Preliminary Cost Estimate of Activated Carbon Injection for Controlling Mercury Emissions from an Un-Scrubbed 500 MW Coal-Fired Power Plant

Final Report

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Innovations for Existing Plants Program

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DISCLAIMER

I. EXECUTIVE SUMMARY

Mercury regulation for the electric utility industry appears to be a near-term certainty. However, the specific compliance method or required level of control has yet to be determined. Currently, the U.S. Environmental Protection Agency (EPA) is in the process of developing source-specific Maximum Achievable Control Technology (MACT) mercury regulations for coal-fired utility boilers. In parallel with the MACT process, several multi-pollutant legislative acts have been proposed in recent Congressional sessions, offering alternative approaches to utility mercury regulation.

The development of a mercury emission regulation requires an understanding of the cost and performance of available control technologies. The mercury capture performance of existing air pollution control (APC) technologies for particulate matter, SO_2 and NOx (as a co-benefit) has been a subject of significant study. Currently, no single technology can cost-effectively provide add-on mercury control for all generating configurations or all fuel types. Activated carbon injection is the most mature mercury control technology and recent full-scale field testing, sponsored by the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL), have provided much needed cost and performance data for a limited number of coals and APC configurations.

This report develops "study level" costs (estimated accuracy of +/- 30%) for mercury control using activated carbon injection at representative 500 MW bituminous- and subbituminous-fired power plant units equipped with an existing cold side ESP (CS-ESP). Costs are estimated for activated carbon injection (ACI) into the existing CS-ESP, as well as the compact hybrid particulate collector (COHPAC™) configuration (ACI into a fabric filter (FF) retrofitted downstream of the existing CS-ESP).[1] The cost estimates are developed for equipment designed to achieve mercury control at low (50%), mid-range (60-70%), and high (90%) levels. It is important to note that the costs developed here are based on the current state of knowledge and understanding of carbon injection technology at three full-scale coal-fired utility boilers resulting from testing conducted over a relatively short duration, usually on the order of one or two weeks. Currently, several activities are being conducted under DOE/NETL's recent mercury solicitation as well as a long-term full scale demonstration funded under DOE/Fossil Energy's Clean Coal Power Initiative. These activities will provide additional operational and economic data to further refine these types of estimates and perhaps more importantly demonstrate long term performance capabilities as well as overall balance-of-plant impacts of ACI technology.

Estimates of the costs (current 2003$) of ACI for mercury control were developed based on capital requirements in terms of unit capacity ($/kW), incremental increase in cost of electricity (COE, mills/kWh), and in terms of the incremental cost of mercury removal ($/pound Hg removed). It is important to understand that these costs can vary significantly due to underlying economic and performance assumptions, including the assumed co-benefit mercury control of existing pollution control devices as well as coal mercury content. For this analysis, costs were developed for the representative 500 MW unit with co-benefit mercury control and coal mercury content based on information gathered during EPA's mercury Information Collection Request (ICR). Because all costs developed are constrained by the definition of the representative unit,

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[1] COHPAC™ as well as the injection of sorbent upstream of a fabric filter baghouse for air toxic control (TOXECON™) are technologies licensed by the Electric Power Research Institute (EPRI).

the use of different, basic assumptions than those used for the estimates provided here could result in significantly different results. This fact is perhaps most important when considering the incremental cost of control. Because the methodology developed here assumes that the required sorbent injection rate is dependent on flue gas flow rate and completely independent of flue gas mercury concentration, the coal mercury content can have a large impact on the incremental cost of mercury control when presented on a dollar per pound mercury removed basis. A sensitivity analysis indicates that the incremental cost of mercury control can vary by more than a factor of six for mercury contents typical of the coals used for this analysis.

For both bituminous- and subbituminous-fired units, capital costs are estimated to range from approximately $2/kW to $57/kW, the large range being attributed to the capital component of the FF retrofit for the COHPAC™ configuration. First year operating and maintenance (O&M) costs, exclusive of any fly ash impacts, are estimated to range from $931,000 to $15,645,000, with the primary cost components being sorbent consumption and FF O&M. The upper end of the O&M range accounts for a case of 90% mercury capture via a very high ACI rate for a bituminous-fired unit with an existing CS-ESP. The incremental increase in COE for possible retrofit configurations is estimated to range from 0.37 mills/kWh to 5.72 mills/kWh. Because many units market their fly ash, and therefore may have added revenue and avoided disposal costs, the impact of carbon injection on fly ash sales and disposal was also considered. When fly ash sales are negatively impacted and combined lost revenue and added disposal costs are included, the COE increase is estimated to range from 1.82 mills/kWh to 8.14 mills/kWh.

These cost estimates show that the economics of mercury control via ACI can be strongly influenced by a number of key components. The three most significant cost components are:

- Sorbent consumption
- By-product management and disposal
- Capital and operating costs associated with a new pulse-jet FF for carbon capture downstream of an ESP (ACI/COHPAC)

Additional factors that can influence the economics of mercury control include, but are not limited to: economic/financial assumptions, process factors (additional or extended outages, etc.), and required modifications to existing equipment.

The incremental cost of mercury control for this analysis, excluding impact to fly ash sales and disposal practices, is estimated to range from $33,000/lb mercury removed to $131,000/lb mercury removed for the bituminous-fired unit and from approximately $18,000/lb mercury removed to $55,000/lb mercury removed for the subbituminous-fired unit. The upper end of the bituminous range includes the 90% mercury capture case via a very high ACI injection rate for a unit with an existing CS-ESP. When fly ash sales and added disposal costs are included, the incremental cost of mercury control is estimated to range from $49,000/lb mercury removed to $246,000/lb mercury removed for the bituminous-fired unit and from $40,000/lb mercury removed to $80,000/lb mercury removed for the subbituminous-fired unit.

Results of this analysis indicate that, from an incremental cost perspective, mercury control at subbituminous-fired units appear to be more "cost-effective" than at bituminous-fired units. This is because of the higher incremental mercury removal attributed to ACI at a subbituminous-fired unit due to the assumption of zero co-benefit mercury capture by the existing CS-ESP. A CS-ESP at a bituminous-fired unit is assumed to capture 36% of the mercury exiting the boiler, and therefore less incremental mercury removal is attributed to ACI than for the subbituminous-fired unit.

While mercury control at coal-fired utility boilers using activated carbon injection appears to be technologically feasible, many uncertainties continue to exist. Among those include the demonstration of consistent, long-term performance of ACI for mercury control as well as impact to overall plant operations. Additionally, necessary demonstration of ACI mercury control for a variety of coals both within a coal rank and across coal ranks is necessary to accurately assess the ability to implement ACI technology throughout the existing fleet of coal-fired utility boilers. Furthermore, additional understanding of the mechanisms that control mercury capture using ACI, as well as refined methods of flue-gas mercury measurements will provide additional knowledge for efficient application of ACI technology as well as provide opportunities to lower the cost of mercury control by potentially facilitating the development of lower cost sorbent technologies.

II. INTRODUCTION

The regulation of mercury emissions from coal-fired utility boilers appears to be a near-term certainty, either as a MACT regulation for hazardous air pollutants through the existing Clean Air Act (Title III Section 112) or by regulations that may result from any of the mercury specific and multi-pollutant legislation proposed in the current session of Congress.

To insure that effective pollution control strategies are available for the existing fleet of coal-fired utility boilers, DOE/NETL is carrying out comprehensive, integrated research and development (R&D) as part of the Office of Fossil Energy's Innovations for Existing Plants (IEP) program. The program encompasses both in-house and contracted research focused on advanced, low-cost environmental control systems and ancillary science and technologies that can help the existing fleet of coal-based power plants meet current and future environmental requirements. The program also provides high-quality scientific information on present and emerging environmental issues for use in regulatory and policy decision-making.

The IEP portfolio includes bench-scale through field-scale R&D related to the control of mercury, NOx, particulate matter, and acid gas emissions from power plants, as well as research in the area of ambient air quality, atmospheric chemistry, and solid by-products. Furthermore, the program recognizes the importance of emerging water-related issues and their relationship with reliable and efficient power plant operations. Partnership and collaboration with industry, Federal and state agencies, research organizations, academia, and non-government organizations are key to the success of the program.

The mercury control technology portion of the IEP program includes a short-term goal to develop mercury control technologies that achieve 50 to 70% mercury capture at three-quarters (or less) of the current estimated costs for powdered activated carbon injection.[2] These technologies should be ready for commercial demonstration by 2005 for bituminous coals and by 2007 for low-rank coals. The IEP program also includes a long-term goal to develop advanced mercury control technologies to achieve 90% or greater capture at one-half to three-quarters the cost of existing technology and would be ready for commercial demonstration by 2010.

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[2] Baseline cost estimates for PAC technology are in the range of $50,000 to $70,000 per pound mercury removal.

Large-Scale Field-Testing of Sorbent Injection Technology

Laboratory-, bench-, and pilot-scale studies have shown that sorbent injection (e.g., activated carbon) could be an effective approach for the control of mercury emissions from coal-fired power plants. The studies also suggested that lowering the flue gas temperature using water-spray cooling might aid mercury adsorption and reduce sorbent injection requirements. To more fully evaluate the potential of sorbent injection as a mercury control option, large-scale field-testing was conducted in 2001-2002.

Through research funded by DOE/NETL, ADA Environmental Solutions (ADA-ES) evaluated the effectiveness of powdered activated carbon (AC) injection at four coal-fired electric utility boilers. Participants in the program included EPRI, EPA, Alabama Power Company, PG&E National Energy Group, and We Energies, along with several others. Testing was carried out sequentially at the four host sites described in Table 1.

Table 1. Description of Units Participating in Sorbent Injection Testing

Utility Company	Plant	Coal Rank	APCD Configuration	Date Test Completed
Alabama Power	E.C. Gaston Unit 3	Low sulfur bituminous	Hot-side ESP and FF (COHPAC™)	April 2001
We Energies	Pleasant Prairie Unit 2	Powder River Basin	Cold-side ESP	November 2001
PG&E	Brayton Point Unit 1	Low sulfur bituminous	Cold-side ESP	August 2002
PG&E	Salem Harbor Unit 1	Low sulfur bituminous	Cold-side ESP and SNCR	November 2002

The testing at each plant included parametric tests using several commercially available powdered AC products at various feed rates and operating conditions followed by a one- to two-week, long-term test with a powdered AC selected from the parametric testing. Results of the testing have demonstrated that mercury control via activated carbon injection is technologically feasible for both bituminous and subbituminous coals. Full-scale testing at both Gaston and Pleasant Prairie showed no mercury capture improvements for spray cooling.

ACI parameters are dependent upon desired mercury control level and vary for specific particulate control device(s) installed. Figure 1 provides ACI data for the first three units tested. Although not tested at full-scale, ACI parameters for subbituminous-fired units equipped with a FF are also included, being obtained from an ADA presentation of EPRI pilot scale data.[3]

Figure 1 illustrates the influence that the particulate control device can have on carbon requirements for mercury control, as seen by significantly higher mercury capture achieved at lower carbon injection rates for the FF curves when compared to the ESP curves.

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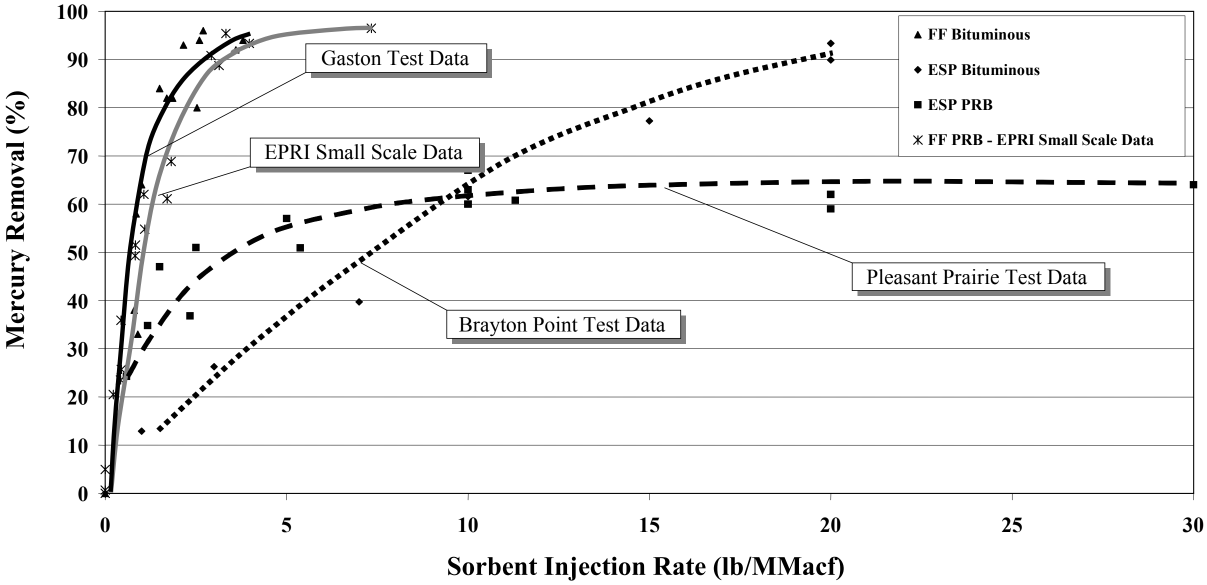
[3] Durham, Michael D. ***Results from Four Full-Scale Field Tests of ACI for Control of Mercury Emissions***, Presentation to the Utility MACT Working Group March 4, 2003 Washington D.C.

Figure 1. Full-Scale ACI Testing Data



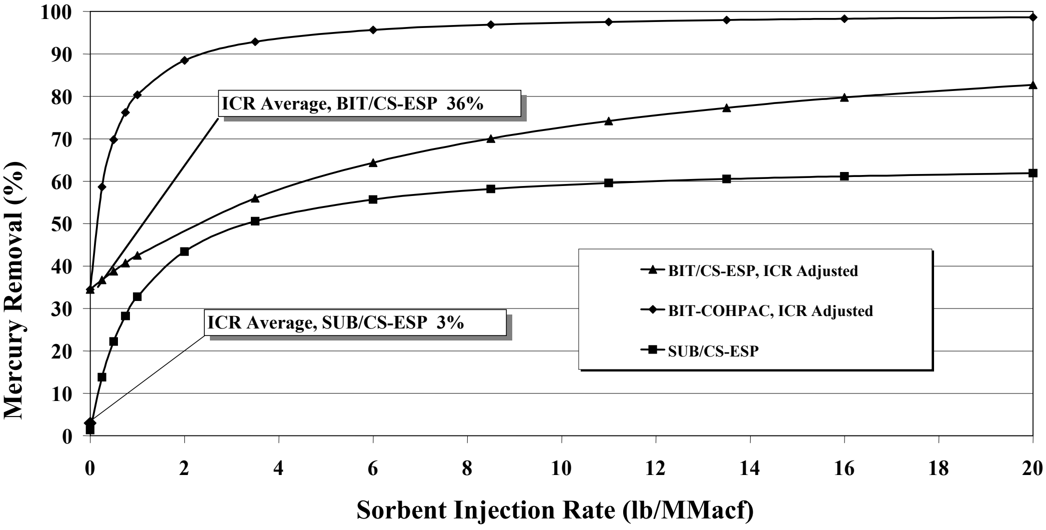
The fundamental difference between the FF and the ESP is the filter cake that coats the bags in the FF. The existence of the filter cake allows for improved gas contact with the carbon sorbent, which is assumed responsible for the higher mercury capture observed at lower carbon injection rates. Furthermore, Figure 1 also illustrates that carbon injection capture efficiency may also be fuel-rank specific, as can be seen in both the shape and the maximum capture observed in the ESP data for PRB-fired units when compared to the ESP data for the bituminous-fired unit. Based on the full-scale testing, it appears that higher levels of mercury control via ACI can be achieved for bituminous coals than are possible for low-rank coals. Although not included here, it is generally assumed that lignites will also behave more like subbituminous coals, although that has yet to be proven at full-scale. Currently, UNDEERC, through a DOE/NETL funded project, has completed bench- and pilot-scale testing of ACI for lignite-fired units. A field demonstration is planned at a yet to be determined location, with testing expected to be complete in 2004.

It should be noted that the ACI data for Brayton Point represents mercury reduction across the second in a series of two ESPs. This fact can help explain the low mercury capture at low injection rates which does not agree with either ESP average mercury capture without ACI for the ICR bituminous CS-ESP bin (36%) or the average performance of Brayton Point Unit 1 in the ICR database (28%). It is likely that the fly ash captured in the first ESP contributed to some mercury reduction exclusive of the capture due to AC injected upstream of the second ESP. An adjusted curve for Brayton Point was developed to include the co-benefit mercury capture of the existing CS-ESP and therefore allows development of ACI curves for overall mercury reduction based on mercury input to the boiler. Additionally, the FF data for Gaston represents AC injected into an existing COHPAC™ system configured with an upstream hot-side ESP. An adjusted curve was also developed to represent the addition of a FF to an existing CS-ESP, which may be retrofitted to achieve high (≥90% reduction) levels of mercury control. A more detailed discussion of the configuration of the individual field-tested units, as well as the adjustment for co-benefit mercury capture, is included in the appendix of this report.

III. TASK REQUIREMENTS

Cost and performance data from the full-scale testing results were reviewed and mercury control cost estimates were developed for representative 500 MW coal-fired units burning either West Virginia low-sulfur bituminous coal or Powder River Basin low-sulfur subbituminous coal. ACI injection curves were developed by use of non-linear regression of full-scale ADA data, while adjusting to conform to ICR results where necessary.[4] Figure 2 represents the adjusted regression curves for mercury reduction as a function of AC injection rate. AC injection requirements for a subbituminous-fired unit equipped with the ACI/COHPAC configuration were estimated based on the EPRI data included in Figure 1. Based on the full-scale tests, spray cooling is not considered effective and is therefore not included as a beneficial adjunct to ACI.

