B-5). The calculation of "Hg cobenefits" from SCR and conventional wet FGD process equipment is addressed in Section B-6.

SECTION B-2

INHERENT REMOVAL AND BASELINE HG EMISSIONS

The first step in evaluating Hg control feasibility and cost is determining the inherent Hg removal provided by the exiting control technology arrangements.

Initial results from the ICR analysis conducted in 1999 have been evaluated by EPRI to establish a correlation between coal properties, environmental control equipment, and the removal and speciation of Hg in boiler flue gases (EPRI, 2000). Since these correlations were published, additional data has been derived and these relationships have been updated, not as a closed-form correlation but through "emissions modification factor" (EMFs) derived for a specific control device or combination of control devices. These "EMF" factors, shown in Table B.2-1, are identical to the recommendations forwarded by UARG to the EPA on January 3 in response to the NODA solicitation, for final comments on mercury controls. These EMF factors have been used by the project team in similar analyses.

Table B.2-1. EMF Recommendations

Control Configuration	Bituminous Coal	Sub-bituminous	Lignite
CS-ESP	0.64	0.97	1.0
CS-ESP/wet FGD	0.40	0.82	0.56
CS-ESP/dry FGD	0.60	0.80	1.0
SCR/CS-ESP/wet FGD	Per Section 6	Per Section 6	Per Section 6
SCR/CS-ESP/dry FGD	0.25	0.80	1.0
FF	0.25	0.35	1.0
FF/wet FGD	0.10	0.25	1.0
FF/dryFGD	0.10	0.85	0.56
SCR/FF-wetFGD	Per Section 6	Per Section 6	Per Section 6
SCR/FF-dryFGD	0.10	0.85	1.0
HS-ESP	1.0	1.0	1.0
HS-ESP/wetFGD	0.50	0.80	0.80
SCR/HS-ESP/wetFGD	0.15	0.80	0.80

Note: EMF = (1-Control Efficiency)

As noted in Table B2-1, the Hg removal provided by SCR NOx control in conjunction with wet, conventional FGD will be determined by the methodology described in Section B-5. This approach is adopted in lieu of an EMF as significant recent research has focused on improving the ability to predict Hg removal, based on coal chloride content (Chu, 2006).

The EPRI published correlations will be used to determine (a) Hg emissions from fluid bed units equipped with fabric filter particulate controls, and (b) the speciation of Hg between the oxidized and elemental forms. The correlations relating fluid bed Hg emissions are of the same form used in most ICR correlations:

Hg Removal (or percent elemental) = Multiplier * ln (coal Cl, ppm) + Constant

Table B.2-2 summarizes the multiplier and constant for the fluid bed boiler technology.

Table B.2-2. Summary of Factors in the FBC Correlation

Control Component	Multiplier	Constant
FBC FF	0.1394	0.1127

There are several special exceptions to the use of these correlations, based on field tests conducted by Illinois generators. Most significantly, a series of field tests dedicated to PRB-fired cyclone boilers showed that most units averaged an inherent Hg removal of 50%, with the exception of Dynegy Baldwin, which featured an inherent Hg removal of 80%. Accordingly, these values were used as inputs to the analysis.

SECTION B-3

ACTIVATED CARBON INJECTION (ACI) IN PM CONTROLS

The removal of Hg by injecting conventional and specially-treated (e.g. halogenated) activated carbon into particulate matter (PM) controls is addressed in this section.

B.3.1 Conventional ACI/ESPs

The assumptions defining Hg removal performance of activated carbon injection (ACI) into ESPs located on the both cold-side (ESPc) and hot-side (ESPh) ESPs depend on the concentration of flue gas SO3, the ESP SCA, and to a lesser extent, unit generating capacity. Table B.3-1 presents the assumed relationship (**in bold print**), and the specific reference of demonstration test data from which the assumption is derived (*in 10 pitch italic print*). Table B.3-1 summarizes the relationship between ACI and ESP, depending on coal type (e.g. PRB or eastern bituminous coal), for two ranges of ESP specific collecting area (SCA) and various generating capacities. Reference data is shown for PRB coals and one eastern bituminous application.

The results are assumed to depend on coal type, the size of the generating unit, and the ESP size (specific collecting area, or SCA) as follows:

Coal Type

PRB. Data for exclusive use of PRB is presented, and relevant references identified. The ability of conventional ACI to remove Hg is believed to be limited by a lack of halogens (Cl, Br).

PRB/Eastern Bituminous Blend. Data for the use of a PRB blend and eastern bituminous coal, with PRB the predominant constituent, may provide for improved Hg control. Eastern bituminous coal may introduce adequate chlorides to promote Hg oxidation, while the predominance of PRB and extremely alkaline ash minimizes the production of SO3 (which can interfere with carbon absorption). These assumptions assign a 10-15% improvement in Hg removal due to the use of an approximate 75/25 blend of PRB and eastern bituminous coal.

