DOE/NETL's Phase II Mercury Control Technology Field Testing Program

UPDATED Economic Analysis of Activated Carbon Injection

Prepared for

U.S. Department of Energy
Office of Fossil Energy
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Innovations for Existing Plants Program

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I. EXECUTIVE SUMMARY

Based on the results of Phase II full-scale field tests conducted by the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL), this report provides an update to an April 2006 economic analysis of activated carbon injection (ACI) for mercury control at coal-fired utility boilers.[1] This update includes mercury control cost estimates for the six units included in the April 2006 report plus an additional six plants: DTE Energy's Monroe Station Unit 4, Great River Energy's Stanton Station Unit 1, Progress Energy's Lee Station Unit 1, PacifiCorp's Dave Johnston Unit 3, Basin Electric's Leland Olds Unit 1, and Reliant Energy's Portland Station Unit 1. Economic factors have also been updated to develop plant-specific estimates for the 20-year levelized costs for the incremental increase in cost of electricity (COE) and the incremental cost of mercury control on a current dollar basis. Results presented in this report are grouped by the type of coal burned during Phase II full-scale field testing.

On May 18, 2005, the U.S. Environmental Protection Agency (EPA) issued a final regulation for the control of mercury emissions from coal-fired power plants.[2] The Clean Air Mercury Rule (CAMR) establishes a nationwide cap-and-trade program that will be implemented in two phases and applies to both existing and new plants. Based on 1999 estimates, U.S. coal-fired power plants emit approximately 48 tons of mercury per year.[3] As a result, CAMR requires an overall average reduction in mercury emissions of approximately 69% to meet the Phase II emissions cap. Meanwhile, several states have adopted, or are considering legislation that will impose more stringent regulations on mercury emissions from coal-fired boilers than those included in CAMR.[4]

Recognizing the potential for mercury regulation, DOE/NETL initiated comprehensive mercury research under the DOE Office of Fossil Energy's Innovations for Existing Plants (IEP) Program in the early 1990s to ensure that cost-effective and reliable pollution control technologies are available for the existing fleet of coal-fired utility boilers.[5] Currently, the program is focused on slip-stream and full-scale field testing of mercury control technologies at operating coal-fired power plants. The near-term goal is to develop mercury control technologies that can achieve 50 to 70% mercury capture at costs 25 to 50% less than baseline estimates of $50,000 to $70,000 per pound of mercury removed ($/lb Hg removed). These technologies would be available for commercial demonstration by year-end 2007 for all coal ranks. The longer-term goal is to develop advanced mercury control technologies to achieve 90% or greater capture that would be available for commercial demonstration by 2010.

In September 2003, DOE/NETL selected eight projects to test and evaluate mercury control technologies under a Phase II, Round 1 (Phase II-1) field testing solicitation. The Phase II-1 projects shown in Table 6 were initiated in 2004 and are scheduled to be completed in early-to-mid 2007. An additional six projects were subsequently awarded in October 2004 under a Phase II, Round 2 (Phase II-2) solicitation that are scheduled for completion in 2007 (Table 7). The Phase II projects focus on longer-term (~ 1 month at optimized conditions), large-scale field testing on plants burning primarily low-rank coals or blends (with some units burning bituminous coal) and equipped with a variety of air pollution control devices (APCD), and are directed at the near-term goal of 50 to 70%

mercury removal. Most of the fourteen projects fall under two general categories of mercury control – sorbent injection or oxidation enhancements. Sorbent injection generically describes the injection of powdered activated carbon (PAC) or other non-carbon sorbents into the flue gas for mercury control, while mercury oxidation enhancements are intended to improve the mercury capture efficiency of conventional ACI or downstream APCD, such as wet flue gas desulfurization (FGD), by converting elemental mercury to a more reactive oxidized state.

This report provides "study-level" cost estimates[a] for 12 of the Phase II ACI field testing sites that have been completed. This analysis was carried out to provide DOE/NETL a gauge in measuring its success in achieving the target of reducing baseline mercury control costs by 25 to 50%. Mercury control cost estimates are presented for: conventional (untreated) ACI, chemically-treated ACI, and conventional ACI coupled with the introduction of a sorbent enhancement additive (SEA) to the coal prior to combustion. Chemically-treated ACI and SEA coal treatment are intended to compensate for the lack of naturally-occurring halogens in the combustion flue gas of low-rank coals that appears to limit the mercury capture efficiency of conventional ACI. For example, total mercury removal was limited to about 65% during Phase I field testing at the Powder River Basin (PRB) subbituminous coal-fired Pleasant Prairie Unit 2, despite injection of conventional DARCO® Hg at concentrations as high as 30 pounds per million actual cubic feet (lb/MMacf) of flue gas.[6]

The economic analyses were conducted on a plant-specific basis meaning that the economics are dependent on the actual power plant operating conditions and coal properties observed during full-scale field testing at each of these Phase II sites.[b] In addition, the analyses were completed in a manner that yields the cost required to achieve low (50%), mid (70%), and high (80-90%) levels of mercury control "above and beyond" the plant-specific baseline mercury removal. In other words, the levels of mercury control discussed in this report are directly attributable to ACI. To calculate the ACI mercury removal, a data adjustment methodology was developed to account for the level of baseline mercury capture observed during parametric testing, and to incorporate the average level of mercury removal measured during the long-term continuous ACI trial. A

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[a] 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. The uncertainty of these cost estimates can be traced to the nature of DOE/NETL's Phase II field testing program and general assumptions regarding the installation and continuous operation of a full-scale PAC storage and injection system. During Phase II testing, the mercury capture efficiency of candidate PACs is measured using continuous emission monitors (CEM) that are temporarily installed for the relatively short-term field tests conducted at optimal conditions. The vapor-phase mercury measurements taken by CEM have a degree of uncertainty due to the presence of extremely low mercury concentrations in the flue gas, which makes the quality assurance and quality control (QA/QC) practices of field contractors extremely important. In terms of capital costs, this analysis includes estimates for project and process contingencies, while the cost to install and calibrate mercury monitoring equipment is excluded. The cost estimates developed here assume an uncomplicated retrofit and minimal economic impact due to the installation of the ACI system, assuming that the installation occurs during a regularly scheduled plant outage. The economics are also based on the assumption that mercury control via ACI will not cause any balance-of-plant impacts.

[b] The coal analyses and power plant parameters for each of the Phase II sites included in this study are provided in Appendix A. Full-scale field testing results are presented in Appendix B.

complete discussion of the ACI data adjustment methodology, with sample calculations, is provided in Appendix C.

This approach is complicated by the variability of baseline mercury capture caused by changes in coal composition and boiler performance that can impact the quantity of unburned carbon present in the fly ash. In addition, field testing has shown that residual PAC remaining in the ductwork from previous injection trials may contribute to an increase in baseline mercury capture over the course of the parametric testing campaign. With that in mind, a conscious effort was made to identify the baseline mercury capture observed prior to the parametric tests involving the PAC that was ultimately selected for evaluation during the long-term continuous injection trial.