Figure 2. Non-linear Regression Fits for ACI



Because ACI co-benefit mercury capture is strongly dependent on the unit configuration, including various APCDs installed for control of non-mercury pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO_2) and particulate matter (PM), the cost estimates were developed for representative units configured only with an existing CS-ESP. This particular configuration represents more than 60% of the existing fleet of coal-fired units and the most likely units to require significant add-on mercury control. Coals chosen for this analysis represent typical coals used at unscrubbed facilities. Cost estimates were developed by appropriately scaling the ACI equipment installation cost estimate developed by ADA-ES for the 608 MW Pleasant Prairie

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[4] Full-scale tests for bituminous coal were conducted in a manner that represented carbon injection into relatively clean flue-gas downstream of the power plant's primary particulate collection device and therefore neglected any mercury capture associated with the fly-ash. To estimate activated carbon requirements for aggregate mercury reductions at a more generic unit equipped with an existing CS-ESP, the two bituminous coal injection algorithms were "adjusted" to account for average mercury removal as indicated by the EPA ICR Phase III data (~36%). Because the ICR data indicates minimal capture (~3%) across a subbituminous fired unit equipped with a CS-ESP, no adjustments were made to the curves developed for subbituminous fired units. A more complete discussion is included in the appendix of this document.

unit. "Study level" cost estimates[5] were developed for equipment designed to achieve mercury control at low (50%), mid-range (60-70%), and high (90%) levels for both bituminous- and subbituminous-fired units. For configurations requiring a retrofit FF, EPA's CUECost program was used for the cost estimate of the FF equipment.

Full-scale testing has indicated that ACI upstream of a CS-ESP (ACI/ESP) should allow both bituminous and subbituminous units to achieve mid-range mercury reductions of between 60% and 70% at injection rates around 10-15 lbs/million acf (see Figure 1). Although regression analysis of full-scale ACI/ESP data shows that it may be possible to achieve higher mercury reductions at increased injection rates, the ACI/COHPAC configuration, with lower sorbent requirements, may prove more economical. Furthermore, while field testing at Brayton Point has demonstrated that 90% removal via ACI/ESP may be achievable, the data was obtained during relatively short-term testing. Long-term performance of high ACI rates into existing ESPs and the associated impact on the particulate control device has yet to be evaluated, and high mercury capture rates on the order of 90% may not be achievable over longer durations.

Comparison of Regression Data to DOE/NETL Pilot Scale Sorbent Injection Modeling

The mercury removal shown in Figures 1 and 2 is presented as a function of AC injection rate measured as pounds activated carbon/million actual cubic feet flue gas flow rate (lb/MMacf), and independent of flue gas mercury concentration. While the methodology presented in this report is based on the above approach, others have proposed carbon injection rates in terms of mass of carbon injected per mass of mercury in the flue gas (lb AC/lb mercury). The mass ratios resulting for the "representative" 500 MW power plant burning an average mercury content coal range from 5,700 lb carbon/lb mercury (50% bituminous CS-ESP) to approximately 43,000 lb carbon/lb mercury (60% subbituminous CS-ESP). For the 90% ACI/COHPAC case, carbon-to-mercury ratios were approximately 6,000 and 11,000 lb carbon/lb mercury for the bituminous and subbituminous cases, respectively. These numbers are in reasonable agreement with pilot scale data from DOE/NETL in-house research, where 90% removal was achieved across a FF at carbon-to-mercury ratios ranging from approximately 6,000 to 16,000 lb carbon/lb mercury.[6]

The carbon-to-mercury ratios that result when this methodology is applied to the widely varying mercury content of U.S. coals are also close to the range demonstrated by the DOE/NETL pilot-scale testing. At 90% ACI/COHPAC control, and at the low range of coal mercury content of 3 lb/Tbtu, the methodology used for this analysis represents carbon-to-mercury ratios of approximately 16,000 and 22,000 lb carbon/lb mercury for the bituminous and subbituminous cases, respectively. At 90% ACI/COHPAC control, and the upper range of coal mercury content of 14 lb/Tbtu, the methodology yields carbon-to-mercury ratios of approximately 3,500 and 4,600 lb carbon/lb mercury for the bituminous and subbituminous cases, respectively. These performance results, indicating a similar magnitude as the pilot-scale carbon injection data, fully

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[5] Cost estimates developed here are based on cost and performance data provided by ADA/ES, as well as the use of models developed for cost estimates of environmental control equipment specific to the utility industry (***Coal Utility Environmental Cost Version 1*** (Revised 2-9-2000 as CUECost3.xls)). The accuracy of the cost estimates presented here are expected to be nominally +/- 30%, similar to the accuracy of the rough-order-of-magnitude (ROM) costs or "study" level costs acceptable for regulatory development, as described in the ***EPA Air Pollution Control Cost Manual, Sixth Edition***, EPA-452-02-001 January 2002.

[6] Flora, J.R.V., et. al., ***Modeling Sorbent Injection for Mercury Control in Baghouse Filters: II-Pilot-Scale Studies and Model Evaluation***, Journal of the Air & Waste Management Association, Volume 43, April 2003.

support the use of algorithms based on flue gas flow rate to calculate "study level" costs for coals with mercury content similar to the ranges measured in EPA's mercury Information Collection Request (ICR).

Mercury Control Cost Estimates

Table 2 presents capital cost, total capital requirement (TCR), annual operating and maintenance (O&M) costs and cost of electricity (COE) increase for the various reduction scenarios for a representative 500 MW unit equipped with an existing CS-ESP, both with and without fly ash management and disposal cost impacts. The costs associated with the management and non-hazardous disposal of the captured AC are included as part of the annual O&M in all cases because these costs would be incurred regardless of existing fly ash management and disposal practices. Note that the COE estimates presented here are based on 20-year levelized costs and specific economic parameters that are identified in the appendix.

Sorbent injection into an existing ESP will result in commingling of the sorbent and ash and the ability to market the ash may be compromised. Because an important market for fly ash is the manufacture of concrete, any additional carbon content may render it unsuitable for sale. Carbon injection field-testing at Pleasant Prairie rendered the ash unsuitable for use in concrete during the entire test period. ACI at injection rates used for this analysis results in an increase in carbon-in-ash concentration ranging from approximately 0.4 wt% carbon to 8 wt% carbon. Along with the potential loss of revenue from the sale of the ash, the affected unit would need to pay for disposal of ash that would have otherwise been sold. Because all fly ash is collected upstream of the point of AC injection at units that install a polishing FF (ACI/COHPAC), there would be no added cost for fly ash disposal or loss of revenue from sale. However, as stated previously, a cost is assigned for the disposal of the injected activated carbon.

Incremental Cost of Mercury Reductions

The marginal or incremental cost of mercury reduction, i.e. the cost (in $/lb mercury removed) to achieve a specific reduction beyond a baseline, can vary significantly with various assumptions including the baseline mercury "co-benefit" capture performance of existing APCDs. Table 3 provides the incremental cost of control for each configuration included in Table 2.

The estimates developed here are based on a hypothetical representative 500 MW unit, with coal properties and existing co-benefit mercury capture based on averages derived from EPA's ICR data. Incremental costs for a unit defined by other assumptions, including size, heat rate, coal properties, and existing co-benefit mercury capture, will potentially result in costs very different than those presented here. It is theoretically possible for two different coal-fired electric generating units to have very similar annualized costs for mercury control yet have very different incremental control costs.

Table 2. Mercury Control Cost Estimate (2003$)

Fuel	Mercury Reduction	Unit Configuration	Capital Cost, $1,000[a]	Total Capital Requirement (TCR), $/kW	First Year Annual O&M, $1,000[b]	COE Increase, 20-year annualized costs and current dollar basis, mills/kWh	
						w/o by-product impact	with by-product impact
Bituminous	**50%**	ACI/ESP	$984	$1.97	$931	0.37	2.79
	70%	ACI/ESP	$984	$1.97	$3,401	1.27	3.69
	70%	ACI/ COHPAC	$28,267	$56.53	$2,609	1.89	1.89
	90%	ACI/ESP	$1,262	$2.52	$15,647	5.72	8.14
	90%	ACI/ COHPAC	$28,267	$56.53	$3,311	2.15	2.15
Subbituminous	**50%**	ACI/ESP	$984	$1.97	$1,501	0.58	1.82
	60%	ACI/ESP	$984	$1.97	$5,165	1.91	3.15
	60%	ACI/ COHPAC	$28,719	$57.44	$3,352	2.18	2.18
	90%	ACI/ COHPAC	$28,719	$57.44	$3,863	2.36	2.36

[a] Capital equipment cost for ACI dosing and storage equipment is assumed a "per installation" cost and is not expected to vary much with injection rate, with some increase assumed for significantly higher injection rates for higher levels of ACI/ESP control.

[b] Annual O&M includes sorbent consumption and disposal but does not include fly ash disposal costs or loss of revenue from by-product sales.

Table 3. Incremental Cost of Control, Current Dollar Basis (2003$)

Fuel	Mercury Reduction	Unit Configuration	Incremental Cost of Control, $/lb mercury removed	
			w/o by-product impact	with by-product impact
Bituminous	**50%**	ACI/ESP	$32,598	$245,731
	70%	ACI/ESP	$45,740	$133,796
	70%	ACI/COHPAC	$68,575	$68,602
	90%	ACI/ESP	$130,649	$185,962
	90%	ACI/COHPAC	$49,005	$49,022
Subbituminous	**50%**	ACI/ESP	$17,472	$54,950
	60%	ACI/ESP	$48,086	$79,318
	60%	ACI/COHPAC	$54,837	$54,837
	90%	ACI/COHPAC	$39,672	$39,672

The methodology used for estimating carbon injection sorbent requirements is based entirely on AC mass-per-volumetric-flue-gas-flow-rate (lb activated carbon/MMacf) for a desired level of mercury reduction. Therefore, for a given level of performance (e.g., 70%) at an individual unit, annualized capital and O&M costs would be independent of the mass of mercury captured. Figures 3 and 4 present the incremental cost of mercury removal as a function of coal mercury content for each reduction case included in Table 2 without considering by-product sales and disposal. Figures 5 and 6 present the same curves for each reduction case included in Table 2 and include the impact of lost sales and required disposal of all fly ash. Also included in Figures 3 through 6 are cumulative frequency curves of the coal mercury content for West Virginia bituminous and Wyoming subbituminous coals from the ICR Phase II data. The data points within the ovals represent the approximate average coal mercury content of the coals used for this exercise.

Figure 3. Incremental Cost of Mercury Control, Excluding Lost Revenue and Added By-Product Disposal Cost for Bituminous Fired Unit

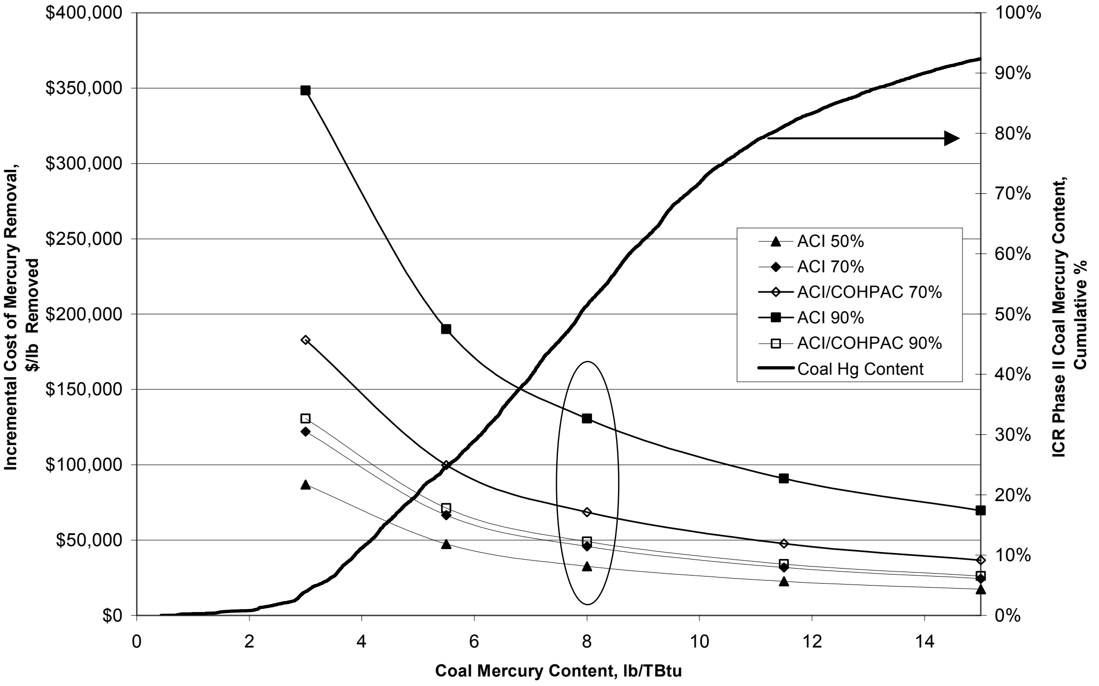


Figure 4. Incremental Cost of Mercury Control, Excluding Lost Revenue and Added By-Product Disposal Cost for Subbituminous Fired Unit

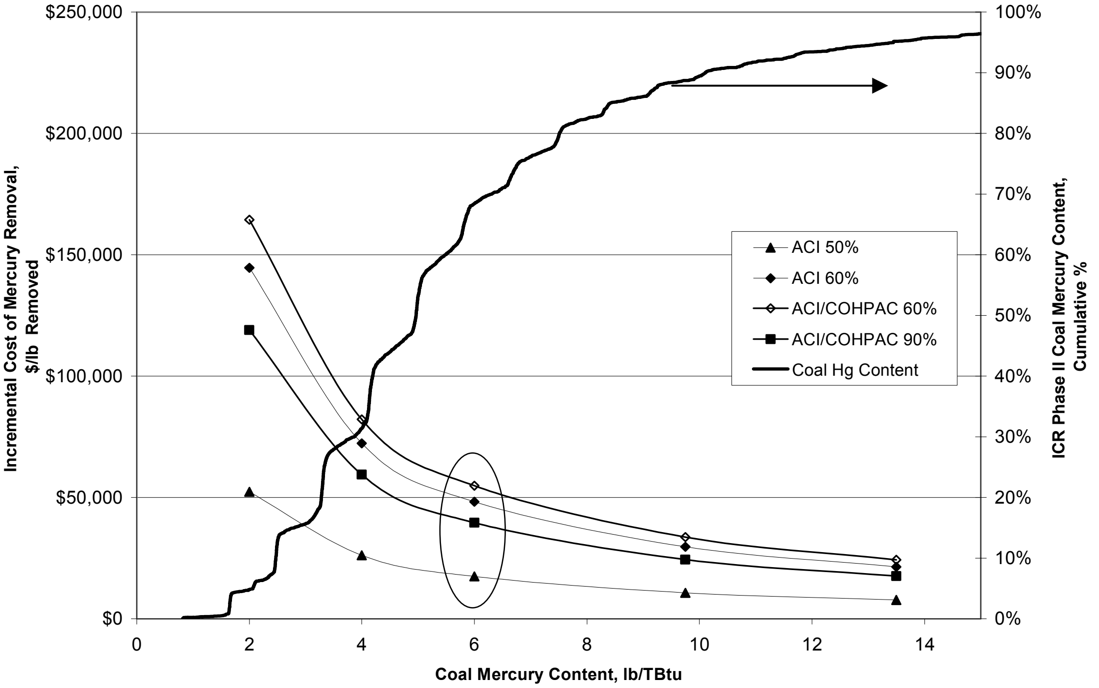


Figure 5. Incremental Cost of Mercury Control Including Lost Revenue and Added By-Product Disposal Cost, Bituminous Fired Unit

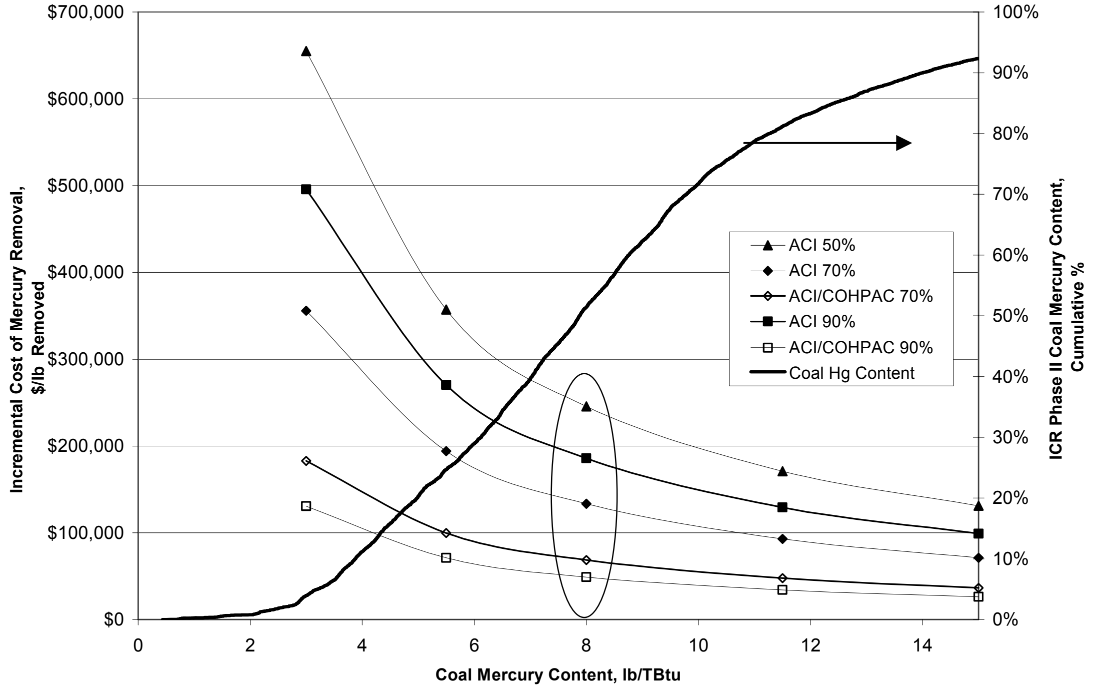
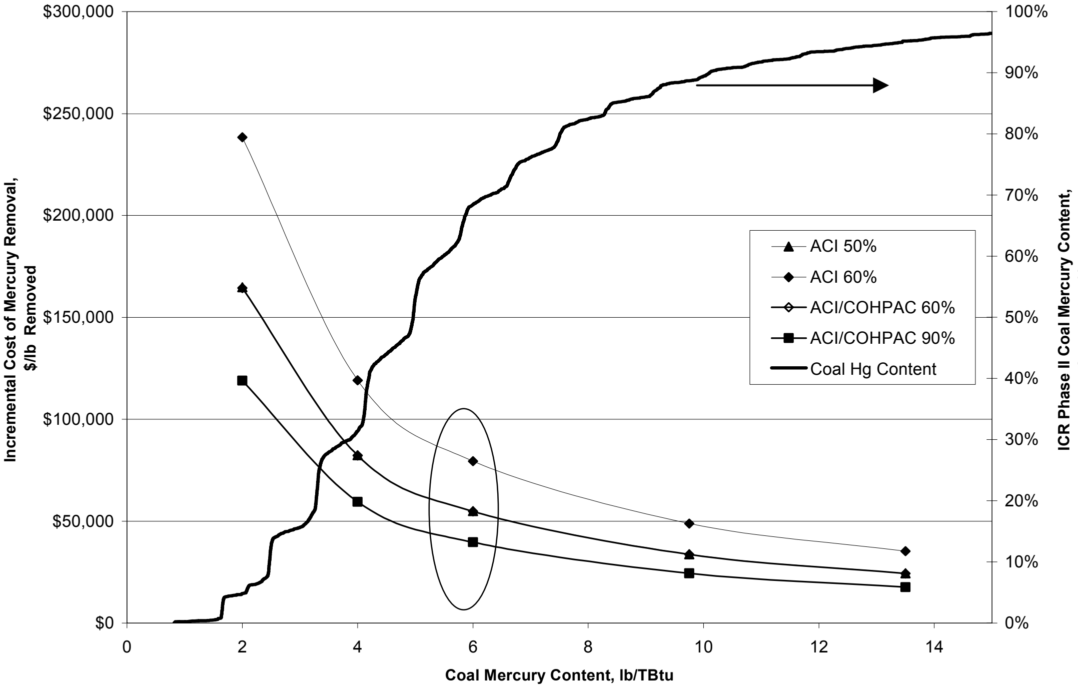


Figure 6. Incremental Cost of Mercury Control Including Lost Revenue and Added By-Product Disposal Cost, Subbituminous Fired Unit



Note: In this analysis, the incremental cost for ACI 50% and ACI/COHPAC 60% are approximately equal and appear as a single curve on Figure 6.