Exclusive Eastern Bituminous Coal. In the content of these assumptions, eastern bituminous coal is defined as such with at least 1% sulfur content. This level of sulfur is assumed necessary to generate the 4-6 ppm of SO3 that may be the threshold for impairing Hg removal.[7]

---

[7] Table B.3-1 assumptions consider Hg removal data with ACI from Brayton Point and Salem Harbor, due to extremely low sulfur coal, to reflect more a PRB mixture due to low sulfur content. Further, for both host plant equipment and process reasons, these demonstrations are considered of secondary relevance. This is because (a) Salem Harbor featured extremely high LOI, which elevated inherent Hg removal, and (b) Brayton Point employs a 2-stage ESP, allowing the second ESP to treat Hg in a high carbon/low ash environment.

Bituminous coals from sources with less than 1% are assumed to behave more like a PRB/eastern bit blend.

For higher sulfur coal, it is believed that flue gas SO3 will compete with Hg for active sites on the carbon surface, and degrade performance. Limited data exists defining the Hg removal with conventional activated carbon. Tests at Plant Daniel (Bustard, 2006), Lausche (Nelson, 2003), and Yates (Dombrowski, 2005) are cited. These sources suggest Hg removal varies widely. With the exception of the small units as reflected by Yates, a 60% Hg removal is adopted, assuming higher ACI rates and modest sorbent improvements are possible.

Consistent with the observation the flue gas SO3 will compete with Hg for absorption sites, a separate set of Hg removal assumptions will be adopted for units that employ SO3 conditioning. Based on commercial–scale testing conducted for an Illinois generator, Hg removal was limited for both conventional and halogenated sorbent. Table B.3-1 and B.3-2 will specify the details of these assumptions.

Generator Size, ESP SCA

In addition to coal type and blend, and the presence of flue gas SO3 conditioning, Hg removal results are assumed to depend on both ESP SCA, and generator size.

ESP SCA. Given that 70% of all ESPs in the U.S. feature an SCA less than 300 ft^2/1000 acfm (Slide #4 of Dombrowski, 2005), the predominance of large ESPs in the numerous demonstration units presents an optimistic case for the ability to inject activated carbon without inducing ESP opacity problems. It is notable that the sole small ESP tested (Yates at 170 SCA) did incur opacity problems; and even at the large SCA Monroe station anecdotal evidence of opacity problems were noted. Accordingly, the assumptions proposed for this study assign a limit on ACI performance for units <250 SCA, and further require such units to be upgraded by the addition of one field to achieve the projected Hg control requirement.

Generating Capacity. The ability to uniformly disperse sorbent throughout the entirely of a flue gas cross-section, necessary for high Hg removal, is assumed to increase with the size of the flue gas duct. This view is consistent with a global review of the various ACI demonstrations - among the highest Hg removal was noted at the smallest generating sites (e.g. St. Claire, Meramac) and among the lowest at the largest generating sites (Pleasant Prairie, Monroe). Although coal composition and SCA likely also play a role, given the information available to date it is not possible to exclude generating size. This concern is bolstered by release of results from CFD modeling of reagent injection systems that report the distribution of residence time in real systems can be only half that calculated for "plug flow" conditions.[8] Although these specific results for Brayton Point did not compromise performance, they do not allay concerns that sorbent mixing and distribution problems are independent of generating size.

These assumptions presume that all units equipped with low SCA ESPs – specifically those with an SCA less than 250 ft^2/kacfm - will require an extra field to sustain the same level

[8] Power Engineering, January 2006, page 13.

of carbon injection as larger ESPs. The capital cost will be defined by the analysis of Boward (1997), escalated to a 2006 dollar basis and including adjustments as defined by utility-specific studies for these modifications. Accordingly, the capital cost for this ESP upgrade will be \$35/kW for a 250 MW unit. The upgrade of a unit to 250 SCA will be required to derive the cited Hg removal. The capital cost of \$35/kW, as determined for a 250 MW unit, will be generalized to other generating capacities by a power-law relationship, using a 0.35-power scaling factor, described as follows;

$$\text{ESP Upgrade Cost (@ Capacity)} = 35 * (250/\text{Capacity})^{-0.35}$$

Table B.3-1 also presents results for the special case of units utilizing ESPs with SO3-based flue gas conditioning. As suggested during tests with simulated SO3 flue gas content (Bustard, 2006) and specifically for units with flue gas SO3 conditioning (Ameren, 2006a), the introduction of 3-5 ppm SO3 or more will limit Hg removal to a long-term value of 35% with conventional sorbent. Tests conducted by ADA-ES for Ameren suggest that the use of halogenated sorbents will increase the Hg removal to approximately 50%.