Tables 1, 2, and 3 present 20-year levelized cost estimates (current $) for the Phase II units included in this analysis burning bituminous, subbituminous (PRB), and North Dakota (ND) lignite coals, respectively. Mercury control via ACI upstream of the existing particulate control device will result in commingling of the PAC and fly ash that could potentially have an adverse effect on the marketability of the fly ash. Therefore, the 20-year levelized costs for the incremental increase in COE, expressed in mills[c] per kilowatt-hour (mills/kWh), and the incremental cost of mercury control ($/lb Hg removed) are presented in Tables 1-3 both with and without the inclusion of potential byproduct impacts.[d]

Primarily, the increase in COE resulting from mercury control via ACI is determined by annual PAC consumption costs that are dependent on the required ACI rate, delivered PAC price (Table 8), and the volume of flue gas being treated. In addition to PAC chemical composition, the ACI rate required to achieve a given level of mercury control can be impacted by a host of plant-specific dynamics, including, but not limited to: chlorine and sulfur contents of the coal being burned, APCD configuration, flue gas temperature, boiler efficiency/unburned carbon, and ductwork geometry in proximity to the ACI location. For this analysis, the 20-year levelized incremental increase in COE varies from 0.15 to 4.67 mills/kWh. The lower bound corresponds to 50% ACI mercury removal via brominated DARCO® Hg-LH injection at Holcomb Station Unit 1, when byproduct impacts are excluded. The upper bound was calculated for 80% ACI mercury removal via brominated B-PAC™ injection at Lee Station Unit 1, with the inclusion of byproduct impacts.

The incremental cost of mercury reduction ($/lb Hg removed) is impacted largely by the level of baseline mercury capture exhibited by the existing APCD configuration and coal mercury content (lb/TBtu). For example, the incremental cost of mercury control will

[c] One mill is equivalent to 1/10 of a cent.

[d] For units equipped with a cold-side electrostatic precipitator (CS-ESP), the byproduct impacts incurred once the utility installs an ACI system for mercury control assume that the fly ash can no longer be sold for $18/ton; instead, the utility must pay $17/ton for non-hazardous disposal of the fly ash. For units equipped with a spray dryer absorber and fabric filter (SDA/FF) configuration, the byproduct impacts incurred by the utility assume that the SDA byproducts (i.e., SDA ash and solid calcium sulfite) can no longer be given away; instead, the utility must pay $17/ton for non-hazardous disposal of the SDA byproducts once an ACI system is installed. For this analysis, the quantity of byproduct generated was calculated by assuming the SDA/FF configuration is able to capture 90% of the sulfur dioxide present in the flue gas.

increase when: (1) baseline mercury capture is high; or (2) coal mercury content is low, because a smaller quantity of mercury is removed from the flue gas for a given level of control. For this analysis, the 20-year levelized incremental cost of mercury control varies from about $3,910 to $179,000/lb Hg removed. The lower bound was calculated for 70% ACI mercury removal at Holcomb Station Unit 1, when byproduct impacts are excluded. The upper bound corresponds to 50% ACI mercury removal at Lee Station Unit 1, with the inclusion of byproduct impacts.

The following sections delve into the mercury control cost estimates for each coal rank. Note that Monroe Station Unit 4, which typically fires a 60% PRB and 40% bituminous coal blend, is included in the bituminous fraction, while St. Clair Unit 1, which normally burns an 85% PRB and 15% bituminous coal blend, is grouped with the PRB units.

Bituminous Coal-Fired Units

As shown in Table 1, this analysis provides plant-specific cost estimates for different levels of ACI mercury control based on the performance of: (1) conventional Super HOK injection at Plant Yates Unit 1; (2) conventional DARCO® Hg injection at Monroe Station Unit 4; (3) brominated B-PAC™ injection at Lee Station Unit 1; and (4) chemically-treated Mer-Clean™ 8-21 injection at Portland Station Unit 1. For these ACI systems, the total capital requirement (TCR) values expressed as a function of unit capacity range from $3.82/kW for the 785 MW Monroe Station Unit 4 to $16.02/kW for the 79 MW Lee Station Unit 1.

For 70% ACI mercury removal with no byproduct impacts, the increase in COE ranges from 0.69 to 1.95 mills/kWh, while the incremental cost varies from about $14,900 to $87,200/lb Hg removed for Portland and Lee, respectively. The incremental costs for Yates and Lee are noticeably higher than the estimates provided for 70% ACI mercury removal at Monroe and Portland. The high incremental costs are a consequence of two important plant-specific factors: the low mercury content (3.35 lb/TBtu) of the bituminous coal burned at Lee, and the 50% baseline mercury removal observed during Phase II testing at Yates, which reduce the quantity of mercury that is removed for a given level of ACI mercury control. With the inclusion of byproduct impacts, the increase in COE ranges from 1.84 to 3.66 mills/kWh, while the incremental cost of 70% ACI mercury removal varies from about $39,600 to $164,000/lb Hg removed.

For 80% ACI mercury removal at Monroe, injection of DARCO® Hg at 5.78 lb/MMacf yields an increase in COE of 1.20 mills/kWh and an incremental cost of about $33,800/lb Hg removed, when byproduct impacts are excluded. For 80% ACI mercury removal at Lee, a B-PAC™ injection rate of 8.27 lb/MMacf results in an increase in COE of 2.95 mills/kWh and an incremental cost of about $103,000/lb Hg removed, when byproduct impacts are excluded. The economics of 90% ACI mercury removal at Portland were also tabulated. Based on Mer-Clean™ 8-21 injection at 5.34 lb/MMacf, the increase in COE for Portland is 1.94 mills/kWh and incremental cost of 90% ACI mercury removal is approximately $32,300/lb Hg removed, when byproduct impacts are excluded. When byproduct impacts are included, the increase in COE for 90% ACI mercury removal at Portland is 3.09 mills/kWh, while the incremental cost is about $51,500/lb Hg removed.

PRB Coal-Fired Units

Table 2 provides 20-year levelized cost estimates for low (50%), mid (70%), and high (90%) levels of ACI mercury control based on the performance of: (1) brominated DARCO® Hg-LH injection at Holcomb Station Unit 1 and Meramec Station Unit 2; (2) brominated B-PAC™ injection at St. Clair Station Unit 1 and Stanton Station Unit 1; and (3) chemically-treated Mer-Clean™ 8 injection at Dave Johnston Unit 3. For these ACI systems, the TCR values expressed as a function of unit capacity range from $3.63/kW for the 360 MW Holcomb Station Unit 1 to $9.16/kW for the 140 MW Meramec Station Unit 2.

For 90% ACI mercury removal across a CS-ESP with no byproduct impacts, the increase in COE ranges from 0.46 to 1.29 mills/kWh, while the incremental cost varies from about $7,190 to $30,500/lb Hg removed for Dave Johnston and Stanton Unit 1, respectively. The 20-year levelized costs presented for St. Clair (1.16 mills/kWh; $28,500/lb Hg removed) are higher than the values calculated for Meramec (0.99 mills/kWh; $17,800/lb Hg removed) due to plant-specific factors such as flue gas flow rate and coal mercury content. Likewise, the incremental cost of 90% ACI mercury removal presented for Stanton Unit 1 is impacted by a low coal mercury content of about 5.50 lb/TBtu. For 90% ACI mercury removal across the SDA/FF configuration at Holcomb, the increase in COE is 0.37 mills/kWh and incremental cost is about $6,090/lb Hg removed, when byproduct impacts are excluded. With the inclusion of byproduct impacts, the increase in COE resulting from 90% ACI mercury removal at these PRB units ranges from 1.08 to 2.35 mills/kWh, while the incremental cost varies from $17,900 to $52,500/lb Hg removed.