The examples shown above demonstrate how, for a given level of control (and therefore given levelized cost), a single parameter such as coal mercury content can result in a broad range of incremental cost of mercury removal. Therefore, the incremental cost of mercury control is inextricably linked to the specific assumptions used in the development of the particular cost estimate, and any comparison of that estimate to other scenarios should be conducted cautiously, with a clear understanding of the context of the specific application. The usefulness of the incremental cost of mercury reduction is most suited for determining the economic impact to a well-defined existing unit considering several control options or for estimates of *"average"* unit impacts in national-scale energy models such as the National Energy Modeling System (NEMS) or the Integrated Planning Model (IPM).

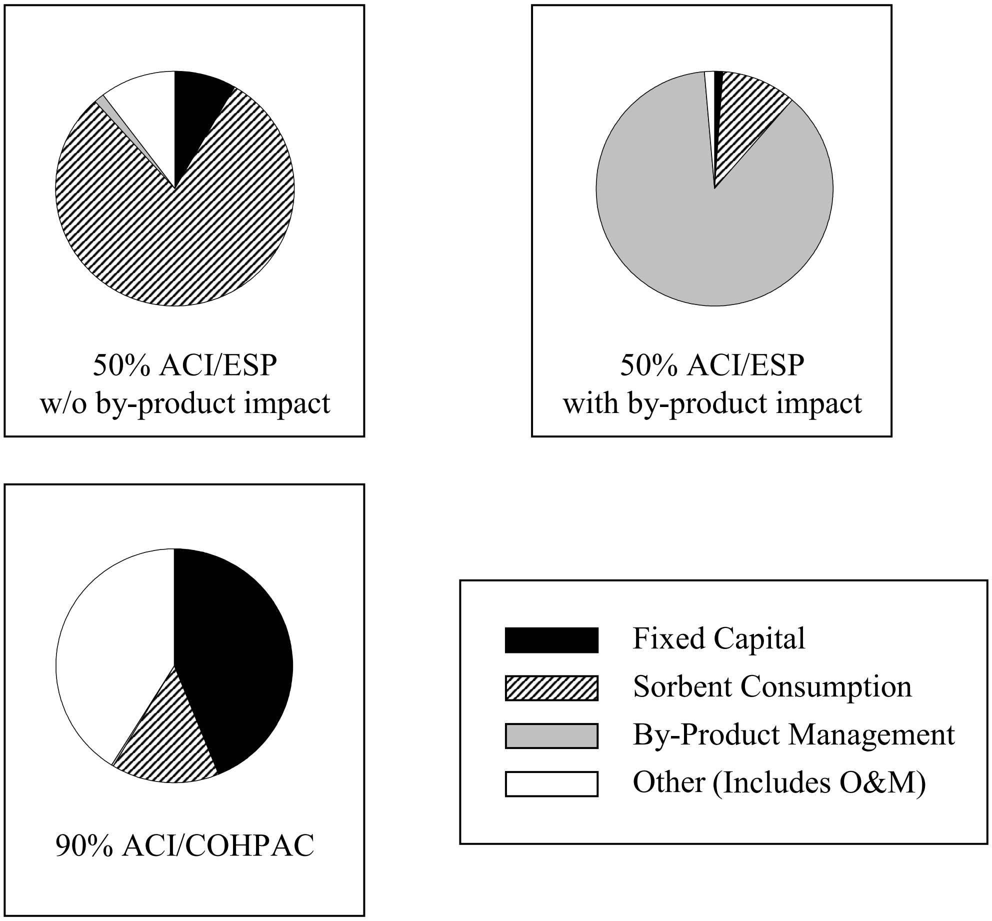
IV. DISCUSSION

The economics of mercury control via ACI can be strongly influenced by a number of key components. The three most significant cost components are:

- Sorbent consumption
- By-product management and disposal
- Capital and operating costs associated with a new pulse-jet FF for carbon capture downstream of an ESP (ACI/COHPAC)

Figure 7 provides a graphical example of the relative significance of the major cost components for three of the bituminous-fired cost estimates. It is clear from the examples that for each configuration, a different cost component has a dominant role in the overall costs. For the carbon injection only configuration (ACI/ESP, excluding impact to by-product management), the largest cost component is sorbent consumption. When impacts to by-product management costs are included, those costs become the most significant component. For the carbon injection and COHPAC™ retrofit configuration (ACI/COHPAC), the fixed capital and O&M costs become the most significant component.

Figure 7. Relative Significance of Major Cost Components to 20-Year Levelized Costs, Bituminous-Fired Unit with an Existing CS-ESP



A brief discussion of each specific cost component follows:

Sorbent Consumption

Sorbent consumption for ACI technology is directly related to the desired level of mercury control. As shown in Figure 2, ACI injection into an existing CS-ESP indicates 50-60% overall mercury reduction is achievable for subbituminous and bituminous coals at injection rates of approximately 5 lb/MMacf. At injection rates greater than 5 lb/MMacf, the performance curves begin to reach a maximum and increasingly more activated carbon is needed to achieve incremental improvements in mercury reduction. Test data from Pleasant Prairie indicates that even at very high ACI rates, an overall reduction slightly greater than 60% is the maximum that can be achieved through AC injection into a CS-ESP for a subbituminous-fired unit.

For the ACI/ESP configuration, sorbent operating costs (excluding fly ash management and disposal costs) are the most significant component of the increase to COE.[7] Delivered sorbent costs for this analysis are assumed to be \$0.50/lb of activated carbon. Clearly, the assumption of any cost other than that assumed in this study can have a strong positive or negative effect on the economics of mercury control.

As can be seen in Figure 7, the cost associated with sorbent consumption is a sizeable component of all examples and efforts to reduce either sorbent cost or sorbent injection rate could provide for significant cost savings. Efforts are currently directed toward the development of lower-cost and higher performing sorbents (i.e., sorbents that provide equal or greater mercury capture at lower injection rates). However, it should be clear that any "improved" sorbent, such as sulfur- or iodine-impregnated sorbents must have significant performance improvements with minimal added cost. Some currently investigated impregnated sorbents have been estimated to cost upwards of \$7/lb. At \$7/lb, sorbent performance would need to be notably superior, or at the very least provide a viable, low-cost sorbent regeneration option, for the improved sorbent to be a cost-effective alternative to currently available activated carbon. Additionally, as discussed below, the affect that a sorbent may have on the ability to market the fly ash should be considered in the context of sorbent research and development activities. In all cases, any sorbent improvement research should include a thorough economic analysis, including evaluation of balance-of-plant impacts as well as possible effects on fly ash sales or management methods should the sorbent be injected into an existing particulate control device and commingled with the fly ash.

By-product Management and Disposal

Coal-fired boilers create large amounts of solid by-products, a result of the ash associated with coal. Particulate control devices such as ESPs are installed with the sole purpose of capturing the fly ash entrained in the flue gas. The captured fly ash is either disposed of in landfills or utilized in a variety of applications. Table 4 includes recent American Coal Ash Association (ACAA) statistics on national utility fly ash generation and reuse.

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[7] The contribution of ACI capital equipment cost to the increase of COE is low (~10% for 50% ACI/CS-ESP, much less for ACI/COHPAC), even compared to annual sorbent consumption at low AC injection rates. It should be noted that even though low AC injection rates would indicate ACI equipment design requirements for less than 500 lbs/hour operating injection rate, ADA/ES has determined that there is little economy-of-scale for designing less than 500 lbs/hour. Recent experience by ADA/ES suggests that capital equipment costs for activated carbon injection dosing equipment would not vary much for a wide range of dosing rates and ADA/ES suggests the use of a set cost per installation with slight scaling for very high injection rates ($\geq$2000 lbs/hr).

Table 4. 2001 Fly Ash Generation and Utilization Statistics[8]

Overall Utility Coal Combustion By-product Statistics			
Total Fly Ash Generation	68,123,551 tons/year		
Total Fly Ash Utilization	22,004,955 tons/year		
% of Total Fly Ash Generation that is Utilized	32.30%		
Individual Fly Ash Utilization			
	Tons/year	**% of Total Generation**	**% of Total Use**
Cement/Concrete/Grout	12,360,242	18%	56%
Raw Feed for Cement Clinker	1,033,384	2%	5%
Flowable Fill	803,703	1%	4%
Structural Fills	3,209,508	5%	15%
Road Base/Subbase	1,026,821	2%	5%
Soil Modification	736,986	1%	3%
Mineral Filler	106,539	<1%	<1%
Mining Applications	819,588	1%	4%
Waste Stabilization/Solidification	1,439,407	2%	7%
Agriculture	20,506	<1%	<1%
Miscellaneous/Other	448,271	1%	2%

It is clear from Table 4 that the greatest utilization of fly ash is in the cement/concrete/grout category, accounting for approximately 18% of all fly ash generated and more than half of all fly ash utilized. The sale of fly ash by a coal-fired generator is dependant primarily on suitability for use and available market. Currently, a substantial portion of fly ash is disposed of and not utilized. However, some generators sell nearly all of their ash. One of the highest-value reuse applications for fly ash is use as a substitute for Portland cement, and many plants sell their fly ash for that purpose rather than for use in low-value applications, such as road-base or agricultural applications or disposing of the ash in surface impoundments or landfills. The utilization of fly ash in concrete production is particularly sensitive to carbon content, and any additional carbon may render fly ash unsuitable for use. Even at low levels of carbon contamination, the association of fly ash with mercury capture may result in loss of market simply due to a perceived association with the hazards of mercury.

The increase in COE associated with ACI presented in Table 2 demonstrates the impact of added by-product management and disposal costs. The added costs for fly ash management assumes the loss of current avoided disposal costs as well as lost revenue from the sale of all fly ash captured in the ESP. As seen in Table 2, the loss of revenue and added disposal cost can be substantial. The increase in COE presented in Table 2 represents estimates for revenue from fly ash sale and non-hazardous disposal costs of $18/ton and $17/ton respectively. Table 2 indicates that the impact to COE due to the economics associated with loss of fly ash sales and disposal can be significant, more than 80% of the total cost for the 50% mercury reduction case at a bituminous-fired unit.

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[8] American Coal Ash Association, 2001 coal combustion product (CCP) production and use statistics, URL http://www.acaa-usa.org/PDF/ACAA2001CCPSurvey.pdf

The by-product disposal cost assumption used for this analysis, \$17/ton, was estimated based on an average of a cost range provided by ACAA. It is recognized that disposal costs can vary significantly based on a number of factors, including region, disposal method, and bulk transportation method (e.g., piped or trucked, etc.). ACAA estimates that costs could range from \$3/ton to greater than \$30/ton. One eastern coal-fired utility estimated fly ash disposal costs ranging between \$2 and \$10/ton. However, this particular utility indicates that they consider their ash disposal costs to be lower than average. Furthermore, should fly ash mixed with activated carbon be considered a hazardous waste, management and disposal costs would be significantly higher, likely in excess of \$100/ton and perhaps greater than \$1000/ton.

The valuation used for fly ash sales in this analysis is \$18/ton based on estimates provided by ACAA, weighted by fly ash utilization distribution. As with disposal costs, the revenue from by-product sales can vary significantly by regional demand and end-use. Input from discussions with ACAA staff has provided a wide range of values for fly ash use, with low-value use approximately \$3/ton. High-value use in cement typically varies based on demand and can range from \$20/ton in eastern regions to more than \$35/ton in western regions. The same eastern coal-fired utility estimated ash value for use in concrete of approximately \$5/ton.

While the ACI/COHPAC configuration does not impact the ability to market fly ash, waste disposal issues may also exist. It is possible that activated carbon captured in the COHPAC™ may not fall under the existing Bevill Exemption because it may not fit the description of a listed waste. If so, it would be likely that all captured AC would be managed and disposed of under regulations required by the Resource Conservation and Recovery Act (RCRA). Because any mercury capture by AC would result in elevated mercury concentrations of the sorbent, possible trace levels of mercury may trigger required compliance with RCRA Subtitle C hazardous waste regulations. RCRA Subtitle C regulations are substantially more stringent than Subtitle D non-hazardous waste regulations and would result in more expensive waste management requirements. For this analysis, the captured AC is assumed a non-hazardous waste and management and disposal costs are equivalent to that of fly ash.

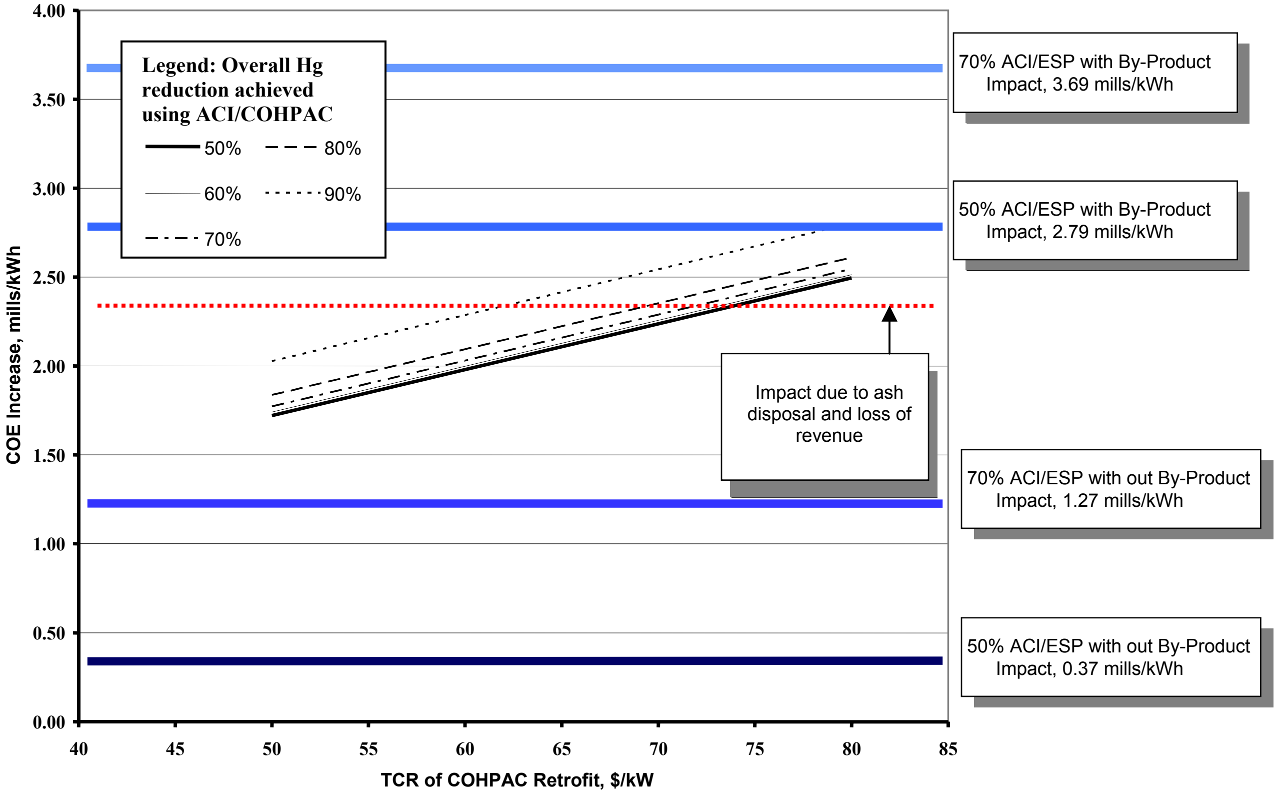
COHPAC Capital Cost Including Economic Life

AC injected downstream of an existing ESP and upstream of a FF has demonstrated the ability to achieve high levels of mercury control at relatively low AC injection rates for bituminous-fired units. Although DOE/NETL has not funded any full-scale testing of the ACI/COHPAC configuration for low-rank coals, preliminary data from EPRI pilot-testing suggests that the same may be true for subbituminous-fired units.