Table B.3-1. Summary of ACI/ESP Assumptions

Capital Cost ($/kW)	Capacity (Reference unit)	ESP (SCA)	Hg Removal, %	ACI Rate (lbs/MACF)	Comment
Note 1	**>500**	**>250**	**PRB: 75** **PRB/E. Bit: 75** **East Bit: 60** **All coals w/FGC: 35%**	**7** **6** **12** **5**	Total, include inherent calculated Hg removal as calculated per EPRI (2000)
Reference:	*Pleasant Prairie (600)*	*485*	*PRB: 60*	*10*	*PRB: Durham, 2003*
Reference:	*Monroe 785 (196)*	*285*	*75*	*6*	*PRB/E. Bit blend: Slide 29 of Sjostrom 2005 (AQV)*
Reference	*Labadie, 630*	*279/ FGC*	*PRB: 35*	*5*	*ADA-ES Report for Ameren*
Note 1	**250-500**	**>250**	**PRB: 80** **PRB/E. Bit: 80** **East Bit: 65** **All Coals w/FGC: 35%**	**6** **6** **8** **5**	*East Bit: defined by Slide #29 of Bustard (2006)*
Note 1	**25-249**	**>250**	**PRB: 85** **PRB/E. Bit: 85** **East Bit: 70** **All coals w/FGC: 35%**	**6** **6** **8** **5**	
	Meramec 140 (70)	*320*	*75*	*5*	*PRB. Slide 26 of Sjostrom 2005 (AQV)*
	St. Clair 160	*470*	*70*	*6*	*PRB/E. bit.*
	Lausche (18 MW); Daniel (500 MW)	*370*	*25*	*5*	*High S East Bit w/20 ppm SO3. Nelson, 2003, Figure 15. Also see slide 29, Bustard (2006)*
	Labadie, 630	*279/ FGC*	*PRB: 35*	*5*	*ADA-ES Report for Ameren*
Note 2	**>500**	**<250**	**PRB: 70** **PRB/E. Bit. : 70** **E. Bit: 60** **All coals w/FGC: 35%**	7 8 8 5	Small capacity, SCR assumed to compensate for PRB. Hg removed for East Bit capped at 60%.
	250-500	**<250**	**PRB: 75** **PRB/E. Bit. : 75** **E. Bit: 70** **All coals w/FGC: 35%**	7 8 8 5	
	<25-249	**<250**	**PRB: 80** **PRB/E. Bit: 80** **East. Bit: 75** **All coals w/FGC:**	7 8 8 5	

			35%		
Reference:	*Yates (100 MW)*	173	75	4	E. Bit: Dombrowski (2006), Slide #21.

1. Curve from Slide 30 of Bustard, 2006
2. Note 1 data and cost for 1 additional ESP field, per Gaikwad (1997) (Note: add $25/kW for capital, scaled from 250 MW).

B.3.2. Specially-Treated (Halogenated) ACI in ESP

Several field tests evaluating the feasibility of halogenated activated carbon injection (HACI) into both ESPs and fabric filters have been completed through July of 2005. The extent of this work – still lacking the desired long-term experience of 12 and 18 months believed necessary – is inadequate to fully characterize the use of halogenated sorbents. More significantly, all full-scale tests with HACI are on PRB or lignite coals, with no eastern bit coals planned for testing until the AEP Conesville station in 2006. Thus, Hg removal data is presented for PRB, with an adjustment implemented for the Plant Daniel tests showing the role of SO3 as reported by Bustard (2006). The data of Bustard (2006) suggest a compromise in Hg removal by 20-40% is incurred for only 6 ppm SO3; accordingly a 20% compromise is assumed contingent upon a 50% increase in AC injection rate.

Table B.3-2 summarizes the performance assumptions selected to reflect present technology status. The Hg removal rates and associated HACI rates are derived from three prominent demonstrations of HACI performance. Significantly, data from the 600 MW Monroe unit shows that 75-80% Hg removal was achieved, approximately the same as the value attained with conventional ACI. .Results from the 80 MW demonstration segment of the 160 MW St. Clair unit suggest 90% Hg removal is feasible. More significantly, 30 day continuous tests at St. Clair showed that 93% Hg removal was achieved, at 3 lbs/MBtu of B-PAC (Slide 5 of Landreuth, 2004). Data from the high sulfur coal –fired extremely small (18 MW) Lausche unit shows 70% Hg, and the authors cite this as evidence that excessive SO3 provides "challenging" process conditions for Hg removal, even for HACI, corroborating the data of Bustard (2006).

For halogenated ACI, Hg removal assumptions are presented for PRB, and adjusted for east bituminous coal.

Table B.3-2 also presents results for the special case of units utilizing ESPs with SO3-based flue gas conditioning. As suggested during tests with simulated SO3 flue gas content (Bustard, 2006) and specifically for units with flue gas SO3 conditioning (Ameren, 2006a), the introduction of 3-5 ppm SO3 or more will limit Hg removal to a long-term value of 50% with halogenated sorbent.