Note that the incremental cost of 70% ACI mercury removal at each of these five units is lower than the value calculated for 50% ACI control. This trend occurs when the increase in mass of mercury captured outpaces the increased cost of control. For these units, the chemically-treated ACI rate needed to improve from 50 to 70% ACI mercury removal ranges from about 0.10 to 0.50 lb/MMacf leading to a small incremental increase in the cost of mercury control.

ND Lignite Coal-Fired Units

As shown in Table 3, this analysis provides plant-specific cost estimates for different levels of ACI mercury control based on the performance of: (1) conventional DARCO® Hg injection, coupled with SEA coal treatment, at Leland Olds Unit 1; (2) brominated DARCO® Hg-LH injection at Stanton Station Unit 10; and (3) chemically-treated Mer-Clean™ 8 injection at Leland Olds Unit 1. For these ACI systems, the TCR values expressed as a function of unit capacity range from $6.45/kW for the 220 MW Leland Olds Unit 1 to $21.10/kW for the 60 MW Stanton Station Unit 10. Note that the TCR for Leland Olds includes $125,000 for the installation of an SEA storage and injection system.

For 70% ACI mercury removal at Leland Olds with no byproduct impacts, the increase in COE is 0.42 and 1.21 mills/kWh, while the incremental cost is about $7,400 and $21,500/lb Hg removed for Mer-Clean™ 8 injection and conventional DARCO® Hg injection with SEA coal treatment, respectively. For Stanton Unit 10, the increase in COE is 1.05 mills/kWh and the incremental cost of 70% ACI mercury removal is about $17,900. With the inclusion of byproduct impacts, the increase in COE ranges from 2.78

to 3.84 mills/kWh, while the incremental cost of 70% ACI mercury removal varies from about $47,300 to $68,200/lb Hg removed.

For 80% ACI mercury removal at Leland Olds, injection of DARCO® Hg at 8.65 lb/MMacf, coupled with SEA coal treatment, yields an increase in COE of 1.81 mills/kWh and an incremental cost of about $24,900/lb Hg removed, when byproduct impacts are excluded. For 80% ACI mercury removal at Stanton Unit 10, a DARCO® Hg-LH injection rate of 1.98 lb/MMacf results in an increase in COE of 1.30 mills/kWh and an incremental cost of about $17,300/lb Hg removed, when byproduct impacts are excluded. An economic analysis of 90% ACI mercury removal via Mer-Clean™ 8 injection at Leland Olds was also performed. Based on Mer-Clean™ 8 injection at 1.64 lb/MMacf, the increase in COE for Leland Olds is 0.91 mills/kWh and incremental cost of 90% ACI mercury removal is approximately $12,600/lb Hg removed, when byproduct impacts are excluded. When byproduct impacts are included, the increase in COE for 90% ACI mercury removal at Leland Olds is 3.54 mills/kWh, while the incremental cost is about $48,900/lb Hg removed.

The preliminary Phase II field testing results are very encouraging both in terms of the level of mercury removal achieved and the levelized cost of control on a mills/kWh and $/lb Hg removed basis. Specifically, the economics of mercury control via chemically-treated ACI at units burning lower-rank PRB and lignite coals is noteworthy. The 20-year levelized incremental increase in COE for 90% ACI mercury removal via chemically-treated or brominated PAC injection remains below 1.30 mills/kWh for the four PRB units, St. Clair, and Leland Olds, when byproducts impacts are excluded. For comparison, the increase in COE calculated for 90% ACI mercury removal at the bituminous-fired Portland Station is over 1.90 mills/kWh, when byproduct are excluded.

However, it must be kept in mind that the field tests still represent relatively short-term testing at optimum conditions. While such testing provides a sound basis for evaluating performance and cost, the limited duration of the testing does not allow for a comprehensive assessment of several key operational and balance-of-plant issues associated with ACI in general and the use of chemically-treated PAC and SEA specifically. These include: (1) changes in coal characteristics (e.g., mercury and chlorine content); (2) changes in load; (3) impacts on small collection area ESPs; (4) PAC carryover into downstream APCD; (5) corrosion issues; (6) potential off-gassing of bromine compounds; (7) formation of flue gas halides; and (8) leaching from brominated PAC byproducts.

It should also be noted that the economic analyses represent “snapshots” in time based on the methodology used, assumptions made, and conditions that were specific to the time when DOE/NETL field testing occurred. Consequently, the economics presented in this report are plant and condition specific and attempts to use this document as a tool to predict the performance of the mercury control technologies described in this report at other power plants should be conducted cautiously regardless of similarities in coal rank and APCD configuration. In addition, the economics originate from relatively small datasets in many cases. As a result, the cost of mercury control could vary significantly with the inclusion of additional ACI performance data from current and future DOE/NETL field testing.

Table 1 -- 20-Year Levelized Cost of Mercury Control for Bituminous Units

Plant	Byproduct Impacts	50%			70%			80- 90%[e]		
		ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed	ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed	ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed
Yates Unit 1 (Super HOK)	without	3.85	0.98	$55,200	8.98	1.72	$69,500	N/A		
	with		2.92	$165,000		3.66	$148,000			
Monroe Unit 4 (DARCO® Hg)	without	1.46	0.38	$17,200	3.38	0.75	$24,000	5.78	1.20	$33,800
	with		1.62	$73,100		1.99	$63,900		2.45	$68,800
Lee Unit 1 (B-PAC™)	without	2.07	1.14	$71,400	4.83	1.95	$87,200	8.27	2.95	$103,000
	with		2.85	$179,000		3.66	$164,000		4.67	$163,000
Portland Unit 1 (Mer-Clean™ 8-21)	without	0.59	0.45	$13,400	1.39	0.69	$14,900	5.34	1.94	$32,300
	with		1.60	$47,900		1.84	$39,600		3.09	$51,500

Table 2 -- 20-Year Levelized Cost of Mercury Control for PRB Units

Plant	Byproduct Impacts	50%			70%			90%		
		ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed	ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed	ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed
Holcomb Unit 1 (DARCO® Hg-LH)	without	0.11	0.15	$4,380	0.27	0.18	$3,910	1.03	0.37	$6,090
	with		0.86	$25,600		0.89	$19,000		1.08	$17,900
St. Clair Unit 1 (B-PAC™)	without	0.26	0.39	$17,200	0.60	0.52	$16,300	2.31	1.16	$28,500
	with		1.36	$60,500		1.49	$47,200		2.13	$52,500
Meramec Unit 2 (DARCO® Hg-LH)	without	0.27	0.38	$12,200	0.62	0.48	$11,100	2.40	0.99	$17,800
	with		1.74	$56,100		1.84	$42,400		2.35	$42,100
Dave Johnston Unit 3 (Mer-Clean™ 8)	without	0.06	0.26	$7,440	0.14	0.30	$5,970	0.55	0.46	$7,190
	with		1.55	$44,000		1.59	$32,100		1.75	$27,500
Stanton Unit 1 (B-PAC™)	without	0.41	0.39	$16,700	0.95	0.54	$16,500	3.65	1.29	$30,500
	with		1.07	$45,400		1.22	$36,900		1.97	$46,400