The primary drawback to the ACI/COHPAC configuration is the capital cost associated with installation of the new FF. Because a primary design characteristic of FFs is the gas-to-cloth ratio, sizing for installation would be mostly dependent on flue gas flow rate and less so on desired mercury capture performance. Therefore, for a given unit and ACI rates of less than 5 lbs/MMacf, it is not expected that the capital investment for the ACI/COHPAC configuration would vary at all with regard to desired level of mercury control. It should be noted that the COHPAC™ costs were modeled using a gas-to-cloth ratio of approximately 5 ACFM/ft^2. Designing a COHPAC™ to a higher ratio, perhaps in the 8-12 ACFM/ft^2 range, may allow for a measurable reduction in capital equipment costs, albeit at the cost of higher energy consumption. Additionally, a COHPAC™ with a high air-to-cloth ratio may require an increased cleaning frequency and perhaps result in decreased bag life. Total capital requirement (TCR) for the COHPAC™ retrofit installation were obtained using EPA's CUECost model for a pulse-jet FF and is assumed approximately $55/kW. It is worthwhile noting that CUECost is relatively insensitive to scaling based on air-to-cloth ratios and it was not possible to develop a cost estimate for a COHPAC™ unit with a high air-to-cloth ratio. Additionally, recent attempts to obtain updated cost projections have led to estimates significantly greater than those projected using CUECost.

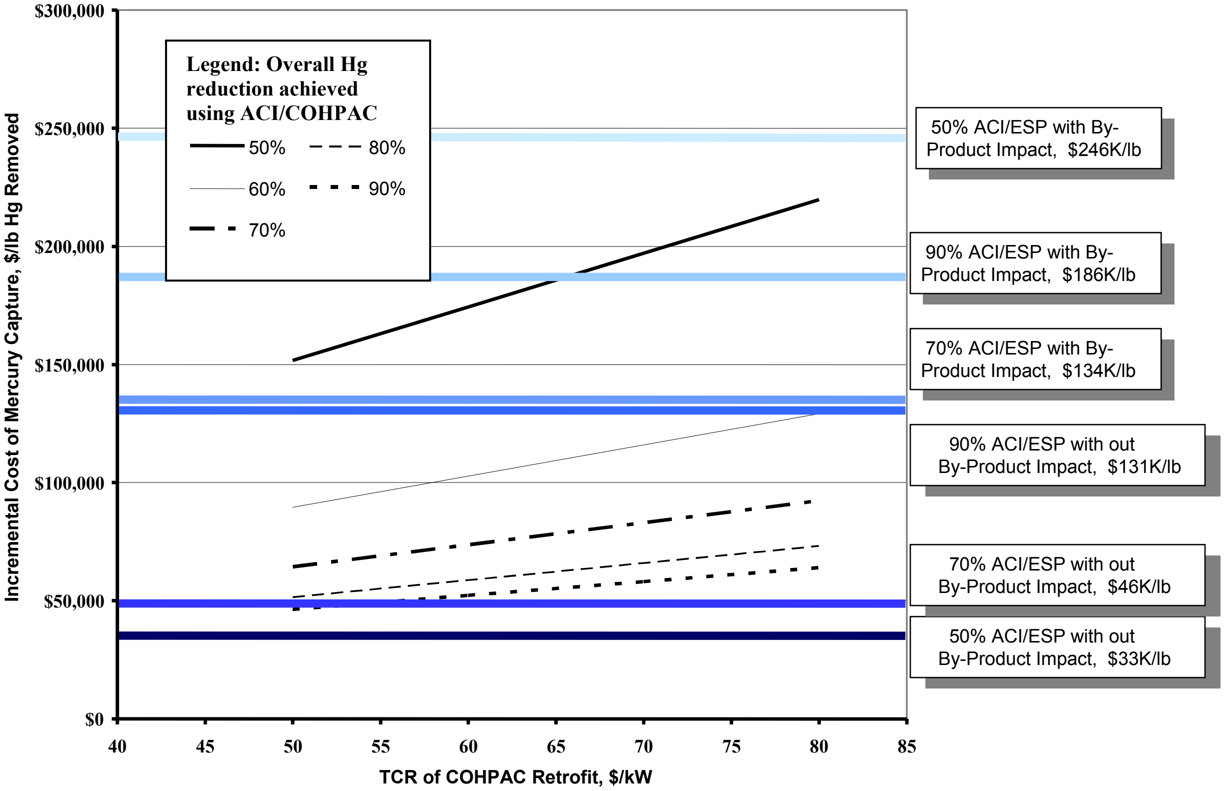
A sensitivity analysis was conducted to approximate the overall effect that a different TCR would have on the economics and cost effectiveness of mercury control using ACI and the COHPAC configuration. Using the same economic assumptions and dollar basis as in Tables 2 and 3, Figures 8 and 9 compare the use of a COHPAC™ retrofit TCR ranging from $50/kW to$80/kW for the retrofit of a bituminous-fired unit. Figure 8 compares COHPAC™ TCR to COE increase and Figure 9 compares COHPAC™ TCR to incremental cost of mercury control. Also included in Figures 8 and 9 are comparison bars for the ACI/ESP configuration at various levels of mercury control.

Figure 8. Effect on the 20-Year Levelized COE Increase due to Mercury Control by Varying TCR for COHPAC™ Retrofit on a Bituminous-Fired Unit



Because the increase to COE for the 90% ACI/ESP configuration is approximately twice that of the highest COE increase of the ACI/COHPAC configurations evaluated (90% removal, $80/kW), values were not included in Figure 8. Additionally, under the assumptions used for this analysis, the low endpoint of the ACI/COHPAC configuration, (50% removal, $50/kW) is equivalent in cost to approximately 75% removal by ACI into an existing CS-ESP. Conversely, the high endpoint of the ACI/COHPAC configuration (90% removal, $80/kW) is equivalent in cost to approximately 82% removal by ACI into an existing CS-ESP.

Figure 9. Effect on the Incremental Cost of Mercury Control by Varying TCR for COHPAC™ Retrofit on a Bituminous-Fired Unit



While in most cases the ACI/COHPAC configuration appears to be favorable for higher levels of mercury control (>60% for subbituminous coals, > 70% for bituminous coals), cost-effectiveness of installation for lower levels of control would depend more on site-specific factors, such as utilization and disposition of fly ash as well as near-term and longer-term plans for the generating unit. For units that currently dispose of their fly ash, AC injection into an existing ESP may be the most cost-effective method to achieve mid-level mercury reductions. If fly ash sales (and avoided disposal costs) are an important source of revenue, then ACI/COHPAC for moderate control levels may be cost-effective.

Perhaps just as important as sorbent and ash management to the cost-effectiveness of the ACI/COHPAC configuration is the near-term and longer-term plans for an individual generating unit. The cost estimates presented here are for a nominal 500 MW low-sulfur bituminous- or subbituminous-fired unit equipped only with an existing CS-ESP for particulate control. While mercury emissions from coal-fired units is the pollutant currently receiving the most attention, other pollutants such as NOx and SO_2 are also likely to be regulated more stringently. Either through the NOx SIP Call, development of revised National Ambient Air Quality Standards (NAAQS) for PM2.5 and ozone, regional haze regulations, or any one of the several proposed multi-pollutant legislative acts, coal-fired units may also be required to install additional controls for NOx and SO_2 emissions. The co-benefit mercury capture resulting from the installation of additional controls (e.g., selective catalytic reduction (SCR) for NOx control and wet FGD for SO_2 control) at a unit equipped with an existing CS-ESP may greatly reduce or even eliminate the need for ACI. Because cost-effectiveness of the ACI/COHPAC configuration as a method for mercury control is strongly dependent on the economic life of the installed equipment, the timing of required mercury reductions and regulations for other pollutants may significantly impact the overall cost-effectiveness of a specific compliance strategy. The annual costs developed here are based on a 20-year service life, and an increase in COE can result from significantly shorter time periods.

Other Issues Affecting the Economics of Mercury Control

Additional factors can influence the cost of control, including, but not limited to, economic factors (labor rate, tax and contingencies, etc.), process disruptions (unexpected or excessive outages, etc.), and modifications to existing equipment. The estimates developed here assume an uncomplicated COHPAC™ retrofit and minimal economic impact due to FF and ACI equipment tie-in, assuming that tie-in occurs during a regular scheduled plant outage. The estimates are also based on the assumption that the existing ESP and/or FF retrofit performance will not be negatively affected by the additional particulate loading. This assumption has yet to be demonstrated on a long term basis, and recent experience at Gaston has demonstrated increased FF bag cleaning frequency as a function of carbon injection rate. Compared to the longer-term testing at Gaston, COHPAC™ cleaning frequency would be approximately 2.5-3 pulses/bag/hour for the ACI/COHPAC injection rate to achieve 90% capture used in this analysis. However, it should also be noted that baseline co-benefit mercury capture at Gaston was greater during the longer-term testing than the initial field demonstration tests, therefore requiring lower ACI rate to achieve high mercury capture. In addition, COHPAC™ inlet dust loading at Gaston was greater during the longer-term testing than the shorter-term testing therefore necessitating increased cleaning frequency at carbon injection rates similar to those evaluated during initial field testing.[9] The variability in ACI performance and balance-of-plant impact (i.e., increased COHPAC™ cleaning frequency) observed at Gaston demonstrate the need for additional long-term testing to fully characterize mercury control using ACI. Altering conditions or requirements beyond the above stated assumptions would likely result in significantly different costs than those included here.

V. SUMMARY

For the scenarios considered in this study, the analysis indicates that the three most important factors affecting the economics of ACI for mercury control are: 1) sorbent consumption, 2) impact to by-product management and disposal and 3) costs associated with the fabric filter

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[9] Bustard, C. Jean, et.al., ***Long-Term Evaluation of Activated Carbon Injection for Mercury Control Upstream of a COHPAC Fabric Filter***, Presented at the Fourth International Conference on Air Quality, Washington DC, September 2003.

retrofit for the ACI/COHPAC configuration. Capital costs range from approximately $2/kW to $57/kW, the lower cost representing capital requirements of the activated carbon storage and injection equipment and the higher cost representing the capital requirements of the COHPAC^{TM} retrofit. The impact to the COE ranges from approximately 0.37 mills/kWh to 8.14 mills/kWh, depending on the particular control configuration and the inclusion of loss of revenue and added disposal costs due to AC impact on fly ash valuation. The configuration that results in a COE impact of 8.14 mills/kWh represents an unlikely case of 90% control by activated carbon injection into an existing CS-ESP at approximately 42 lbs/MMacf, and loss of revenue and added disposal costs for all fly ash. It is unlikely that 90% control would be attempted simply by injecting carbon at such a high rate into an existing ESP. It is also questionable that the existing ESP could handle such a high carbon load without degradation of particulate collection efficiency. A more likely estimate of the impact on COE for 90% reduction is the application of ACI with a COHPAC^{TM} retrofit, yielding an increase in COE of approximately 2.15 to 2.36 mills/kWh for bituminous- and subbituminous-fired units respectively. The significantly lower impact to COE in the ACI/COHPAC configuration, relative to ACI into an existing CS-ESP, is a result of decreased sorbent consumption and no impact to fly ash revenue.

The costs resulting from this analysis are on the order of a "study" estimate, and are expected to have a nominal accuracy of ±30%. Cost estimates were developed based on sorbent requirements derived from a limited data set of relatively short-term full-scale field testing and a combination of existing cost models and equipment costs developed from permanent installation estimates associated with the full-scale field tests of activated carbon injection. The ACI cost estimates and impact to COE are based on a number of specific assumptions and the use of other assumptions may result in estimates significantly different than those presented here. Factors that can affect the costs include, but are not limited to:

- Sorbent consumption and price;
- Economic assumptions including economic life of capital equipment;
- Difficulty of retrofit including extended outages during equipment tie-in;
- Equipment specifications including FF air-to-cloth ratio and bag life; and
- Value of fly ash sales and disposal cost (including assumption that by-products are exempt from all hazardous waste management and disposal requirements).

In terms of the incremental cost of controlling mercury emissions, a broad range results, from approximately $18,000/lb mercury removed (50% reduction for subbituminous ACI/ESP without impact to ash management) to $246,000/lb mercury removed (50% reduction for bituminous ACI/ESP and loss of revenue and added disposal cost for all fly ash). This range is due to a number of factors, including coal rank, desired level of control, and the impact that ACI has on ash sales and disposal requirements. When ash sales and disposal are not included, the incremental cost ranges from approximately $18,000/lb (50% reduction for subbituminous ACI/ESP) to approximately $69,000/lb (70% reduction for bituminous ACI/COHPAC). That range does not include the 90% bituminous ACI/ESP configuration, which due to an increased rate of sorbent consumption has an incremental cost of control of approximately $131,000/lb mercury removed. When fly ash sales are negatively impacted and combined lost revenue and added disposal costs are included, the incremental cost of mercury control is estimated to range from approximately $40,000/lb (90% reduction for subbituminous ACI/COHPAC) to $246,000/lb (50% reduction for bituminous ACI/ESP). For most cases, in terms of incremental cost of control, costs are lower for subbituminous units than for a similar control level and configuration installed at a bituminous-fired unit. The reason that the incremental cost is lower for subbituminous-fired units is because it is assumed there is no co-benefit mercury capture of the existing air pollution control equipment for that case. With the assumption of no co-benefit mercury capture for subbituminous-fired unit, compared to the assumed 36% co-benefit mercury capture of the existing CS-ESP for the bituminous-fired unit, incremental mercury removal resulting from ACI is higher and therefore the incremental cost of removal is lower. However, most other costs (e.g., capital, O&M), exclusive of ash sales and disposal, are higher for the subbituminous-fired units. Costs other than incremental cost of control are higher for subbituminous-fired units because, for a given overall mercury reduction, the carbon injection requirements are greater than that of a comparable bituminous-fired unit (see Figure 2).

In addition to the impact on the incremental cost of mercury reduction due to the co-benefit mercury capture of existing equipment, coal mercury content can significantly affect the incremental cost of control. The methodology developed for this report estimates ACI requirements in terms of flue gas flow rate and is independent of flue gas mercury concentration. Thus, ACI rates would be the same for similar coals regardless of mercury content. ICR data for the 90th percentile of the mercury content of the coals used for this analysis ranges from approximately 3 lb/Tbtu to 17 lb/Tbtu for WV bituminous coals, and ranges from 2 lb/Tbtu to 13 lb/Tbtu for WY subbituminous coals. Therefore, incremental mercury control costs can vary by more than a factor of six solely due to coal mercury content.

Opportunities exist to lower the cost of mercury control using sorbent injection technology. Research directed at the development of lower cost, higher efficiency sorbents that have minimal effect on by-product utilization is one area that may provide for significant operating cost reductions. Additionally, sorbent and ash beneficiation technologies may provide for reduced annual costs by decreasing sorbent consumption. Furthermore, research directed at improving baghouse operations that can prolong bag life, reduce cleaning frequency, provide for operation at higher air-to-cloth ratios, or perhaps reduce sorbent requirements (e.g., sorbent impregnated bag materials) may also provide cost reduction opportunities. Capital requirements for sorbent injection equipment however appear to be small compared to the other components such as sorbent consumption, by-product management, and capital requirements of a retrofit COHPAC™ system and additional reductions in the capital cost of injection technology would not likely provide significant economic improvements. In all cases, the economics must be strongly weighted toward significant process improvements at minimal additional costs.

While mercury control at coal-fired utility boilers using activated carbon injection appears to be technologically feasible, many uncertainties continue to exist. Among those include the demonstration of consistent, long-term performance of ACI for mercury control as well as impact to overall plant operations. Additionally, necessary demonstration of ACI mercury control for a variety of coals both within a coal rank and across coal ranks is necessary to accurately assess the ability to implement ACI technology throughout the existing fleet of coal-fired utility boilers. Furthermore, additional understanding of the mechanisms that control mercury capture using ACI, as well as refined methods of flue-gas mercury measurements will provide additional knowledge for efficient application of ACI technology as well as provide opportunities to lower the cost of mercury control by potentially facilitating the development of lower cost sorbent technologies.