Table B.3-2. Summary of Chemically-Treated ACI Test Results

Capital Cost ($/kW)	Capacity (Reference unit)	ESP , (SCA)	Hg Removal	ACI Rate	Comment
Note 1	**>500**	**>250**	**PRB: 80** **PRB/E. Bit: 80** **East Bit: 60** **All coals w/FGC: 50%**	**4** **6** **6** **5**	1. Presumes short-term Monroe test results apply. 2. Assumes east bit coal derives 20% less Hg removal at 50% more AC, per Bustard (2006)
	Monroe 785 (196)	*285*	*PRB: 80-82 East bit correction from Plant Daniel data*		*80/20 PRB/E. Bit Blend: No increase in Hg removal. Sjostrom 2005a, Slide 28; East bit correction from slide 29 of Bustard 2006.*
Reference	*Labadie, 630*	*279/ FGC*	*PRB: 35*	*5*	*ADA-ES Report for Ameren*
Note 1	**250-500**	**>250**	**PRB: 85** **PRB/E. Bit: 85** **East Bit: 65** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Same as >500 MW
Note 1	**25-249**	**>250**	**PRB: 90** **PRB/E. Bit: 90** **East Bit: 70** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Smaller unit size, mixing distance improve performance
	Meramec (140/70)	*320*	*95*	*4*	*100% PRB: Darco LH. Short-term tests, PRB coal*
	DEC St. Claire (80)	*ESPc: 470*	*90%, at 3 lbs/MACF*	*3*	*80/20 PRB/E. bit Blend: Sorbent Technologies, 2005a 330 F ESP*
	Laushe (18)	*ESPc: 370*	*70*	*4*	*Nelson, 2003, high S East Bit. States high SO3 complicates removal*
Note 2	**>500**	**<250**	**PRB: 75** **PRB/E. Bit: 75** **East Bit: 60** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Assumes east bit coal derives 20% less Hg removal at 50% more AC, per Bustard (2006)
"	**250-500**	**<250**	**PRB: 80** **PRB/E. Bit: 80** **Eat Bit: 65** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Same
"	**25-249**	**<250**	**PRB: 85** **PRB/E. Bit: 85** **East Bit: 70**	**4** **6** **6**	Same

	All coals w/FGC: 50%	**5**

Note 1. Curve from Slide 30 of Bustard, 2006

Note 2. Include slide 30 (Bustard, 2006) and cost for 1 additional ESP field, per Gaikwad (1997) (add $25/kW for capital, scaled from 250 MW).

Based on the results in Table B.1-4, and similar to the case for conventional ACI, the performance of HACI is assumed to depend on both generating capacity and ESP SCA.

These assumptions acknowledge, and are consistent with, two 30–day tests of HACI showing Hg removal exceeding 90%. Specifically, both the St. Claire and Meramac units achieved in excess of 90% Hg removal for 3-4 lbs/MACF. The assumptions acknowledge and reflect this data for small capacity, high ESP SCA units.

The delivered cost for HACI is selected based on the following observations:

- In 2003, Sorbent Technologies presented data for their "Type A" sorbent, later revealed to be B-Pac. In 2003 Sorbent Technologies cited this reagent would be "conservatively" estimated as available for $0.60/lb.

- In 2004-2006, Sorbent Technologies states this same reagent will be available for $0.75/lb.

- In 2006, ADA-ES representatives state Darco LH is available for $0.85/lb at the manufacturing site, without delivery charge. This anticipated charge for delivery to Illinois may be $0.10-0.15/lb, increasing the total delivered cost to $0.95-1.00 $/lb.

This gradual escalation in prices has been witnessed prior to demand of the sorbent, which could be expected with broad deployment of HACI. Consequently, the average sorbent cost assumed for an Illinois adoption of strict Hg controls is $1.15/lb.

3.3. The Special Case of Hot-Side ESPs

The special case of reducing Hg emissions from units equipped with hot-side ESPs is been the subject of demonstrations of HACI by several suppliers. The hot-side ESP, due to higher operating temperature, can impair the performance of both conventional and halogenated sorbents.

Table B.3-3 summarizes the assumptions defining HACI performance for hot-side units, based on results from Duke Power's Cliffside and Buck station. The proposed Hg performance levels are assumed invariant with generating size and ESP SCA, as there is no data over which to generalize performance to larger capacities of smaller ESPs. For all generating capacities, Hg removal of 50% at 3 lbs/MBtu will be assumed.