Table 3 - 20-Year Levelized Cost of Mercury Control for ND Lignite Units

Plant	Byproduct Impacts	50%			70%			80- 90%[f]		
		ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed	ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed	ACI, lb/MMacf	COE Increase, mills/kWh	$/lb Hg Removed
Leland Olds Unit 1 (DARCO® Hg & $CaCl_2$)	without	2.15	0.74	$18,300	5.04	1.21	$21,500	8.65	1.81	$24,900
	with		3.37	$83,600		3.84	$68,200		4.44	$61,200
Stanton Unit 10 (DARCO® Hg-LH)	without	0.49	0.85	$20,300	1.15	1.05	$17,900	1.98	1.30	$17,300
	with		2.58	$61,500		2.78	$47,300		3.03	$40,100
Leland Olds Unit 1 (Mer-Clean™ 8)	without	0.18	0.32	$7,900	0.42	0.42	$7,400	1.64	0.91	$12,600
	with		2.95	$73,200		3.05	$54,100		3.54	$48,900

[e] Table 1 displays economic data for 80% ACI mercury removal at Monroe and Lee, and 90% ACI mercury removal at Portland.
[f] Table 3 displays economic data for 80% ACI mercury removal at Leland Olds and Stanton 10, and 90% ACI mercury removal via Mer-Clean™ 8 injection at Leland Olds.

II. INTRODUCTION

On May 18, 2005, EPA issued a final regulation for the control of mercury emissions from coal-fired power plants. CAMR establishes a nationwide cap-and-trade program that will be implemented in two phases and applies to both existing and new plants. The first phase of control begins in 2010 with a 38 ton mercury emissions cap based largely on “co-benefit” reductions achieved through further sulfur dioxide (SO_2) and nitrogen oxides (NOx) emission controls required under EPA’s recently issued Clean Air Interstate Rule (CAIR). The second phase of control requires a 15 ton mercury emissions cap beginning in 2018. Based on 1999 estimates, U.S. coal-fired power plants emit approximately 48 tons of mercury per year. As a result, CAMR requires an overall average reduction in mercury emissions of approximately 69% to meet the Phase II emissions cap. Meanwhile, several states have adopted, or are considering legislation that will impose more stringent regulations on mercury emissions from coal-fired boilers than those included in CAMR.

Recognizing the potential for mercury regulation, DOE/NETL initiated comprehensive mercury research under the DOE Office of Fossil Energy’s IEP Program in the early 1990s to ensure that cost-effective and reliable pollution control technologies are available for the existing fleet of coal-fired utility boilers. Working collaboratively with power plant operators, the Electric Power Research Institute (EPRI), academia, state and local agencies, and EPA, the IEP Program has greatly advanced our understanding of the formation and capture of mercury from coal-fired power plants. Initial efforts were directed at characterizing power plant mercury emissions and focused on laboratory- and bench-scale control technology development. The current IEP Program is focused on slip-stream and full-scale field testing of mercury control technologies, as well as continued bench- and pilot-scale development of novel control concepts. The results of completed full-scale field testing efforts are discussed in more detail in later sections. The near-term program goal is to develop mercury control technologies that can achieve 50 to 70% mercury capture at costs 25 to 50% less than baseline (1999) estimates of $50,000 to $70,000/lb of mercury removed. These technologies would be available for commercial demonstration by year-end 2007 for all coal ranks. The longer-term goal is to develop advanced mercury control technologies to achieve 90% or greater capture that would be available for commercial demonstration by 2010. Under DOE’s Clean Coal Demonstration Program, DOE is also carrying out the first-of-a-kind commercial demonstration of mercury control technology at WeEnergies’ Presque Isle Power Plant in Marquette, Michigan.[7]

Previous testing has demonstrated that some degree of co-benefit mercury control is achieved by existing APCD installed to control NOx, SO_2, and particulate matter (PM) emissions from coal-fired power plant combustion flue gas. However, mercury capture across existing APCD can vary significantly based on coal properties, fly ash properties (including unburned carbon), specific APCD configurations, and other factors, with the level of control ranging from 0% to more than 90%. Mercury is present in the flue gas in varying percentages of three basic chemical forms: particulate-bound mercury, oxidized mercury, and elemental mercury. The term speciation is used to describe the relative proportion of the three forms of mercury in the flue gas. Mercury speciation has a large affect on co-benefit mercury control by existing APCD. For example, elemental mercury is not readily captured by existing APCD, while particulate-bound mercury is captured by ESP and FF. Oxidized mercury is water-soluble and therefore readily captured in wet FGD systems.

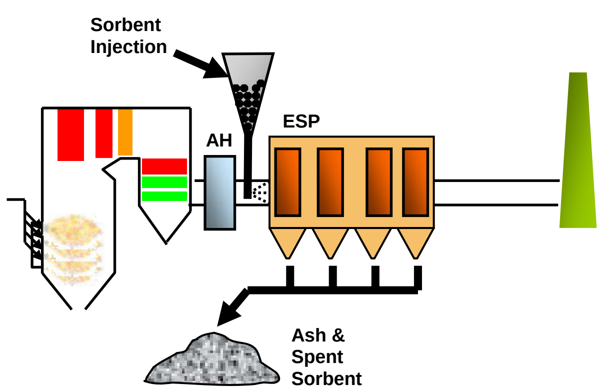
In general, plants burning PRB and lignite coals demonstrate significantly lower co-benefit mercury capture than similarly equipped bituminous-fired plants. The lower native removal observed for these low-rank coals has been linked to higher levels of elemental mercury, associated with the coal's low chlorine content. For units equipped with an SDA/FF configuration, the reduced co-benefit mercury capture observed at units burning lower-rank coals can be attributed to chlorine capture across the SDA that leads to inadequate chlorine levels at the FF to participate in the oxidation and capture of elemental mercury.[8] Table 4 presents a summary of average co-benefit mercury capture for the APCD configurations and coal ranks analyzed in this report. The Information Collection Request (ICR) data was collected by EPA in 1999.[3]

Table 4 -- Average Co-benefit Mercury Capture from EPA ICR Database[g]

APCD Configuration	Average Percentage Mercury Capture			
	Bituminous	**PRB/Bit. Blend**	**PRB**	**Lignite**
CS-ESP	36 %	21 %	3 %	- 4 %
SDA/FF	98 %	N/A	24 %	0 %

Although existing APCD can capture some mercury, innovative control technologies will be needed to comply with the CAMR Phase II mercury emission cap. To date, ACI has shown the most promise as a near-term mercury control technology. In a typical configuration, PAC is injected downstream of the plants' air heater and upstream of the existing particulate control device – either an ESP or FF (Figure 1). The PAC adsorbs the mercury from the combustion flue gas and is subsequently captured along with the fly ash in an ESP or FF. Although initial field testing of ACI has been relatively successful, additional research, development and demonstration (RD&D) activities are required before it is considered a commercial technology for the broad range of coals burned by, and various APCD installed on, today's coal-fired power plants. For example, the effect of continuous long-term ACI on plant operations has yet to be fully determined.