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APPENDIX

Key Assumptions, Regression Details, and Summary Slides of Control Cost Estimate

Key Assumptions Used in Cost of Control Estimates

Power Plant Assumptions

Coal Type	Wyoming PRB	WV Low-Sulfur Bituminous
Power Plant Size, MWe Net	500	500
Net Plant Heat Rate, Btu/kWh	10,633	9,745
Capacity Factor	80%	80%
Air Heater Outlet Temperature, ^{o}F	280	280
Air Heater Outlet Flue Gas Flow Rate, ACFM	1,974,671	1,710,656
% Ash exiting the boiler	80	80
Coal Mercury Content, lb/Trillion Btu	6	8
Air-to-Cloth Ratio for COHPAC, ACFM/ft^2	5.08	5.08

Coal Properties

Coal Ultimate Analysis (ASTM, as rec'd), wt%		
Moisture	30.24	5.00
Carbon	48.18	65.99
Hydrogen	3.31	4.75
Nitrogen	0.70	0.70
Chlorine	0.01	0.10
Sulfur	0.37	0.89
Ash	5.32	16.60
Oxygen	11.87	5.97
TOTAL	100.00	100.00
Modified Mott Spooner HHV (Btu/lb) - ***calc***	8,227	12,058
HHV (Btu/lb) - used	8,429	12,392

Coal Ash Analysis (ASTM, as rec'd), wt%		
SiO2	35.51	50.68
Al2O3	17.11	29.00
TiO2	1.26	1.70
Fe2O3	6.07	9.00
CaO	26.67	5.50
MgO	5.30	1.00
Na2O	1.68	0.40
K2O	2.87	0.90
P2O5	0.97	0.60
SO3	1.56	1.22
Other Unaccounted for	1.00	0.00
TOTAL	100.00	100.00

Capital Costs

Indirects		
General Facilities	10%	10%
Engineering Fees	10%	10%
Project Contingency	15%	15%
Process Contingency	5%	5%

Variable O&M and Costs

Sorbent Costs	$0.50/lb	$0.50/lb
Activated Carbon Disposal Costs	$17/ton	$17/ton
Fly ash Disposal Costs	$17/ton	$17/ton
Revenue From Fly Ash Sales	$18/ton	$18/ton
Power Cost	$0.05/kW	$0.05/kW
Operating Labor	$45/hr	$45/hr
PAC Injection Maintenance Costs	5% of equipment cost	5% of equipment cost
FF Maintenance Costs	5% of equipment cost	5% of equipment cost
PAC Injection Periodic Replacement Items	Flat	Flat
FF Bag replacement	5-year life	5-year life

Economic Factors

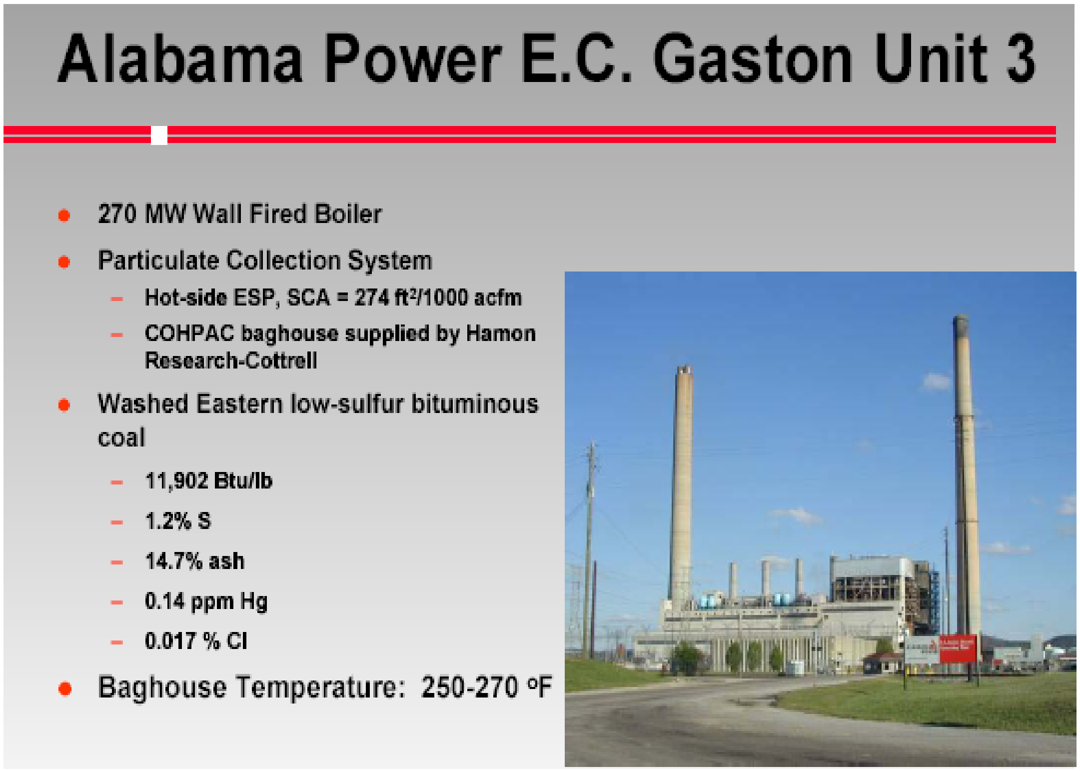
Cost Basis - Year Dollars	Current 2003	Current 2003
Capital Esc During Construction	1.5%	1.5%
Construction Years	0.5	0.5
Annual Inflation	2.5%	2.5%
Discount Rate (MAR)	9.2%	9.2%
AFUDC Rate	10.8%	10.8%
First Year Fixed Charge Rate, Current$	22.3%	22.3%
First Year Fixed Charge Rate, Const$	15.7%	15.7%
Lev Fixed Charge Rate, Current$ (FCR)	16.9%	16.9%
Lev Fixed Charge Rate, Const$ (FCR)	11.7%	11.7%
Service Life (years)	20	20
Escalation Rates :		
Consumables (O & M)	3.0%	3.0%
Fuel	5.0%	5.0%
Power	3.0%	3.0%

Activated Carbon Injection Field Test Results

Full-scale field testing of mercury emission control technology has been reported for three configurations: (1) ACI downstream of a hot-side ESP and upstream of a high velocity pulse jet fabric filter – ACI/COHPAC; (2) ACI downstream of an air preheater and upstream of a cold-side ESP using subbituminous coal – ACI/SUB-ESP; and (3) ACI downstream of an air preheater and upstream of a cold-side ESP using bituminous coal – ACI/BIT-ESP. The mercury control performance obtained for each configuration is discussed first.

ACI/COHPAC Performance

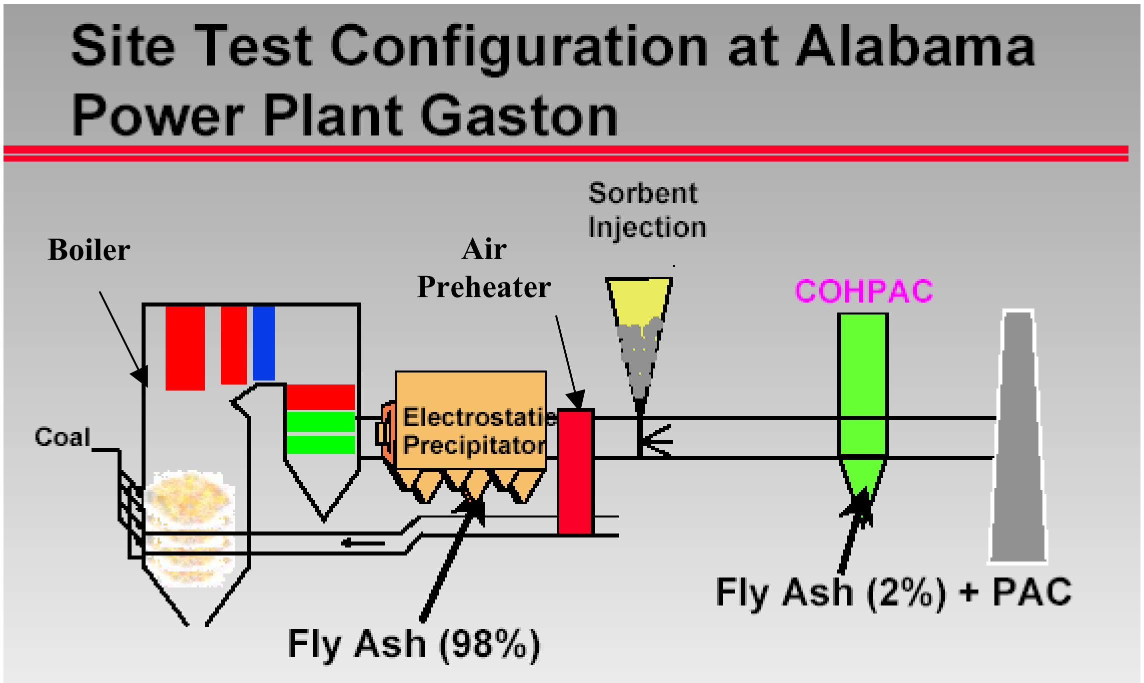
Mercury control performance with ACI/COHPAC technology was performed at the Gaston coal power plant. Some particulars of the test site are provided in the following graphic.



Alabama Power E.C. Gaston Unit 3

- 270 MW Wall Fired Boiler
- Particulate Collection System
  - Hot-side ESP, SCA = 274 ft^2/1000 acfm
  - COHPAC baghouse supplied by Hamon Research-Cottrell
- Washed Eastern low-sulfur bituminous coal
  - 11,902 Btu/lb
  - 1.2% S
  - 14.7% ash
  - 0.14 ppm Hg
  - 0.017 % Cl
- Baghouse Temperature: 250-270 °F

The tests were conducted in three phases (baseline, parametric and long term testing). Parametric tests were conducted during March 2001. The general configuration of the control equipment is shown in the following figure.



Site Test Configuration at Alabama Power Plant Gaston

Here, PAC refers to powdered activated carbon. Most of the fly ash is captured in the hot-side electrostatic precipitator (ESP) with little associated capture of mercury. If one assumes that mercury capture is not dependent on the uncontrolled mercury emission concentration, the ACI/COHPAC technology could be thought to represent a sequential mercury capture mechanism that is independent of the performance of each device. This is an important point to address in transferring results of performance from the Gaston site to other sites that could be adapted to this technology.

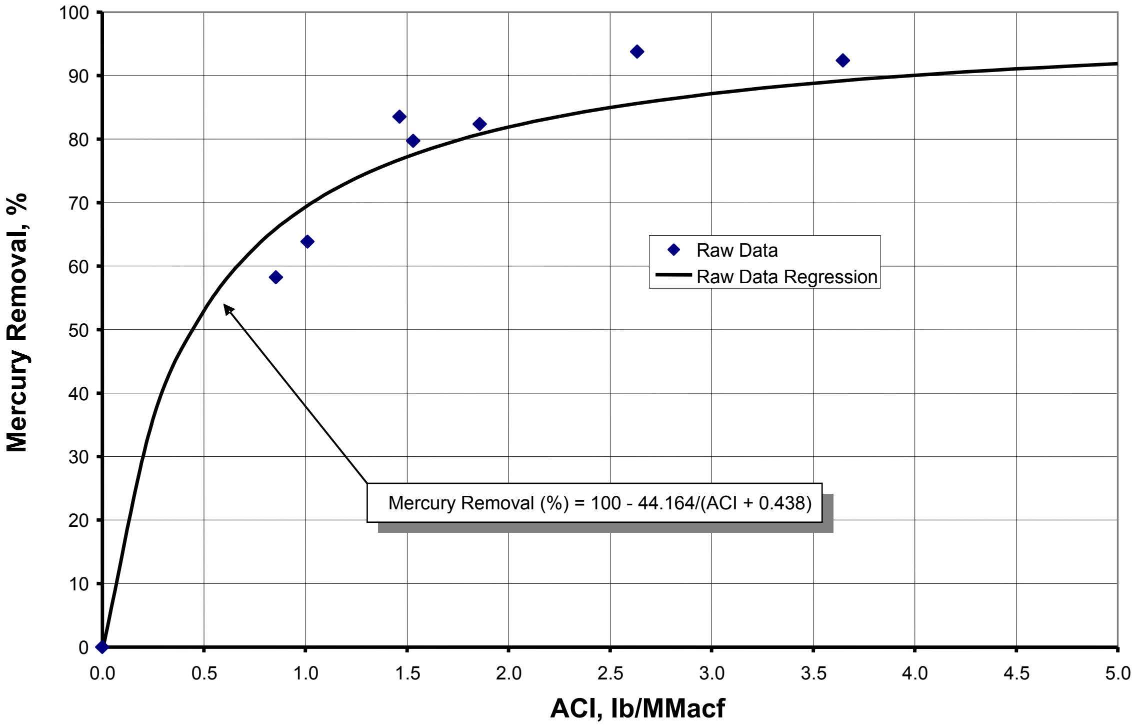
The results of the full-scale tests are shown in the following figure. The diamond symbols represent the measurements at the test site using FGD Norit Darco activated carbon. ACI rates ranged from about 0.9 lb AC/million actual cubic feet (acf) to about 3.8 lb AC/million acf. Also shown on the figure is a least squares fit of mercury control performance as a function of ACI. The following non-linear regression equation was used to empirically fit the data.

Mercury Removal (%) = 100 – a/(ACI+b)

Where a = 44.164
b= 0.438

Details of the regression results are given at the end of this appendix.

Bituminous ACI/COHPAC Mercury Capture (Gaston Test Data)

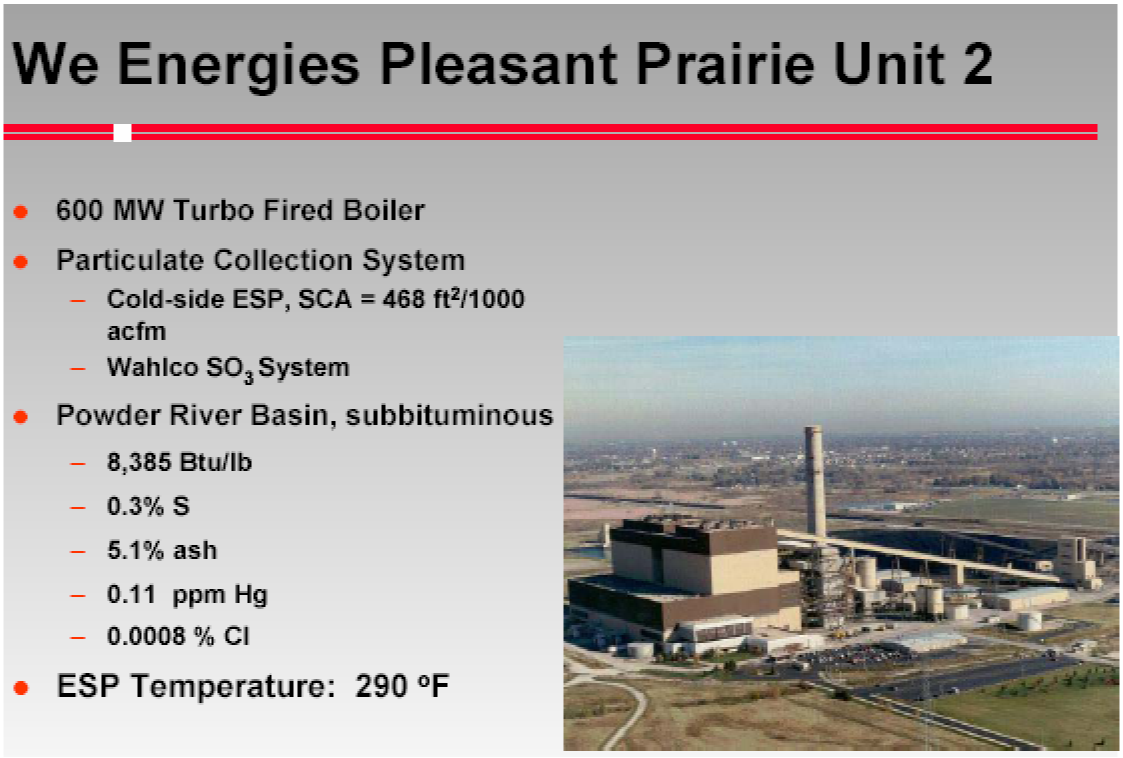


Because this is the only full-scale test of an ACI/COHPAC system in the world, the evaluation undertaken for this site represents the current understanding (with caveats) of mercury control performance using an ACI/COHPAC control system. As discussed, the lack of more test data at this and other sites makes extrapolation of information tenuous. Nevertheless, it is recognized that results from full-scale tests are more reliable than pilot scale testing of mercury control technologies.

ACI/ESP Subbituminous Coal

Mercury control performance with ACI/ESP technology was performed at the Pleasant Prairie subbituminous coal power plant. Some particulars of the test site are provided in the following graphic.

The mercury capture across the cold-side ESP was negligible at the Pleasant Prairie site. This is in agreement with the ICR data where, on average, the ICR data indicates a 3% removal of mercury by cold-side ESP's on units burning subbituminous coal. Therefore, the measurements conducted at Pleasant Prairie are consistent with average mercury removal from ICR test results and can be used directly as an indicator of mercury control performance expectations with ACI technology.

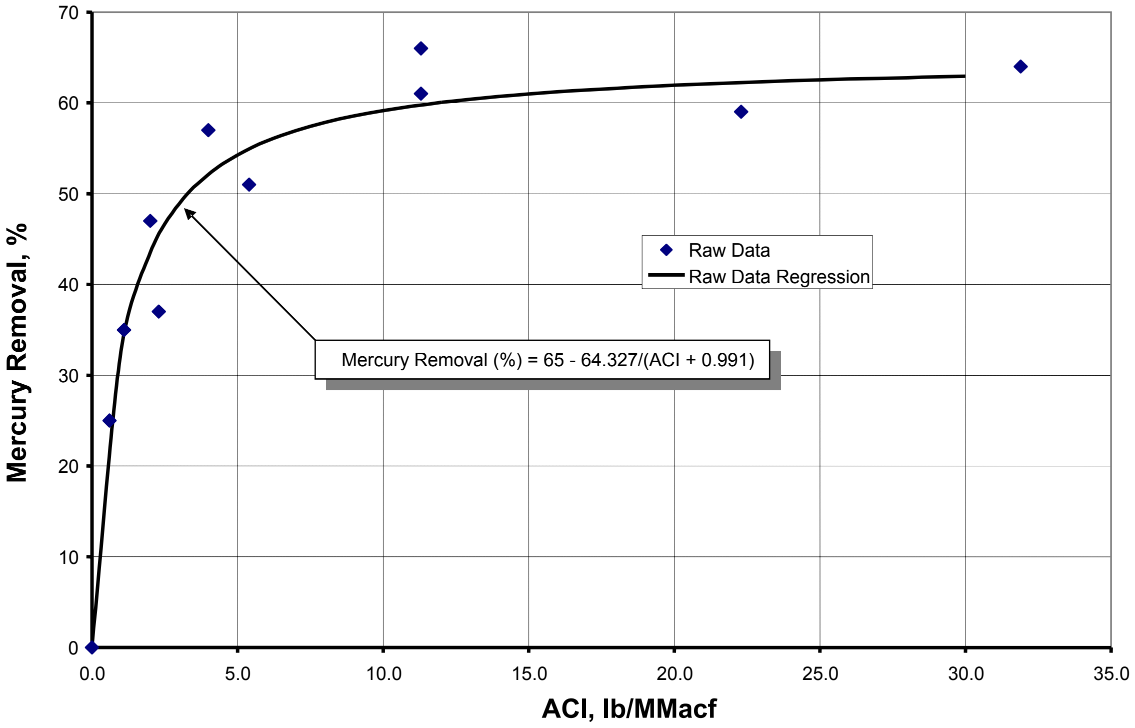


We Energies Pleasant Prairie Unit 2

- 600 MW Turbo Fired Boiler
- Particulate Collection System
  - Cold-side ESP, SCA = 468 ft^2/1000 acfm
  - Wahlco SO_3 System
- Powder River Basin, subbituminous
  - 8,385 Btu/lb
  - 0.3% S
  - 5.1% ash
  - 0.11 ppm Hg
  - 0.0008 % Cl
- ESP Temperature: 290 °F

Carbon injection performance at the Pleasant Prairie site is shown in the following figure.