Table B.3-3. HACI: Hot-Side ESPs

Capital Cost ($/kW)	Unit Capacity (Reference unit)	ESP , per Specific Collecting Area (SCA)	Hg Removal	ACI Rate	Comment
Note 1	**all**	**all**	**50**	**3**	Conclusion of Sorbent Technologies, Slide #29 of Nelson (2005)
Duke Cliffside	*40 MW ESP*	*ESPh: 240*	*60-75%*	*5*	*Short-term results: Slide 23 of Nelson (2005)*
Duke Buck	*140 (70)*	*ESPh: 240*	*64%*	*7*	*E. Bit Low S coal: Nelson (2005) Slide 25*

Of course, units equipped with hot-side ESPs can be retrofit with a fabric filter to provide a TOXECON process environment, as will be described in a subsequent section.

B.3-3. Fly Ash Revenue Loss

One additional element of the calculation is to account for the potential loss of fly ash sale due to higher carbon content. For Pennsylvania will assume that 30% of the ash generated is presently sold, and all of this will not be marketable, and further a combined charge of $28/ton will be assessed for additional disposal and loss of ash revenue.

SECTION B-4

ACI/FABRIC FILTER

Either conventional or halogenated activated carbon can be injected into a fabric filter, arranged either to augment PM removal in a COHPAC application, or as the sole particulate control device.

B.4.1. COHPAC: Conventional Activated Carbon

The assumptions defining Hg removal by conventional ACI on fabric filters for particulate control has been explored in most depth on Alabama Power's Gaston station, which is the sole reference for performance used in this study.

The ACI/FF demonstration at Gaston is the most advanced commercial application of ACI. A Phase II long-term test program has been completed, with up to four months of continuous data. These results showed that the long-term average of Hg removal was 86%, at an ACI rate of 1.5 lbs/MBtu. Special diagnostic tests at the end of the program suggested that greater than 90% Hg removal was possible, at a lower air/cloth ratio. However, these results were obtained from test periods that averaged several hours each. Given the variation in coal composition and uncertainties in process measurements, we adopted the 86% level demonstrated at Gaston.

Table B.4-1. Hg Performance Achieved by ACI/FF

Capital Cost ($/kW)	Unit Capacity (Reference unit)	FF Design, per air/cloth ratio	Hg Removal	ACI Rate	Comment
Note 3	all	all	86	1.5	Based on Phase II, long-term testing from Gaston
	Gaston, 170 MW		80-90	1.5	Gaston is considered the most significant reference point.

Note 3. FF capital cost scaled from data available from the Presque Isle 3x90 MW DOE Demonstration

Why Is Hg Removal Not Higher? Gaston tests noted that load limits were imposed by flue gas pressure drop at the design air/cloth ratio. However, lower flue gas flow rate to decrease air/cloth ratio to approximately 5 ft/m allowed 90% Hg removal. These were short tem tests and although encouraging provide inadequate basis for certifying 90% Hg removal long-term.

It should be noted that Hg removal measured in a fabric filter following a dry FGD process is not considered representative of application for solely particulate removal. The most significant difference is the temperature of FF operation, and (depending on where the AC is injected) the dispersal of AC within the flue gas. AC injected prior to the dry scrubber vessel will derive the benefit of the high energy mixing and dispersal environment of the dry scrubber vessel, in which 4-6 second residence time is provided for contacting. The injection of ACI into a FF – either following a hot-side or cold-side ESP – will not offer the same degree of contacting, and thus process conditions may not be comparable.

Capital costs for retrofit of a fabric filter to an ESP are based on the recent design studies conducted for the WE Energies TOXECON retrofit to Presque Isle Power Station (Johnson, 2005) and other Midwestern generators. The Presque Isle design study conducted to support this project shows the capital cost for three 90 MW units will be $34 M, equivalent to $120/kW. Further details of the fabric filter or COHPAC capital cost is presented in the companion document for CAIR compliance (see Figure A-9).

Regarding solid byproduct management, the COHPAC application collects injected activated carbon after fly ash has been removed, so only the Hg-laden carbon must be disposed of. This material is assumed to require lined landfill and to incur a disposal cost of $1,200/ton.

B.4.2. COHPAC: Halogenated Activated Carbon

As of February 2006, there is no data describing Hg removal from halogenated AC within a FF operated solely for particulate removal (and thus not following a dry FGD). However, it is anticipated that based on Gaston results, up to 1.5 lbs/MACF can be injected into a COHPAC-type environment without incurring significant operating problems. This level of carbon injection is assumed adequate to deliver 90% Hg removal.

Significantly, the 3x90 MW demonstration of FF following an ESP (Toxecon) funded by DOE is intended to demonstration that "at least 90% Hg removal" is available.

Table B.4-2. Halogenated AC with FF

Capital Cost ($/kW)	Capacity (Reference unit)	FF Design, per air/cloth ratio	Hg Removal	ACI Rate	Comment
Note 3	all	all	90	1.0	Based on Phase II, long-term testing from Gaston, with reduced ACI rate to reflect HAC reactivity.
	Presque Isle		TBD per DOE demo	TBD	Presque Isle will be considered the most significant reference point.