Figure 1 -- Activated Carbon Injection Technology Schematic



[g] The negative value presented for a lignite-fired plant equipped with a CS-ESP is suspected to be a function of mercury measurement limitations.

Phase I – Field Testing of Activated Carbon Injection

Through research funded by DOE/NETL, ADA Environmental Solutions (ADA-ES) evaluated the mercury capture efficiency of conventional (untreated) ACI at four coal-fired electric utility boilers during field testing conducted in 2001-2002. These Phase I ACI field tests were directed at the IEP Program's near-term goal of 50 to 70% mercury removal. The testing at each plant included parametric tests using several commercially available PACs at various feed rates and operating conditions followed by a one- to two-week, optimized long-term test with a PAC selected from the parametric testing campaign. Testing was carried out sequentially at the four host sites described in Table 5.[6,9,10,11]

Table 5 -- Description of Phase I ACI Field Testing Sites

Utility Company	Plant	Coal Rank	APCD Configuration	Date Test Completed
Alabama Power	E.C. Gaston Unit 3	Bituminous	Hot-side ESP and COHPAC™ FF	April 2001
We Energies	Pleasant Prairie Unit 2	PRB	CS-ESP	November 2001
PG&E	Brayton Point Unit 1	Bituminous	CS-ESP	August 2002
PG&E	Salem Harbor Unit 1	Bituminous	CS-ESP and SNCR	November 2002

DOE/NETL used the Phase I field testing results to complete an economic evaluation of mercury control via ACI in 2003.[12] The economic analysis was based on total mercury removal at representative 500 MW bituminous- and PRB-fired units that exhibit baseline mercury removal consistent with the average values observed during EPA's ICR campaign (Table 4). Results from the earlier cost study led to the conclusion that the three most important factors affecting the economics of ACI are: (1) PAC consumption; (2) impact to byproduct management and disposal practices; and (3) capital costs associated with the installation of a compact hybrid particulate collector (COHPAC™) FF for the toxic emission control (TOXECON™) configuration.

The analysis also revealed that conventional ACI upstream of an existing CS-ESP is not a cost-effective option for 90% total mercury removal at bituminous- and PRB-fired power plants. In fact, mercury capture reached a maximum asymptote of approximately 65% for the PRB-fired unit regardless of the ACI concentration. Although 90% mercury removal via conventional ACI upstream of the existing CS-ESP was theoretically possible for the representative bituminous-fired power plant, the previous study showed that ACI downstream of the existing ESP and upstream of a retrofitted COHPAC™ FF (i.e., TOXECON™) was more economical despite the higher capital cost associated with the installation of the COHPAC™ FF. The TOXECON™ configuration also offers the inherent benefit that there would be no additional costs for fly ash disposal or loss of revenue from sale, because fly ash is collected in ESP hoppers upstream of the ACI location. From an incremental cost ($/lb Hg removed) perspective, mercury control at PRB-fired units appeared to be more cost-effective than at bituminous-fired units. This was caused by the higher incremental mercury removal attributed to ACI at a PRB-fired unit due to the assumption of 0% baseline mercury capture across the CS-ESP.

Phase II – Longer-Term Field Testing of Activated Carbon Injection

In further support of the near-term IEP program goal, DOE/NETL selected eight new projects in September 2003 to test and evaluate mercury control technologies under a Phase II, Round 1 (Phase II-1) field testing solicitation. The Phase II-1 projects shown in Table 6 were initiated in 2004 and are scheduled to be completed in early-to-mid 2007. An additional six projects – representing seven technologies[h] - were subsequently awarded in October 2004 under a Phase II, Round 2 (Phase II-2) solicitation that are scheduled for completion by year-end 2007 (Table 7). Building on promising advances that resulted from the Phase I field testing program, the Phase II projects focus on longer-term (~ 1 month at optimized conditions), large-scale field testing on plants burning primarily low-rank coals or blends (with some units burning bituminous coal) and equipped with a variety of APCD configurations.

Most of the 14 projects fall under two general categories of mercury control – sorbent injection or oxidation enhancements. Sorbent injection generically describes conventional ACI, chemically-treated ACI, or the injection of non-carbon sorbents into the flue gas for mercury control. Mercury oxidation enhancements are intended to improve the mercury capture efficiency of conventional ACI or downstream APCD by converting elemental mercury to a more reactive oxidized state. For instance, coal or flue gas additives are being investigated both alone, and in conjunction with conventional ACI. Additional mercury control technologies are being tested to enhance mercury capture at coal-fired units equipped with wet FGD systems. These FGD-related technologies include coal and flue gas chemical additives and fixed-bed catalysts to increase levels of oxidized mercury in the combustion flue gas, and wet FGD chemical additives to promote mercury capture and prevent re-emission of elemental mercury from the FGD absorber vessel.

Note that DOE/NETL also selected 12 new projects in 2006 to conduct longer-term mercury control technology field tests at utilities and in the laboratory under a Phase III mercury control solicitation. Building on advances from the Phase I and II mercury projects, Phase III, which is scheduled for completion in 2009, has four topic areas ranging from bench-scale testing of novel concepts to full-scale, multi-month field tests of 90% mercury capture via ACI.

[h] The seven Phase II-2 mercury control technologies are: TOXECON™, TOXECON™ II, high-temperature mercury sorbents, brominated PAC injection, chemically-treated PAC injection via the Mer-Cure™ process, wet FGD chemical additives, and an integrated approach to mercury control that includes combustion modifications.