Subbituminous ACI/ESP Mercury Capture (Pleasant Prairie Test Data)



Of particular note, mercury control performance reaches an asymptote at higher carbon injection rates. The curve fit suggests that a maximum mercury removal level from ACI using this configuration is about 65%.

The following non-linear regression equation was used to empirically fit the data.

Mercury Removal (%) = 65 – a/(ACI+b)

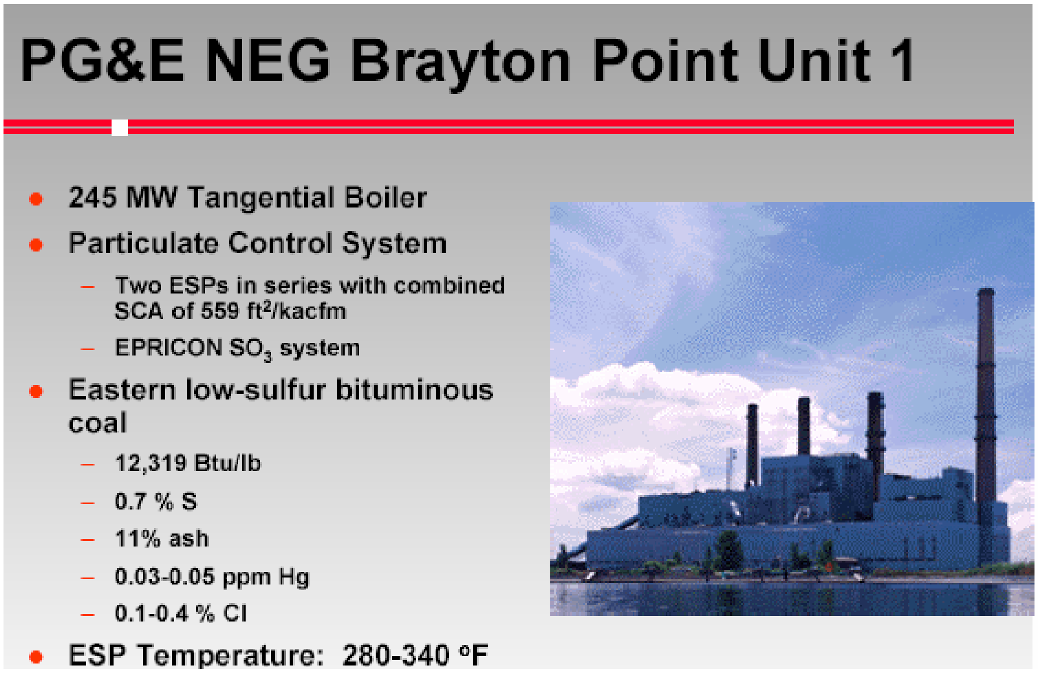
Where a = 64.327
b= 0.991

Details of the regression results are given at the end of this appendix.

The impact of enhanced mercury control as a result of lowering temperature of the flue gas before a particulate control device was also investigated at Pleasant Prairie power station. Spray water-cooling was used to lower temperatures by about 40 °F. Results of this full-scale test indicated that there was not a significant improvement in mercury removal. This observation is important since the ability to control mercury at reduced flue gas temperatures could be cost effective. However, this option appears not to be reliable based on full-scale test results to date.

ACI/ESP Bituminous Coal

Mercury control performance with ACI/ESP technology was performed at the Brayton Point bituminous coal power plant. Some particulars of the test site are provided in the following graphic.

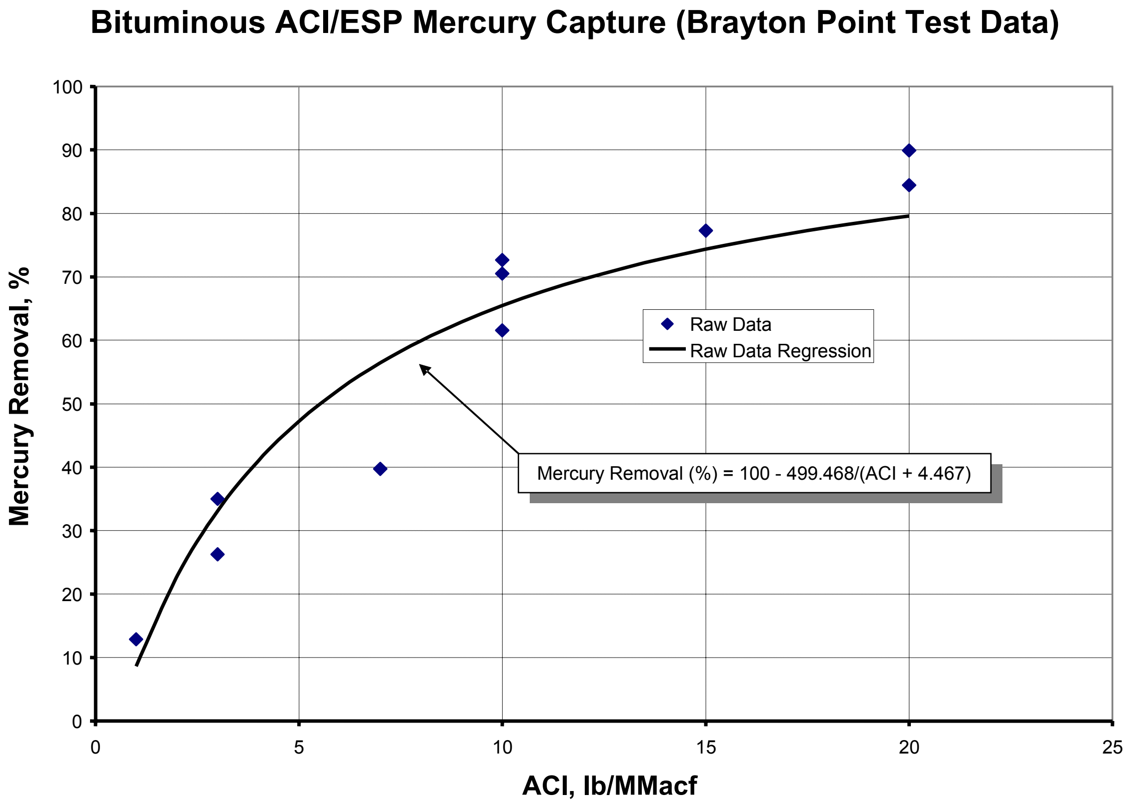


PG&E NEG Brayton Point Unit 1

- 245 MW Tangential Boiler
- Particulate Control System
  - Two ESPs in series with combined SCA of 559 ft^2/kacfm
  - EPRICON SO_3 system
- Eastern low-sulfur bituminous coal
  - 12,319 Btu/lb
  - 0.7 % S
  - 11% ash
  - 0.03-0.05 ppm Hg
  - 0.1-0.4 % Cl
- ESP Temperature: 280-340 °F

Baseline mercury removal at Brayton Point across both ESPs has been measured on several occasions in addition to being one of the tested units as part of EPA's ICR Phase III detailed facility testing. The ESP mercury co-benefit capture at Brayton Point has shown significant variability throughout the testing with Ontario-Hydro test results ranging from approximately 18% to 91%.[10,11] The test data that resulted in the highest percent reduction (91%) occurred during baseline testing prior to the carbon injection testing described here. During that baseline testing, particulate bound mercury accounted for nearly 90% of the total inlet mercury compared to an average of 37% particulate mercury at the inlet during testing for the Hg ICR where overall removal averaged 28%.

Carbon injection testing was conducted at Brayton Point Unit 1, with the AC injected downstream of the first ESP and upstream of the second ESP. Mercury capture resulting from the injected carbon was measured across the second ESP where negligible baseline mercury removal was observed without carbon injection. Because of the somewhat unique configuration of this unit in the context of generalizing the effectiveness of carbon injection into an existing ESP, it is necessary to consider the performance of ACI in the absence of native fly ash. A more detailed explanation of the inclusion of the co-benefit mercury capture of the first ESP is described in the following section.



Unlike the performance observed at Pleasant Prairie, mercury removal did not level off at activated carbon injection rates above 10 lb AC/million acf, but continued to improve as ACI rate was increased, up to the highest rate of 25 lb AC/million acf. Note that, compared to Pleasant Prairie, Brayton Point's flue gas contained much less mercury, and much more chlorine.

The following non-linear regression equation was used to empirically fit the data.

---

[10] EPA Control device analysis (http://www.epa.gov/ttn/atw/combust/utiltox/control2.zip)

[11] Starns, et.al., ***Results of Activated Carbon Injection Upstream of Electrostatic Precipitators for Mercury Control***, Presented at the AWMA Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003

Mercury Removal (%) = 100 – a/(ACI+b)

Where a = 499.468
b= 4.467

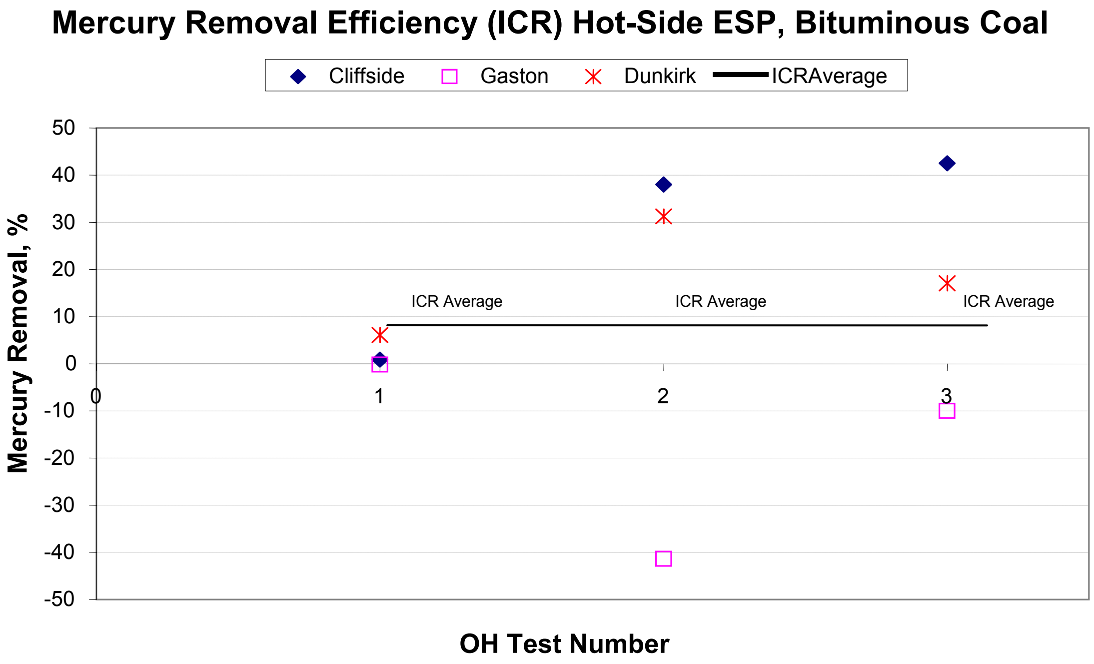
Details of the regression results are given at the end of this appendix.

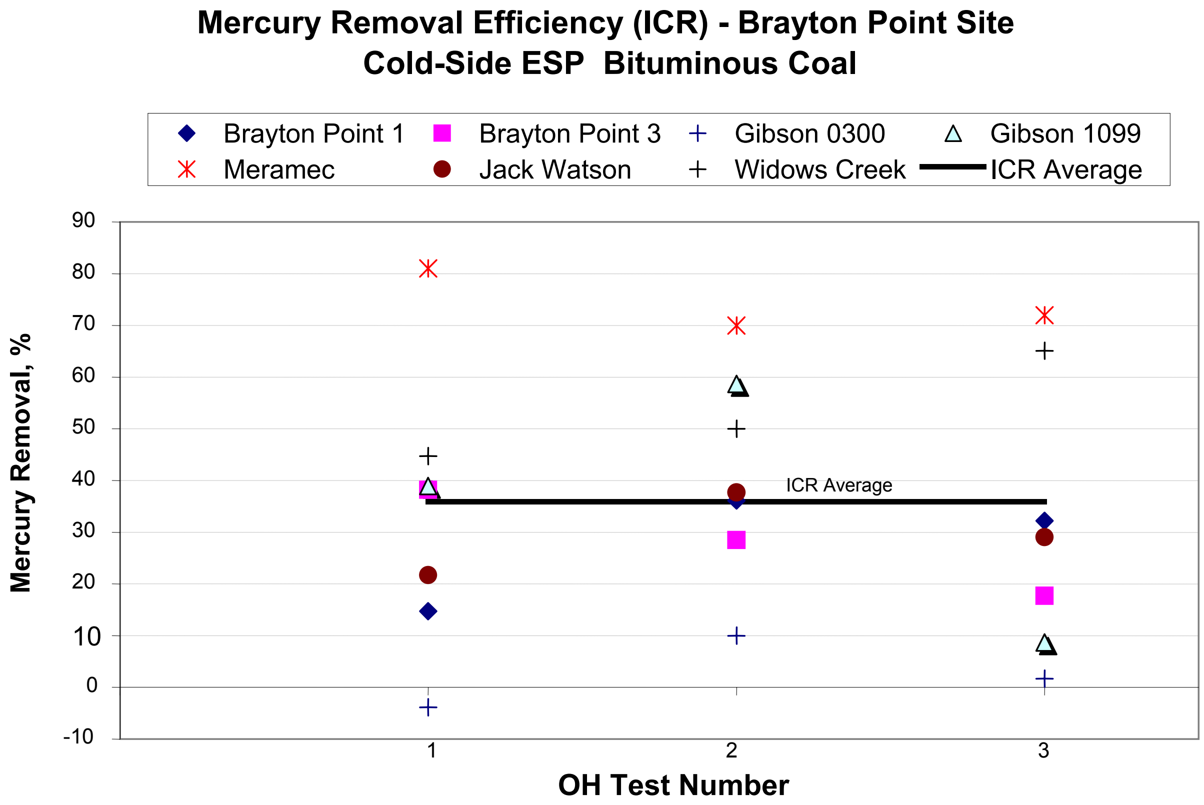
Comparison of Field Test Results with ICR Data

It is useful to examine the consistency between the baseline performance (no carbon injection) obtained from the ACI field tests and the average mercury removal of similar pollution control equipment obtained from the ICR campaign. Of the three test sites where such a comparison can be made, two of the sites, Gaston with the hot-side ESP/ pulse jet baghouse (COHPAC) configuration and Brayton Point with the dual cold-side ESP in series, exhibited significant differences in mercury capture efficiency. The baseline mercury removal efficiency at the Pleasant Prairie site, on the other hand, indicated similar mercury capture as that obtained from a similar configuration in the ICR campaign.

Adjustments to the field test data obtained at Brayton Point and Gaston can be made to improve the consistency between the baseline mercury removal efficiency and the average ICR performance. Such an adjustment enables a reasonable estimate of the performance of ACI on the general population of boilers not tested. Although there can be significant mercury removal efficiency variability for multiple test sites having a similar configuration, the average mercury control performance should be representative of typical mercury control performance for a given configuration of emissions control hardware.

The following mercury removal data from the ICR campaign is compared with baseline field-test data for mercury removal performance using ACI technology.


Mercury Removal Efficiency (ICR) Hot-Side ESP, Bituminous Coal



The variability in the mercury removal across either a hot-side ESP or cold-side ESP from the ICR campaign using bituminous coal is remarkably large. A statistical representation of the sample population is provided in the following table.

Configuration	Number	Mean	Median	St Dev	Max	Min
Cold-Side ESP	21	35.845	36.110	23.901	81.010	-3.850
Hot-Side ESP	9	9.360	6.080	26.413	42.510	-41.370

It is important to note the large standard deviations observed from the ICR data. It is clear from those large standard deviations that the co-benefit mercury capture occurring across an ESP can vary significantly, both within a plant and across different plants with similar pollution control devices. This variability is also true for the co-benefit mercury capture of most other air pollution control devices that were included in the mercury ICR. Because the specific kinetics and mechanisms of co-benefit mercury capture is not clearly understood, these attempts at quantifying the behavior of a hypothetical average performing unit are useful in developing estimates of an "ICR average" performing unit but should not be considered an accurate estimate of how a specific individual existing unit would perform.

Gaston 3

The mercury capture across the hot-side ESP during baseline ACI testing was negligible at the Gaston site. This is in agreement with the ICR test results at Gaston but is lower than the average mercury removal efficiency of 9% for all three similar units tested in the ICR program. Given the variability in the ICR test data and the relatively small magnitude of the difference between the ACI tests and the ICR tests, no adjustment for the ACI test results is deemed appropriate for ACI / COHPAC on systems with hot-side ESP's.