1. Curve from Slide 30 of Bustard, 2006

Why Is Hg Removal Not Higher? Data from several SDA/FF-equipped units shows HACI derives greater than 90% Hg removal. However, these process conditions reflect (a) lower FF temperature, due to humidification by the SDA vessel, and (b) a high degree of dispersion of reagent.

The lack of commercial confidence by equipment and process suppliers is evidenced by the fact that DOE has directed $24 M into the Presque Isle Toxecon II Demonstration project, for the explicit objective to "demonstrate at least 90% Hg reduction" (Michaud, 2005). The complete commercial availability of HACI within a FF at 90% Hg would not require DOE cofunding for risk mitigation, testing, and evaluation of process impacts.

B.4.3. Fabric Filter As Sole PM Removal

Some units are equipped with a fabric filter in lieu of the ESP as the sole source of PM removal. Either conventional or halogenated activated carbon can be injected for Hg removal.

As there is no experience directly addressing this application, Hg removal data from the Gaston COHPAC demonstration is assumed valid. Accordingly, for conventional ACI, 86% Hg removal is assumed achievable at 1.5 lbs/MACF, and for halogenated ACI 90% Hg is assumed achievable at 1.0 lbs/MACF.

The significant difference in calculating the incurred cost is that unlike for COHPAC, where fly ash is captured separately and not contaminated by carbon, the fly ash collected with this application is contaminated by carbon. Thus, solid byproduct managements cost are identical to that incurred for ACI within an ESP, as described in Section B.3.3.

SECTION B-5

CARBON INJECTION: SPRAY DRYER ABSORBER (SDA)/FF

This section addresses the injection of both conventional and halogenated AC into a SDA/FF, designed for combined SO2 and particulate removal, for Hg removal. Conventional and halogenated AC are treated separately

B.5.1. Conventional AC/I w SDA/FF

The use of conventional AC into a SDA/FF can derive Hg removal, well above the baseline inherent Hg removal levels.

Table B.5-1. Hg Removal in Spray Dryer Absorber/PM, with Conventional ACI

Capital Cost ($/kW)	Capacity (Referenc . e unit)	PM Collector, Design	Hg Removal (%)	ACI Rate	Comment
Note 1	**all**	**FF**	**75%**	**5**	Lower level selected to account for variability
Reference:	*Sunflower/ Holcomb*		*80*	*3*	*PRB: Sjostrom, (2005a) Slide #21*
	Great River Energy/ Stanton U10		*75*	*7*	*Stanton U10 (Sjostrom, 2005a, Slide 21*
Note 1	**all**	**ESP**	**45**	**6**	
Reference:	*Basin Electric/ Laramie River*	*599 SCA*	*45*	*6*	*Laramie River (Sjostrom (2005a) Slide #23*

1. Curve from Slide 30 of Bustard, 2006

The results of a recent full-scale trial at Sunflower Electric's Holcomb Station (Sjostrom, 2005a) suggest the use of both conventional activated carbon, in this case Norit DARCO Hg when injected preceding the dry scrubber, can effect significant Hg removal. Short-term tests (2-3 hours) showed Hg removal higher than 90% was achievable at 6 lbs/MACF (See Slide 21 of Sjostrom, 2005a). Previously, Sjostrom (2003) reported that ACI with the dry FGD at Great River Electric's Stanton unit produced Hg removal of 65%, at an ACI of 5 lbs/MACF. None of these units are commercially operating, thus an average is used to assign Hg removal and ACI rate. Specifically, we propose to specify 70 % Hg removal from a dry FGD process on either lignite or subbituminous coal is attainable, with an ACI rate of 6 lbs/MACF. This assumption provides for some degree of additional Hg control beyond the inherent calculated level, but recognizes the unproven nature of the data.

B.5.2. Halogenated ACI with SDA/FF

The use of halogenated sorbent has been explored on these and similar units. As reported by Sjostrom (2005a, 2005b) both Darco Hg and B-Pac specially-treated, halogenated sorbents were evaluated in a spray dryer absorber following by a fabric filter or ESP. Results from short-term tests showed 90% Hg removal at 1.5 lbs/MACF, and for B-Pac exceeding 90% at 2 lbs/MACF. More significantly, 30 days tests at Holcomb (Sjostrom, 2005a (slide 21) and Sjostrom, 2005b (slide 23) reported greater than 90% Hg removal at 1.3 lbs/MBtu.