Table 6 -- DOE/NETL's Phase II-1 Field Testing Projects

Project Title	Lead Company	Test Location	Coal Rank	APCD Configuration
Evaluation of Sorbent Injection for Mercury Control	ADA-ES	Sunflower Electric's Holcomb Unit 1	PRB	SDA/FF
		AmerenUE's Meramec Unit 2	PRB	CS-ESP (320 SCA)
		Missouri Basin Power Project's Laramie River Unit 3	PRB	SDA & CS-ESP (599 SCA)
		DTE Energy's Monroe Unit 4	PRB/Bit. Blend	SCR & CS-ESP (258 SCA)
		American Electric Power's Conesville Unit 6	High-Sulfur Bituminous	CS-ESP (301 SCA) & Wet FGD
		AmerenUE's Labadie Unit 2	PRB	CS-ESP (279 SCA)
Sorbent Injection for Small ESP Mercury Control	URS Group	Southern Company's Plant Yates Unit 1	Low-Sulfur Bituminous	CS-ESP (173 SCA) & Wet FGD
		Southern Company's Plant Yates Unit 2	Low-Sulfur Bituminous	CS-ESP (144 SCA)
		Reliant Energy's Shawville Unit 3	Mid-Sulfur Bituminous	Two CS-ESPs (82 & 230 SCA)
Enhancing Carbon Reactivity in Mercury Control in Lignite-Fired Systems	UNDEERC	Basin Electric's Leland Olds Unit 1	ND Lignite	CS-ESP (320 SCA)
		Great River Energy's Stanton Unit 10	ND Lignite	SDA/FF
		Basin Electric's Antelope Valley Unit 1	ND Lignite	SDA/FF
		Great River Energy's Stanton Unit 1	PRB	CS-ESP (470 SCA)
		Montana-Dakota Utilities Co. Lewis & Clark Station	ND Lignite	Mechanical Collector & Wet Venturi Scrubber
Advanced Utility Mercury Sorbent Field-Testing Program	Sorbent Technologies	DTE Energy's St. Clair Unit 1	PRB/Bit. Blend	CS-ESP (SCA 467)
		Duke Energy's Buck Unit 6	Low-Sulfur Bituminous	HS-ESP (240 SCA)
Demonstration of Amended Silicates for Mercury Control	Amended Silicates	Cinergy's Miami Fort Unit 6	Mid-Sulfur Bituminous	CS-ESP (353 SCA)
Pilot Testing of Mercury Oxidation Catalysts for Upstream of Wet FGD Systems	URS Group	TXU's Monticello Unit 3	TX Lignite/PRB blend	CS-ESP (452 SCA) & Wet FGD
		Southern Company's Plant Yates Unit 1	Low-Sulfur Bituminous	CS-ESP (173 SCA) & Wet FGD
Evaluation of MerCAP™ for Power Plant Mercury Control	URS Group	Great River Energy's Stanton Unit 10	ND Lignite	SDA/FF
		Southern Company's Plant Yates Unit 1	Low-Sulfur Bituminous	CS-ESP (173 SCA) & Wet FGD
Mercury Oxidation Upstream of an ESP and Wet FGD	UNDEERC	Minnkota Power's Milton R. Young Unit 2	ND Lignite	CS-ESP (375 SCA) & Wet FGD
		TXU's Monticello Unit 3	TX Lignite/PRB blend	CS-ESP (452 SCA) & Wet FGD

Table 7 -- DOE/NETL's Phase II-2 Field Testing Projects

Project Title	Lead Company	Test Location	Coal Rank	APCD Configuration
Field Testing of Activated Carbon Injection Options for Mercury Control	UNDEERC	TXU's Big Brown Unit 2	TX Lignite/PRB Blend	CS-ESP (162 SCA) & COHPAC® FF
Field Demonstration of Enhanced Sorbent Injection for Mercury Control	ALSTOM-PPL	PacifiCorp's Dave Johnston Unit 3	PRB	CS-ESP (600 SCA)
		Basin Electric's Leland Olds Unit 1	ND Lignite	CS-ESP (320 SCA)
		Reliant Energy's Portland Unit 1	Mid-Sulfur Bituminous	CS-ESP (284 SCA)
Low Cost Options for Moderate Levels of Mercury Control	ADA-ES	Entergy's Independence Unit 1	PRB	CS-ESP (542 SCA)
		MidAmerican's Louisa Unit 1	PRB	HS-ESP (459 SCA)
		MidAmerican's Council Bluffs Unit 2	PRB	HS-ESP (224 SCA)
Brominated Sorbents for Small Cold-Side ESPs, Hot-Side ESPs, and Fly Ash use in Concrete	Sorbent Technologies	Progress Energy's Lee Unit 1	Low-Sulfur Bituminous	CS-ESP (300 SCA)
		Midwestern Generation's Crawford Unit 7	PRB	CS-ESP (112 SCA)
		Midwestern Generation's Will County Unit 3	PRB	HS-ESP (173 SCA)
Field Testing of a Wet FGD Additive for Enhanced Mercury Control	URS Group	TXU's Monticello Unit 3	TX Lignite/PRB blend	CS-ESP (452 SCA) & Wet FGD
		Southern Company's Plant Yates Unit 1	Low-Sulfur Bituminous	CS-ESP (173 SCA) & Wet FGD
		Indianapolis Power & Light's Petersburg Unit 2	High-Sulfur Bituminous	CS-ESP (430 SCA) & Wet FGD
Demonstration of Integrated Approach to Mercury Control	GE-EERC	Progress Energy's Lee Unit 3	Low-Sulfur Bituminous	CS-ESP (300 SCA)

The following is a brief summary of results for the 12 coal-fired units included in this economic analysis, while a complete description of these Phase II field testing sites is provided in Appendix B of this report.[i] Note that data presented throughout this report is grouped by coal rank (i.e., bituminous, PRB, and ND lignite) to facilitate meaningful economic comparisons. However, two units included in this study burn coal blends: St. Clair Station Unit 1, and Monroe Station Unit 4. St. Clair, which typically burns an 85% PRB and 15% bituminous coal blend, is grouped with the PRB units based on parametric testing results where mercury removal via conventional DARCO® Hg injection was limited to about 70%, while greater than 90% mercury removal was achieved with brominated B-PAC™ injection at 3 lb/MMacf.[13] A similar trend was observed during Phase II testing at the 100% PRB-fired Meramec Station Unit 2.[14] Meanwhile, the similar results obtained during parametric tests with conventional DARCO® Hg and brominated DARCO® Hg-LH at Monroe, which normally fires a 60% PRB and 40% low- to

[i] A similar analysis will be conducted in the future for the remaining test sites as results become available.

medium-sulfur bituminous coal blend, led to this unit being grouped with the bituminous units.[15] Moreover, the coal blend burned at Monroe has a chlorine content of about 550 ppm (on a wet basis), which is more typical of a bituminous coal.

In addition to a brief description of full-scale field testing results, a parametric performance curve is provided for each of these Phase II sites. Short-term parametric tests are conducted at each of the Phase II field testing sites to: (1) gain a better understanding of the plant-specific factors that influence mercury capture; (2) determine the best sorbent for long-term testing; and (3) establish the optimal operating conditions for the long-term continuous injection test. Therefore, a series of performance curves that graphically display the relationship between ACI concentration and mercury removal are generated during parametric testing. The parametric performance curves displayed in Figures 2-4 serve as the foundation for the 12 economic analyses included in this report. The selection of these particular curves was dictated by the long-term continuous injection trial performed at each site. For example, the performance of B-PAC™ during parametric tests at Lee Station Unit 1 is displayed in Figure 2, because B-PAC™ was selected for evaluation during the 30-day long-term test at this unit.