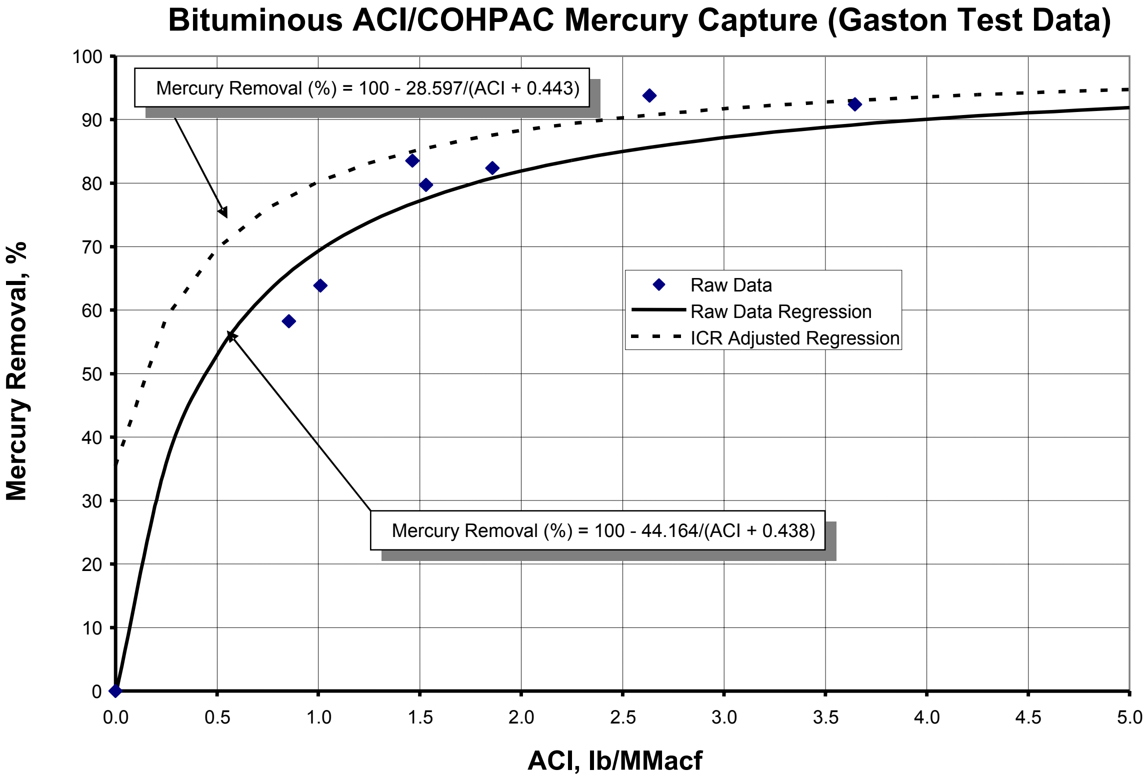
The Gaston test results were used to infer the performance of a similar ACI/COHPAC application on a power plant equipped with a cold-side ESP. The ICR data indicate the average mercury removal for a bituminous coal power plant equipped with a cold-side ESP is 36%. Such a high rate of mercury removal should be incorporated in the overall mercury removal associated with a cold-side ESP plant employing ACI/COHPAC. One approach for doing this is to employ the following expression:

Hg,c = [100-(100-36)*(100-Hg,f)/100]

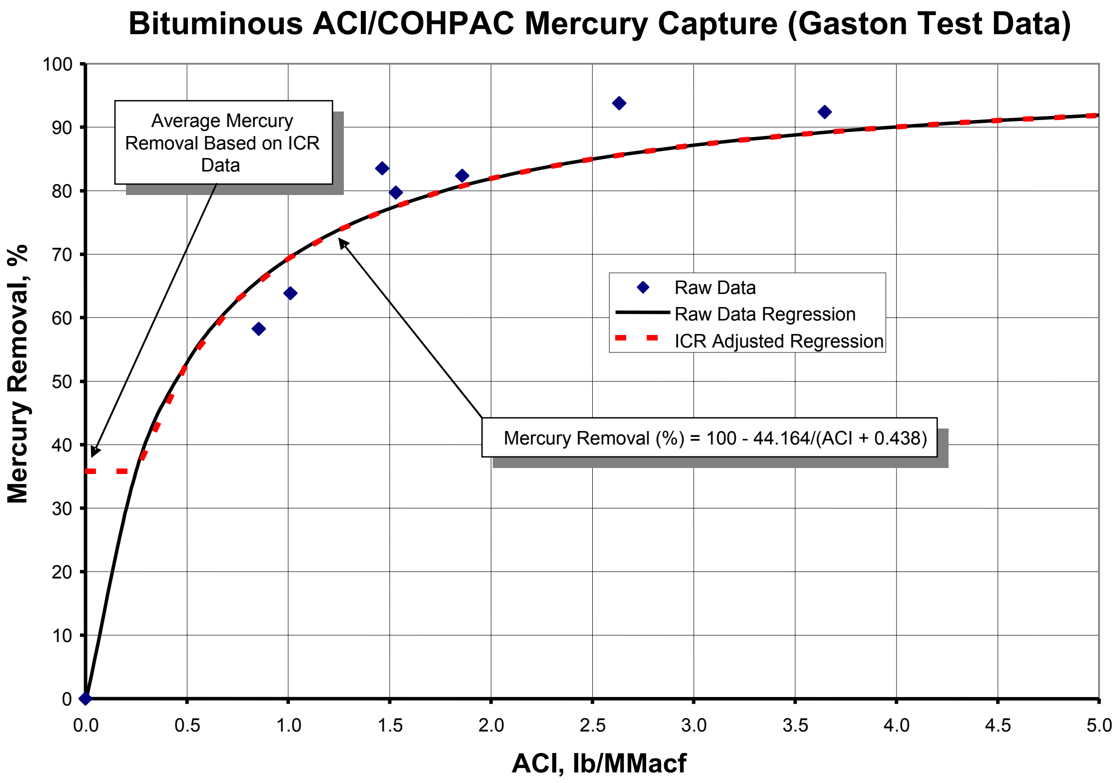
Where Hg,c is the combined estimated mercury removal across the ESP and ACI/COHPAC system and Hg,f is the fitted mercury removal calculated from test data obtained at the Gaston site. The adjusted equation is as follows:

Hg Removal (%) = 100 - 28.597/(ACI + 0.443)

The underlying assumption for this approach is that mercury removal using ACI is not a function of mercury concentration, or the depletion of other chemicals, in the flue gas. The result of the adjustment is shown in the following figure.



An alternative adjustment to estimate the mercury control performance of a cold-side ESP / FF is to assume that the ICR baseline mercury control level is maintained until ACI injection reaches a threshold value that exceeds the baseline performance level. No effect of the cold-side ESP is provided beyond this level of carbon injection. This representation of the impact of cold-side ESP is provided in the following figure.



The adjustment of the mercury performance curve only occurs at low carbon injection levels. After the ACI rate exceeds 0.25 pounds of carbon per million actual cubic feet, the adjusted curve and the original Gaston ACI performance curve fit are the same. The underlying assumption for adjusting the mercury control performance curve in this case is that activated carbon adsorption of mercury is not independent of inlet flue gas composition.

Brayton Point 1

In the baseline field tests at Brayton Point 1, the average mercury reduction was negligible. This was well below both the ICR data where a cold-side ESP removed 36% of mercury, and the ICR data for Brayton Point 1 (28% removal). However, mercury removal was measured across both of Brayton Point's ESPs in the ICR testing whereas the ACI field-testing only measured mercury removal across the downstream ESP.

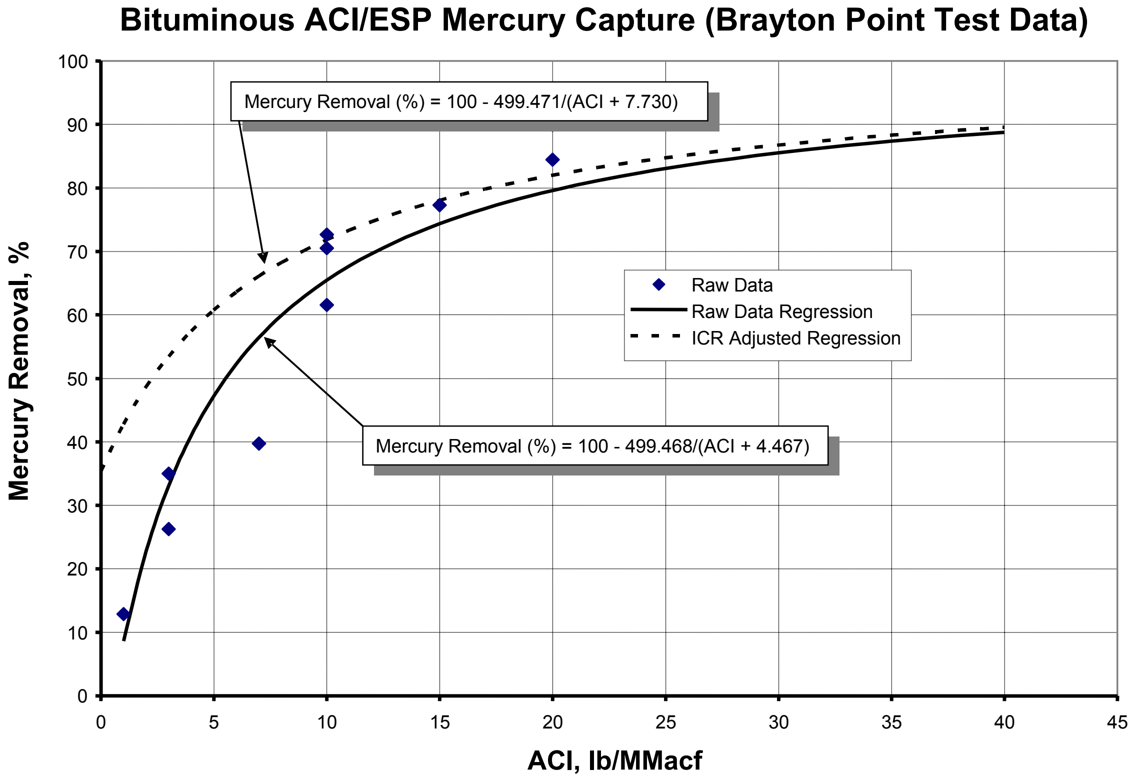
As with the Gaston results applied to cold-side ESP's, the differences in the ACI test data and the larger ICR data set are so significant that an adjustment should be made before applying the Brayton Point mercury removal results to a general situation. Similar to the Gaston data, two approaches are presented below. The first approach uses the following expression, derived from a statistical regression:

Mercury Removal (%) = 100 – a/(ACI+b)

Where a = 499.471
b= 7.730

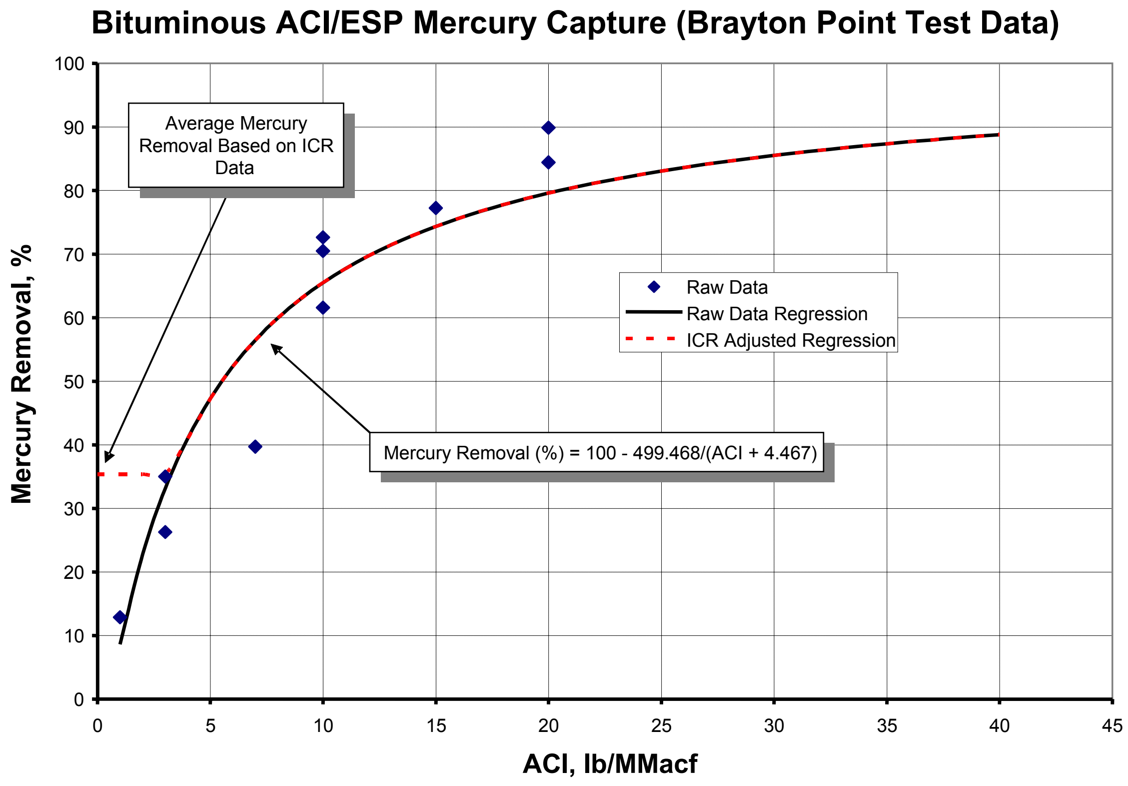
Details of the regression results are given at the end of this appendix.

The figure below provides results for the adjusted and unadjusted mercury removal performance at Brayton Point, using this first approach.



As can be seen, the adjustment for fly ash mercury control is largest at low levels of ACI and diminishes as ACI rates increase. This is intuitively appealing since the dual capture mechanism (mercury capture by fly ash and mercury capture by activated carbon) proposed here is assumed to operate in parallel.

An alternative approach to adjusting the ACI test data could be constructed, similar to the second approach used with the Gaston power plant. This adjustment assumes that certain capture-enhancing components in the flue gas are depleted as mercury is removed, limiting the ultimate amount of mercury captured by a given adsorption system. Such an assumption appears reasonable, particularly for lower chlorine coals, because the ICR data showed that cold-side ESPs on systems burning low chlorine coals (below 150 ppm) averaged less than one-half the mercury reduction of higher chlorine coals.


Bituminous ACI/ESP Mercury Capture (Brayton Point Test Data)
Average Mercury Removal Based on ICR Data
Mercury Removal (%) = 100 - 499.468/(ACI + 4.467)
Raw Data
Raw Data Regression
ICR Adjusted Regression
Mercury Removal, %
ACI, lb/MMacf
0
10
20
30
40
50
60
70
80
90
100
0
5
10
15
20
25
30
35
40
45

Regression Analysis for Full Scale ACI Mercury Control

Non-linear Regression – Bituminous COHPAC

```
All the derivatives will be calculated numerically.
_

 Iteration         Residual SS      A              B

    1              323.1677133     44.0000000     .400000000
    1.1            235.5660670     44.2445056     .436254408
    2              235.5660670     44.2445056     .436254408
    2.1            235.0650693     44.1731646     .438498780
    3              235.0650693     44.1731646     .438498780
    3.1            235.0649747     44.1633501     .438391694
    4              235.0649747     44.1633501     .438391694
    4.1            235.0649745     44.1638324     .438397673

Run stopped after 8 model evaluations and 4 derivative evaluations.
Iterations have been stopped because the relative reduction between successive residual sums of squares is at most
SSCON = 1.000E-08


Nonlinear Regression Summary Statistics     Dependent Variable VAR00002

 Source                  DF       Sum of Squares    Mean Square

 Regression              2        44685.68503       22342.84251
 Residual                6        235.06497         39.17750
 Uncorrected Total       8        44920.75000

 (Corrected Total)       7     6570.09875

 R squared = 1 - Residual SS / Corrected SS =      .96422

                                                    Asymptotic 95 %
                                  Asymptotic        Confidence Interval
 Parameter        Estimate        Std. Error        Lower             Upper

 A                44.163832367    6.171702631       29.062220056      59.265444678
 B                .438397673      .070758492        .265257880        .611537465

 Asymptotic Correlation Matrix of the Parameter Estimates

                 A         B

 A          1.0000     .9251
 B           .9251    1.0000
```

Non-linear Regression– Bituminous COHPAC ICR Adjusted 0, 36

```
All the derivatives will be calculated numerically.
_

 Iteration        Residual SS      A             B

    1             2598.000014    44.0000000    .400000000
    1.1           7.861025758    28.5318798    .424874525
    2             7.861025758    28.5318798    .424874525
    2.1           .6535227942    28.5863913    .442529222
    3             .6535227942    28.5863913    .442529222
    3.1           .6424662426    28.5970423    .443412528
    4             .6424662426    28.5970423    .443412528
    4.1           .6424662102    28.5969685    .443412417
    5             .6424662102    28.5969685    .443412417
    5.1           .6424662102    28.5969684    .443412416

Run stopped after 10 model evaluations and 5 derivative evaluations.
Iterations have been stopped because the relative reduction between successive residual sums of squares is at most
SSCON = 1.00E-08 and the relative difference between successive parameter estimates is at most PCON = 1.000E-
08


Nonlinear Regression Summary Statistics     Dependent Variable VAR00003

  Source                    DF       Sum of Squares   Mean Square

  Regression                2        53029.35525      26514.67762
  Residual                  6        .64247           .10708
  Uncorrected Total         8        53029.99771

  (Corrected Total)      7     2385.21175

  R squared = 1 - Residual SS / Corrected SS =     .99973

                                                      Asymptotic 95 %
                                     Asymptotic       Confidence Interval
  Parameter       Estimate           Std. Error       Lower            Upper

  A               28.596968470       .324641127       27.802600250     29.391336691
  B               .443412417         .005824591       .429160156       .457664677

  Asymptotic Correlation Matrix of the Parameter Estimates

                A        B

  A          1.0000    .9246
  B           .9246   1.0000
```