Table B.5-2. Hg Removal in SDA/PM, with Halogenated Sorbents

Capital Cost ($/kW)	Host Unit/Test Capacity (MW)	PM Collect or, Design	Sorbent	Hg Removal	ACI Rate	Comment
Note 1	**all**	**FF**	**HACI**	**90%**	**1.5**	Per commercial-scale tests
Reference:	*Sunflower/ Holcomb:*		*Darco Hg*	*90*	*1.5*	*Holcomb (Sjostrom, 2005a) (NETL, slide 21)*
	Great River Energy/ Stanton U10		*Darco Hg*	*90*	*1.5*	*Stanton U10 (Sjostrom, 2005a, slide 21*
			B-Pac	*90*	*1.5*	*Stanton U10 (Sjostrom, 2005a, slide 21*
Note 1	**all**	**ESP**	**HACI**	**90%**	**6.5**	
	Basin Electric/ Laramie River (540/140)	*ESP, 599 SCA*	*Darco Hg*	*94*	*6.5*	*Laramie River (Sjostrom, 2005a) slide 26*

1. Curve from Slide 30 of Bustard, 2006

Unlike the case for ACI into an ESP or FF, there is no solid waste impact of using either conventional or halogenated AC.

B.5.3. Retrofit Application of SDA/FF

The application of a SDA/FF to an existing until will entail retrofit following an existing ESP. In order to preserve fly ash markets, it is likely the existing ESP will not be de-energized, and operation retained. This unit will be expected to continue to deliver the inherent Hg removal as projected by the EMFs in Section 1. Accordingly, the SDA/FF Hg removal cited in this section will provide the stated Hg removal in addition to inherent values calculated for the ESP.

SECTION B-6

SCR AND FGD HG REMOVAL

The presence of FGD will remove almost all Hg oxidized into the oxidized state, and SCR can increase the oxidation thus improving the net removal. The assumptions describing the Hg removal are summarized in this section.

B.6.1. The Role of FGD

Conventional wet FGD is assumed to remove 90% of the oxidized Hg entering the process, based on results from field tests with highly oxidized FGD slurry (EPA, 2005) This magnitude accounts for the small amount of Hg re-emission.

Evaluation of compliance strategies will calculate the speciation of Hg into Hg++, and assume 90% is removed in a conventional wet FGD limestone, forced oxidation system. The use of an FGD other than forced oxidation limestone based, such as a lime or magnesium lime system, will be assigned a 70% Hg removal.

B.6.2. The Role of SCR

SCR NOx control is observed to increase the level of oxidation of Hg; the recent data of Chu (2006) and shown in Figure B.6-1 summarizes a relationship between the average increase in Hg oxidation for various SCR installations as a function of coal chloride content.

The approach for calculating the Hg removed by SCR, for the case of either an ESP or fabric filter used for PM control, and followed by wet FGD is described as follows:

Estimate Hg Oxidation Due to SCR. If SCR is present, the Hg oxidation rate will be increased to the value determined by a curve fit of the relationship between Hg oxidation and coal chloride content, per Chu (2006).

Oxidized Hg Removed. It will be assumed ninety percent of the Hg in the oxidized state is removed by the FGD process. If SCR is not employed, the oxidized Hg will be determined from the ICR correlations as published by EPRI (2000).