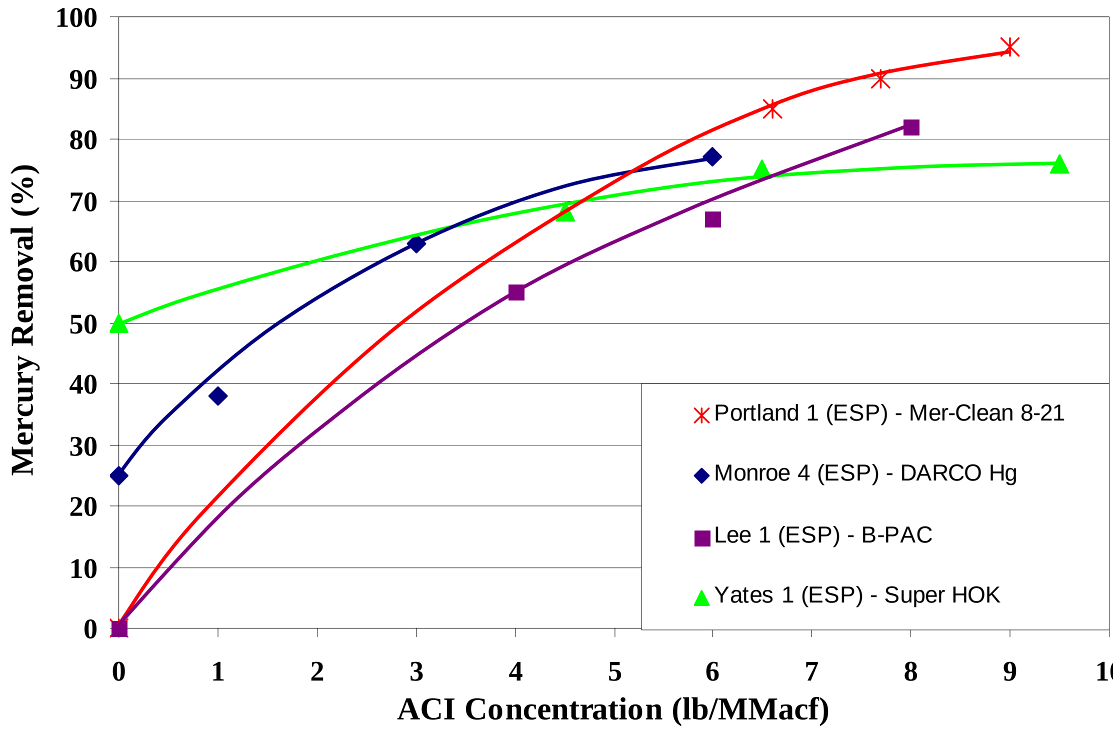
Bituminous Coal-Fired Units

Three Phase II sites included in this analysis burned eastern bituminous coal during full-scale field testing. In addition, as discussed above, the Monroe Station, which typically fires a 60% PRB and 40% low- to medium-sulfur bituminous coal blend, is considered a bituminous-fired unit for the purpose of this analysis.

- **Plant Yates Unit 1** - URS Group, Inc. (URS) completed a full-scale mercury control technology field test at the 100 megawatt (MW) Plant Yates Unit 1 located in Newnan, Georgia.[16] The unit fires low-sulfur eastern bituminous coal and is equipped with a CS-ESP (173 SCA) and a downstream Jet Bubbling Reactor (JBR) wet FGD. Mercury control cost estimates for Yates are based on the performance of conventional Super HOK injection during a 30-day long-term field test. As shown in Figure 2, approximately 50% baseline mercury capture was observed prior to the December 2004 long-term field test. Total mercury removal averaged about 75% with a Super HOK injection concentration ranging from 6.5 to 9.5 lb/MMacf.

- **Monroe Station Unit 4 –** ADA-ES evaluated multiple mercury control technologies during full-scale field testing at the 785 MW Monroe Station Unit 4 located in Monroe, Michigan. This unit burns a 60% PRB and 40% low- to medium-sulfur bituminous coal blend and is equipped with an SCR that operates during the ozone season (May 1 – September 30) and a downstream CS-ESP, which is assisted by a flue gas conditioning (FGC) system that injects sulfur trioxide (SO_3) upstream of the air preheater to modify fly ash resistivity and improve particulate collection. Cost estimates for mercury control at Monroe are based on the performance of conventional DARCO® Hg injection with the SCR and SO_3 FGC system in-service. As shown in Figure 2, baseline mercury capture was about 25% prior to the parametric testing campaign, and 77% total mercury removal was achieved with a DARCO® Hg injection concentration of 6 lb/MMacf. Similar performance was observed during the injection of brominated DARCO® Hg-LH, and conventional DARCO® Hg was selected for long-term testing as a lower-cost alternative. During the 30-day long-term field test completed in July 2005, 87% average total mercury removal was observed with an average DARCO® Hg injection concentration of 5.9 lb/MMacf.

Figure 2 -- ACI Performance Data for Phase II Units Firing Bituminous Coal[j]



- **Lee Station Unit 1** – Sorbent Technologies Corporation completed a full-scale field test of brominated B-PAC™ injection at the 79 MW Lee Station Unit 1 located in Goldsboro, North Carolina.[17] This low-sulfur eastern bituminous coal-fired unit is equipped with a CS-ESP that is aided by an SO_3 FGC system located upstream of the air preheater. Mercury control cost estimates for Lee are based on the performance of cold-side B-PAC™ injection with the SO_3 FGC system idled. As shown in Figure 2, greater than 80% incremental mercury capture was achieved during parametric testing with a B-PAC™ injection concentration of 8 lb/MMacf. Note that the parametric data presented in Figure 2 for Lee has been adjusted to account for baseline mercury capture and represents the level of mercury control that is directly attributable to brominated B-PAC™ injection. During the 30-day long-term field test completed in April 2006, 85% average total mercury removal was observed with an average B-PAC™ injection concentration of 8 lb/MMacf. Baseline mercury removal was approximately 20% prior to long-term testing.

- **Portland Station Unit 1** – Alstom Power, Inc., U.S. Power Plant Laboratories (ALSTOM-PPL) conducted full-scale field testing at the 172 MW Portland

[j] The figure displays total mercury removal for Monroe and Yates, while the data presented for Portland and Lee represents mercury removal due to ACI since the parametric data has been adjusted to account for baseline mercury removal by ALSTOM-PPL and Sorbent Technologies, respectively.

Station Unit 1, located in Portland, Pennsylvania, to evaluate the mercury capture efficiency of several chemically-treated Mer-Clean™ sorbents in the Mer-Cure™ system.[k] This medium-sulfur (~2%) eastern bituminous coal-fired unit is equipped with a CS-ESP for particulate control.[18,19] Cost estimates for mercury control at Portland are based on the performance of chemically-treated Mer-Clean™ 8-21 injection during parametric and long-term field tests. As shown in Figure 2, about 90% incremental mercury capture was achieved during parametric testing with a Mer-Clean™ 8-21 injection concentration of 7.7 lb/MMacf. Note that the parametric data presented in Figure 2 for Portland has been adjusted to account for baseline mercury capture and represents the level of mercury control that is directly attributable to chemically-treated Mer-Clean™ 8-21 injection. During the long-term field test completed in June 2006, approximately 96% total mercury removal was achieved with an average Mer-Clean™ 8-21 injection concentration of 8.5 lb/MMacf. Baseline mercury removal was approximately 30% prior to long-term testing.

PRB Subbituminous Coal-Fired Units

Four Phase II sites included in this analysis burned PRB subbituminous coal during full-scale field testing. In addition, as discussed above, the St. Clair Station, which typically fires an 85% PRB and 15% low-sulfur bituminous coal blend, is considered a PRB-fired unit for the purpose of this analysis.

- **Holcomb Station Unit 1** - ADA-ES evaluated several mercury control technologies during full-scale field testing at the 360 MW Holcomb Station Unit 1 located in Holcomb, Kansas.[20] This PRB-fired unit is equipped with an SDA/FF configuration. Mercury control cost estimates for Holcomb are based on the performance of brominated DARCO® Hg-LH injection during parametric and long-term field tests. As shown in Figure 3, baseline mercury capture was about 37% prior to the parametric testing campaign, and approximately 95% total mercury removal was achieved with a DARCO® Hg-LH injection concentration of 4.3 lb/MMacf. During the 30-day long-term field test completed in August 2004, 93% average total mercury removal was achieved with an average DARCO® Hg-LH injection concentration of 1.2 lb/MMacf.