Non-linear Regression – Subbituminous CS-ESP

```
All the derivatives will be calculated numerically.
_

 Iteration        Residual SS      A              B

    1             2263.018766      44.0000000     .400000000
    1.1           489.1589077      53.6357298     .652433460
    2             489.1589077      53.6357298     .652433460
    2.1           196.4663838      61.1638423     .882343910
    3             196.4663838      61.1638423     .882343910
    3.1           175.8940418      64.0359484     .980223976
    4             175.8940418      64.0359484     .980223976
    4.1           175.7001050      64.3253411     .991041609
    5             175.7001050      64.3253411     .991041609
    5.1           175.7000865      64.3270639     .991130770
    6             175.7000865      64.3270639     .991130770
    6.1           175.7000865      64.3270540     .991130572

Run stopped after 12 model evaluations and 6 derivative evaluations.
Iterations have been stopped because the relative reduction between successive residual sums of squares is at most
SSCON = 1.000E-08


Nonlinear Regression Summary Statistics     Dependent Variable VAR00005

  Source                 DF       Sum of Squares   Mean Square

  Regression             2        26756.29991      13378.14996
  Residual               9        175.70009        19.52223
  Uncorrected Total      11       26932.00000

  (Corrected Total)      10     4022.54545

  R squared = 1 - Residual SS / Corrected SS =      .95632

                                                   Asymptotic 95 %
                                  Asymptotic       Confidence Interval
  Parameter        Estimate       Std. Error       Lower            Upper

  A                64.327054018   9.059067078      43.834020539     84.820087497
  B                .991130572     .173586531       .598450558       1.383810586

  Asymptotic Correlation Matrix of the Parameter Estimates

                A         B

  A          1.0000     .9362
  B           .9362    1.0000
```

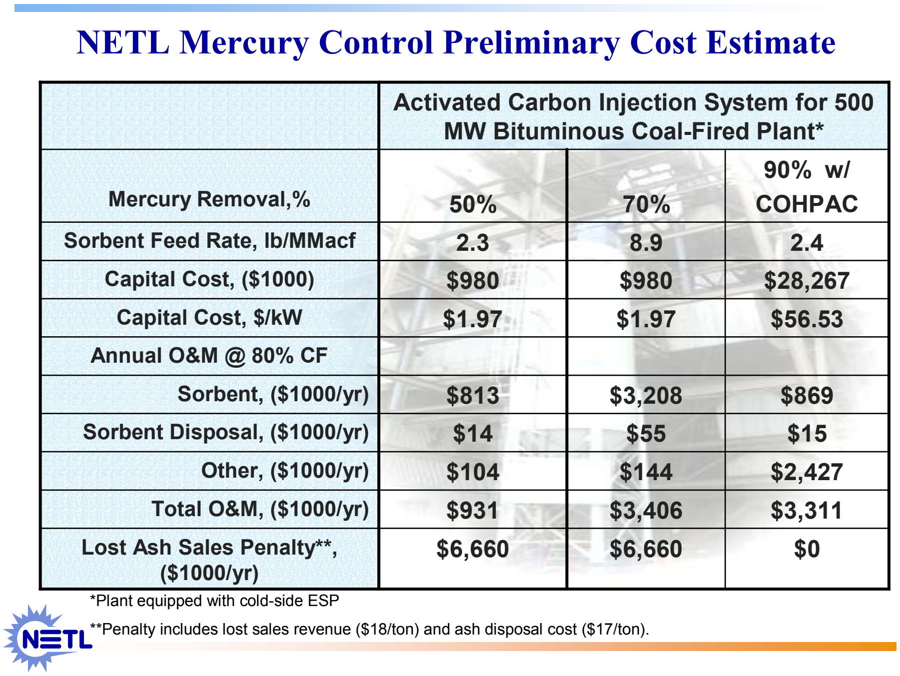
Non-linear Regression – Bituminous CS-ESP

```
All the derivatives will be calculated numerically.
_

 Iteration         Residual SS      A               B

    1              15430.05949     44.0000000      .400000000
    1.1            6829.859973     351.371915      7.76189436
    2              6829.859973     351.371915      7.76189436
    2.1            888612.9639     398.356671      -2.4159762
    2.2            2908.189441     398.726134      5.65474940
    3              2908.189441     398.726134      5.65474940
    3.1            977.9920297     478.149218      3.42672808
    4              977.9920297     478.149218      3.42672808
    4.1            575.6567694     500.790418      4.35823028
    5              575.6567694     500.790418      4.35823028
    5.1            567.6859318     500.432827      4.47923763
    6              567.6859318     500.432827      4.47923763
    6.1            567.6750853     499.350879      4.46519387
    7              567.6750853     499.350879      4.46519387
    7.1            567.6748988     499.487739      4.46726638
    8              567.6748988     499.487739      4.46726638
    8.1            567.6748948     499.467727      4.46696322

Run stopped after 17 model evaluations and 8 derivative evaluations.
Iterations have been stopped because the relative reduction between successive residual sums of squares is at most
SSCON = 1.000E-08


Nonlinear Regression Summary Statistics     Dependent Variable VAR00007

 Source                    DF        Sum of Squares   Mean Square

 Regression                2         38260.32511      19130.16255
 Residual                  8         567.67489        70.95936
 Uncorrected Total         10        38828.00000

 (Corrected Total)      9     6338.00000

 R squared = 1 - Residual SS / Corrected SS =     .91043

                                                      Asymptotic 95 %
                                     Asymptotic       Confidence Interval
 Parameter        Estimate           Std. Error       Lower             Upper

 A                499.46772749      82.539333869     309.13168227     689.80377271
 B                4.466963222       1.181760903      1.741817692      7.192108752

 Asymptotic Correlation Matrix of the Parameter Estimates

                 A          B

 A          1.0000      .9449
 B           .9449     1.0000
```

Non-linear Regression – Bituminous CS-ESP ICR Adjusted 0, 36

```
All the derivatives will be calculated numerically.
_

 Iteration        Residual SS       A                 B

    1             30.90418658      500.000000        8.00000000
    1.1           .0679084773      499.003423        7.71192601
    2             .0679084773      499.003423        7.71192601
    2.1           .0000006137      499.468783        7.72972802
    3             .0000006137      499.468783        7.72972802
    3.1           1.5515E-16       499.470864        7.72979017
    4             1.5515E-16       499.470864        7.72979017
    4.1           8.6728E-17       499.470864        7.72979018

Run stopped after 8 model evaluations and 4 derivative evaluations.
Iterations have been stopped because the relative difference between successive parameter estimates is at most
PCON = 1.000E-08


Nonlinear Regression Summary Statistics     Dependent Variable VAR00009

  Source                    DF       Sum of Squares   Mean Square

  Regression                2        36385.86545      18192.93273
  Residual                  8        8.672800E-17     1.084100E-17
  Uncorrected Total         10       36385.86545

  (Corrected Total)      9     5090.27834

  R squared = 1 - Residual SS / Corrected SS =     1.00000

                                                      Asymptotic 95 %
                                     Asymptotic       Confidence Interval
  Parameter         Estimate         Std. Error       Lower             Upper

  A                 499.47086398     3.20516E-08      499.47086391      499.47086406
  B                 7.729790175      4.55738E-10      7.729790174       7.729790176

  Asymptotic Correlation Matrix of the Parameter Estimates

                A        B

  A          1.0000    .9447
  B           .9447   1.0000
```

Summary Slides of Control Cost Estimate



NETL Mercury Control Preliminary Cost Estimate

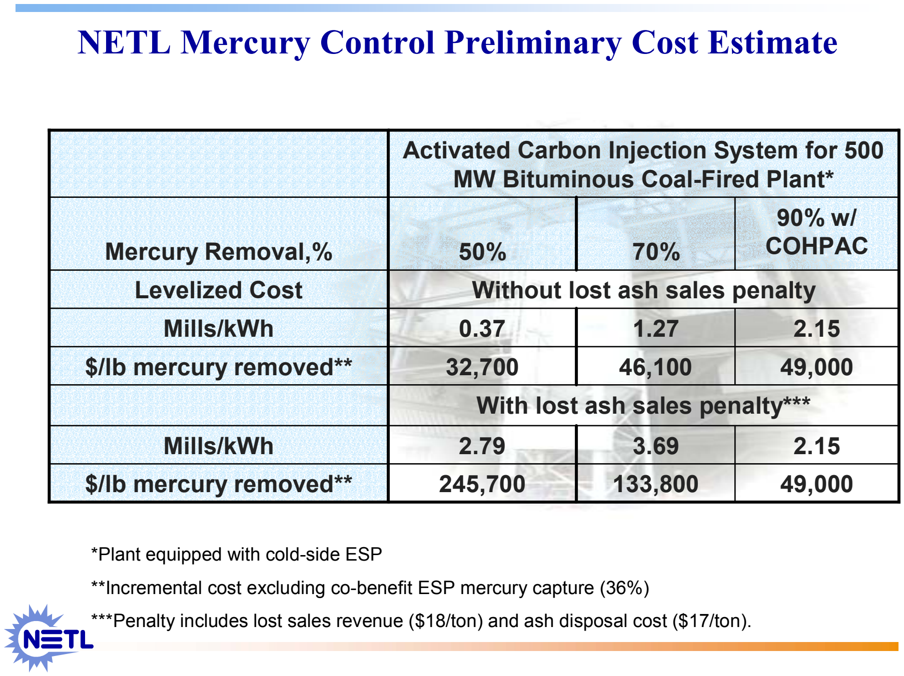
	Activated Carbon Injection System for 500 MW Bituminous Coal-Fired Plant*		
Mercury Removal,%	50%	70%	90% w/ COHPAC
Sorbent Feed Rate, lb/MMacf	2.3	8.9	2.4
Capital Cost, ($1000)	$980	$980	$28,267
Capital Cost, $/kW	$1.97	$1.97	$56.53
Annual O&M @ 80% CF			
Sorbent, ($1000/yr)	$813	$3,208	$869
Sorbent Disposal, ($1000/yr)	$14	$55	$15
Other, ($1000/yr)	$104	$144	$2,427
Total O&M, ($1000/yr)	$931	$3,406	$3,311
Lost Ash Sales Penalty**, ($1000/yr)	$6,660	$6,660	$0

*Plant equipped with cold-side ESP

**Penalty includes lost sales revenue ($18/ton) and ash disposal cost ($17/ton).

Cost & Performance Assumptions:

- Current dollar (2003$) basis, +/- 30%
- Performance based on results of ADA-ES full-scale ACI testing.
- Capital cost for sorbent injection is assumed a “per installation” cost and is not scaled with sorbent dosing rate.
- Mercury removal assumes 36% baseline removal across ESP for bituminous coal without carbon injection.
- Assumes ESP capacity adequate to handle activated carbon loading.
- Delivered activated carbon cost @ $0.50/lb
- Waste disposal cost @ $17/ton
- Lost ash sales revenue @ $18/ton
- Lost ash sales penalty @ $35/ton assumes current sale of 100% of fly ash.
- “Other” O&M includes: auxiliary power, operating labor, and equipment maintenance. COHPAC O&M includes filter bag replacement based on 5-year life.



NETL Mercury Control Preliminary Cost Estimate

	Activated Carbon Injection System for 500 MW Bituminous Coal-Fired Plant*		
Mercury Removal,%	50%	70%	90% w/ COHPAC
Levelized Cost	Without lost ash sales penalty		
Mills/kWh	0.37	1.27	2.15
$/lb mercury removed**	32,700	46,100	49,000
	With lost ash sales penalty***		
Mills/kWh	2.79	3.69	2.15
$/lb mercury removed**	245,700	133,800	49,000

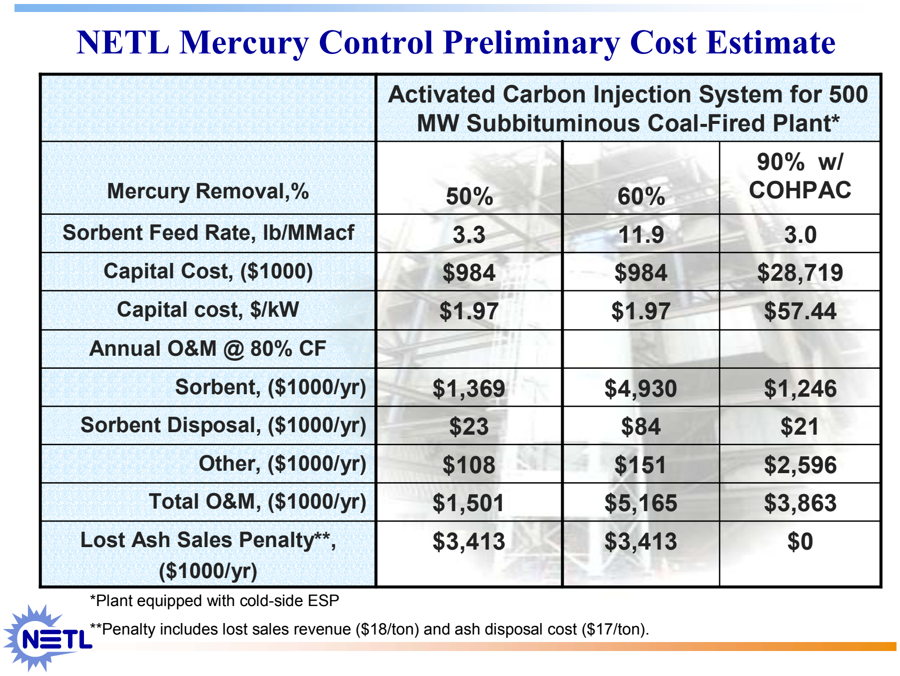
*Plant equipped with cold-side ESP

**Incremental cost excluding co-benefit ESP mercury capture (36%)

***Penalty includes lost sales revenue ($18/ton) and ash disposal cost ($17/ton).

Cost & Performance Assumptions:

- Levelized cost based on 20-year life using current year (2003$, +/- 30%) dollars escalated at 2-1/2% per year.



NETL Mercury Control Preliminary Cost Estimate

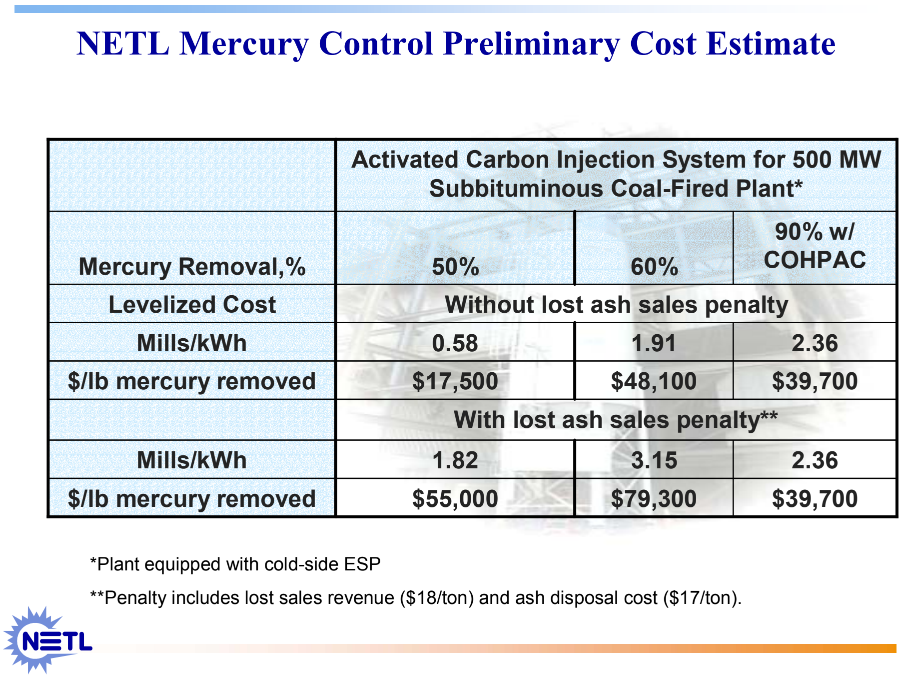
	Activated Carbon Injection System for 500 MW Subbituminous Coal-Fired Plant*		
Mercury Removal,%	50%	60%	90% w/ COHPAC
Sorbent Feed Rate, lb/MMacf	3.3	11.9	3.0
Capital Cost, ($1000)	$984	$984	$28,719
Capital cost, $/kW	$1.97	$1.97	$57.44
Annual O&M @ 80% CF			
Sorbent, ($1000/yr)	$1,369	$4,930	$1,246
Sorbent Disposal, ($1000/yr)	$23	$84	$21
Other, ($1000/yr)	$108	$151	$2,596
Total O&M, ($1000/yr)	$1,501	$5,165	$3,863
Lost Ash Sales Penalty**, ($1000/yr)	$3,413	$3,413	$0

*Plant equipped with cold-side ESP

**Penalty includes lost sales revenue ($18/ton) and ash disposal cost ($17/ton).

Cost & Performance Assumptions:

- Current dollar (2003$) basis, +/- 30%
- Performance based on results of ADA-ES full-scale ACI testing, except 90% w/ COHPAC option based on EPRI pilot plant testing.
- Capital cost for sorbent injection is assumed a “per installation” cost and is not scaled with sorbent dosing rate.
- Mercury removal assumes 0% baseline removal across ESP for subbituminous coal without carbon injection.
- Assumes ESP capacity adequate to handle activated carbon loading.
- Activated carbon cost @ $0.50/lb
- Waste disposal cost @ $17/ton
- Lost ash sales revenue @ $18/ton
- Lost ash sales penalty @ $35/ton assumes current sale of 100% of fly ash.
- “Other” O&M includes: auxiliary power, operating labor, and equipment maintenance. COHPAC O&M includes filter bag replacement based on 5-year life.



NETL Mercury Control Preliminary Cost Estimate

	Activated Carbon Injection System for 500 MW Subbituminous Coal-Fired Plant*		
Mercury Removal,%	50%	60%	90% w/ COHPAC
Levelized Cost	Without lost ash sales penalty		
Mills/kWh	0.58	1.91	2.36
$/lb mercury removed	$17,500	$48,100	$39,700
	With lost ash sales penalty**		
Mills/kWh	1.82	3.15	2.36
$/lb mercury removed	$55,000	$79,300	$39,700

*Plant equipped with cold-side ESP

**Penalty includes lost sales revenue ($18/ton) and ash disposal cost ($17/ton).

Cost & Performance Assumptions:

- Levelized cost based on 20-year life using current year (2003$, +/- 30%) dollars escalated at 2-1/2% per year.
- Because the methodology assumes no co-benefit mercury capture of the ESP for subbituminous-fired unit, the costs here are representative of the total annualized carbon injection costs (including COHPAC for the 90% reduction case) divided by total mercury capture.