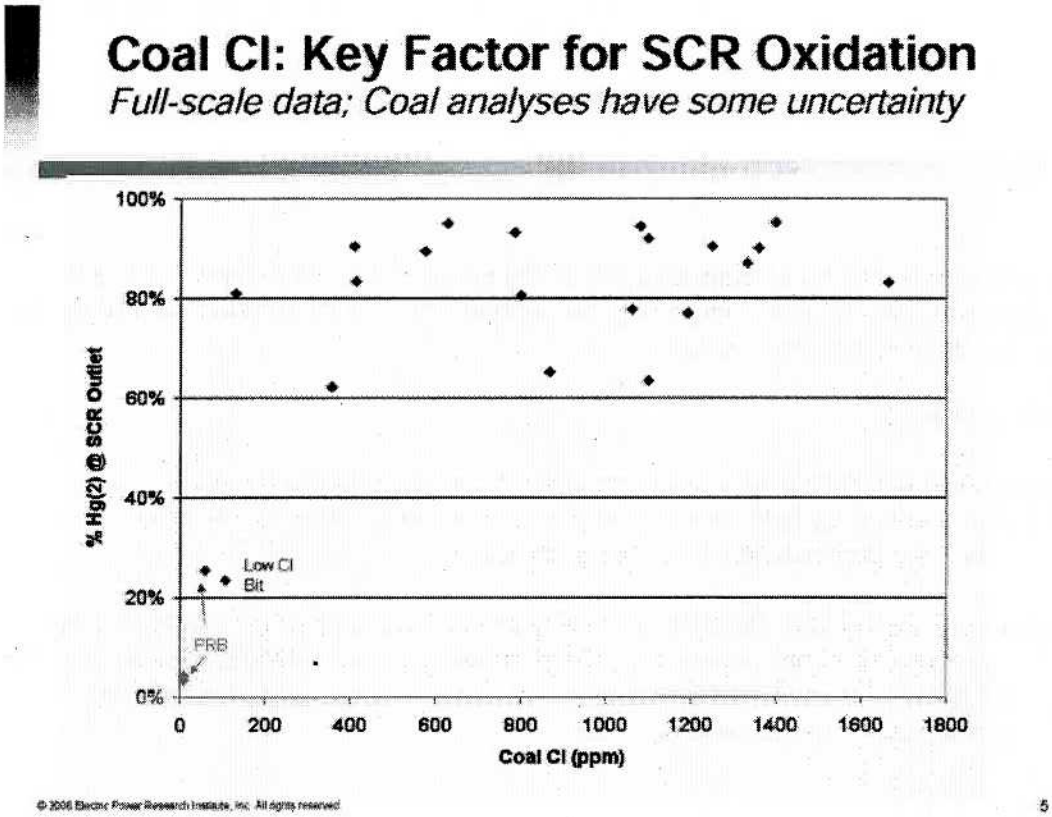


Figure B.6-1. Relationship Between Hg Oxidation and Coal Cl Content (Chu, 2006)

SECTION B-7

FLUID BED UNITS: ACI/FABRIC FILTER (COHPAC/TOXECON)

An aggressive mercury control option could be applied to FBC units to meet extreme mercury caps. This control option allows for an effective removal between 70 and 87 percent for FBC units using a retrofit FF/ACI. Capital costs are assigned to be $175 kW for these relatively small units (<100 MW), as derived from the $125/kW capital estimate from the Presque Isle 270 MW demonstration. The activated carbon injection rate is 2 lbs/MACF. Disposal cost of the reagent is the same as COHPAC on steam units at $1,200/ton. Fixed O&M costs are also the same at 1% of total capital.

REFERENCES

Boward, 1997	W. Boward, et. al., "Particulate Control for Year 2000 and Beyond for Power Plants", Proceedings of the 1997 Mega-Symposium, Washington, DC.
Bustard, 2004	Bustard, Jean, "Full-Scale Evaluation of the Injection of Activated Carbon for Mercury Control for Eastern and Western Coal", presentation to the Electric Utilities Environmental Conference, January, 2004, Tucson, AZ.
Bustard, 2006	Bustard, J., "Developing a Fleet-wide Strategy For Mercury Measurement and Control", Presentation to the Mercury Workshop at 2006 EUEC, Tucson, AZ, January 22, 2006.
Chu, 2000	Chu, Paul, et. al., "An Assessment of Mercury Emissions from U.S. Coal-fired Powerplants", EPRI Report 100068, December, 2000.
Dombrowski, 2005	Dombrowski, K. et. al., "Sorbent Injection for Small ESP Mercury Control in Bituminous Coal Flue Gas", presentation to the DOE/NETL Mercury Control Review Meeting, July, 2005.
EPA, 2001	Control of Mercury Emissions from Coal-fired Electric Utility Boilers: Interim Report, J.D. Kilgroe et. al., December 2001, EPA–600/R-01-109.
EPA, 2005	EPA,"Control of Mercury Emissions From Coal-fired Utility Boilers: An Update", Air Pollution Prevention and Control Division, National Risk Management Laboratory, Office of Research and Development, February, 2005.
Johnson, 2005	Johnson, D. et al., "Toxecon Retrofit for Mercury and Multipollutant Control", 2005 NETL Mercury Review Control Technology Conference, July, 2005, Pittsburgh, PA
Landeruth, 2004	Landeruth, R. et. a.l., "Full-Scale B-PAC Mercury control With Bituminous, Subbituminous, Lignite, and Blended Coals With Cold-Side ESPs, Fabric Filters, and Hot-Side ESPs", presented at the Eight EUEC, Tucson, AZ.
Nelson, 2004	Nelson, S. et. al., "Mercury Sorption Results at the Lausche Plant", Proceedings of the EPRI-DOE-EPA 2003 Mega-Symposium, May, 2003, Washington, DC.
Nelson, 2005	Nelson, S., "Advanced Utility Mercury-Field Sorbent Field-Testing Program", Presentation to the DOE NETL Contractors Conference", July, 2005, Pittsburgh, PA.
Sjostrom, 2005a	Sjostrom, S., Evaluation of Sorbent Injection for Mercury Control", DOE NETL Contractors conference, July, 2005, Pittsburgh, PA.
Sjostrom, 2005b	Sjostrom, S., "Full-Scale Evaluations of Mercury Control for Units Firing PRB Coal,", Air quality V conference, September, 2005, Alexandria, VA.

Sorbent Technologies, 2005a Update on Sorbent-Based Mercury Control in Hot-Side Environments", downloaded from Sorbent Technologies website, January, 2006.