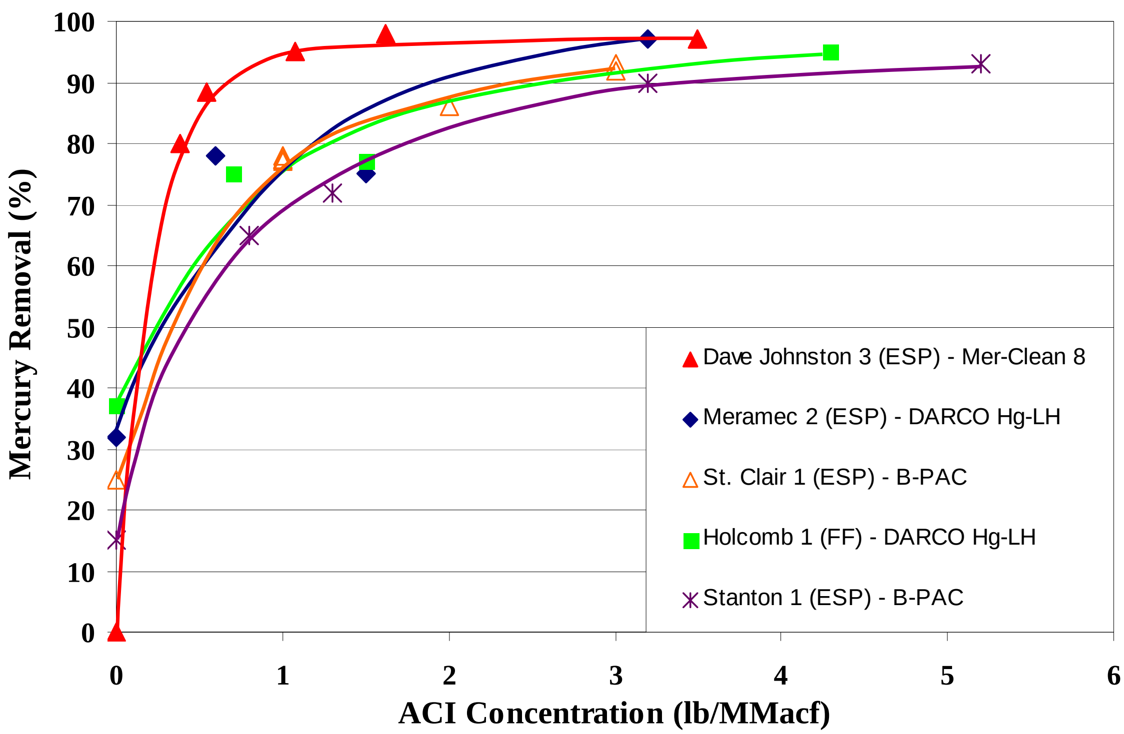
- **St. Clair Station Unit 1 –** Sorbent Technologies Corporation conducted full-scale field testing of brominated B-PAC™ injection at the 145 MW St. Clair Station Unit 1 located in East China, Michigan. This blended coal-fired unit is equipped with a CS-ESP for particulate control. Cost estimates for mercury control at St. Clair are based on the performance of brominated B-PAC™ injection during parametric and long-term field tests. As shown in Figure 3, baseline mercury capture was about 25% prior to the parametric testing campaign, and approximately 93% total mercury removal was achieved with a B-PAC™ injection concentration of 3 lb/MMacf. During the 30-day long-term field test

[k] The Mer-Cure™ process is unique in that chemically-treated Mer-Clean™ sorbent injection takes place in the high-temperature region upstream of the air preheater, which extends the residence time available for in-flight mercury capture prior to entering the particulate control device (ESP or FF). In addition, the Mer-Cure™ process includes a proprietary "processor" that yields more uniform sorbent dispersion by minimizing sorbent agglomeration in the injection lances.

completed in October 2004, 94% average total mercury removal was achieved with an average B-PAC™ injection concentration of 3 lb/MMacf.

- **Meramec Station Unit 2** – ADA-ES evaluated multiple mercury control technologies during full-scale field testing at the 140 MW Meramec Station Unit 2 located in St. Louis, Missouri. This PRB-fired unit is equipped with a CS-ESP. Mercury control cost estimates for Meramec are based on the performance of brominated DARCO® Hg-LH injection during parametric and long-term field tests. As shown in Figure 3, baseline mercury capture was about 32% prior to the parametric testing campaign, and approximately 97% total mercury removal was achieved with a DARCO® Hg-LH injection concentration of 3.2 lb/MMacf. During the 30-day long-term field test completed in November 2004, 93% average total mercury removal was achieved with an average DARCO® Hg-LH injection concentration of 3.3 lb/MMacf.

Figure 3 – ACI Performance Data for Phase II Units Firing PRB Coal[1]



- **Dave Johnston Unit 3** – ALSTOM-PPL evaluated the mercury capture efficiency of several chemically-treated Mer-Clean™ sorbents in the Mer-Cure™ system during full-scale field testing at the 240 MW Dave Johnston Unit 3 located in Glenrock, Wyoming.[21,22] This PRB-fired unit is equipped with a CS-ESP. Cost estimates for mercury control at Dave Johnston are based on the performance of chemically-treated Mer-Clean™ 8 injection during parametric and long-term field tests. As shown in Figure 3, 95% incremental mercury capture was achieved

[1] The figure displays total mercury removal for Meramec, St. Clair, Holcomb, and Stanton Unit 1. The data presented for Dave Johnston represents mercury removal due to ACI since the parametric data has been adjusted to account for baseline mercury removal by ALSTOM-PPL.

during parametric testing with a Mer-Clean™ 8 injection concentration of about 1 lb/MMacf. Note that the parametric data presented in Figure 3 for Dave Johnston has been adjusted to account for baseline mercury capture and represents the level of mercury control that is directly attributable to chemically-treated Mer-Clean™ 8 injection. During the long-term field test completed in September 2005, approximately 92% total mercury removal was achieved with an average Mer-Clean™ 8 injection concentration of 0.63 lb/MMacf. Baseline mercury removal was approximately 12% prior to long-term testing.

- **Stanton Station Unit 1 –** URS evaluated the mercury capture efficiency of several sorbents during full-scale field testing at the 150 MW Stanton Station Unit 1 located in Stanton, North Dakota.[17,23] This PRB-fired unit is equipped with a CS-ESP. Mercury control cost estimates for Stanton Unit 1 are based on the performance of brominated B-PAC™ injection during parametric and long-term field tests. As shown in Figure 3, baseline mercury capture was about 15% prior to the parametric testing campaign, and approximately 90% total mercury removal was achieved with a B-PAC™ injection concentration of 3.2 lb/MMacf. During the 30-day long-term field test completed in October 2005, 85% average total mercury removal was achieved with an average B-PAC™ injection concentration of 1.7 lb/MMacf.

ND Lignite Coal-Fired Units

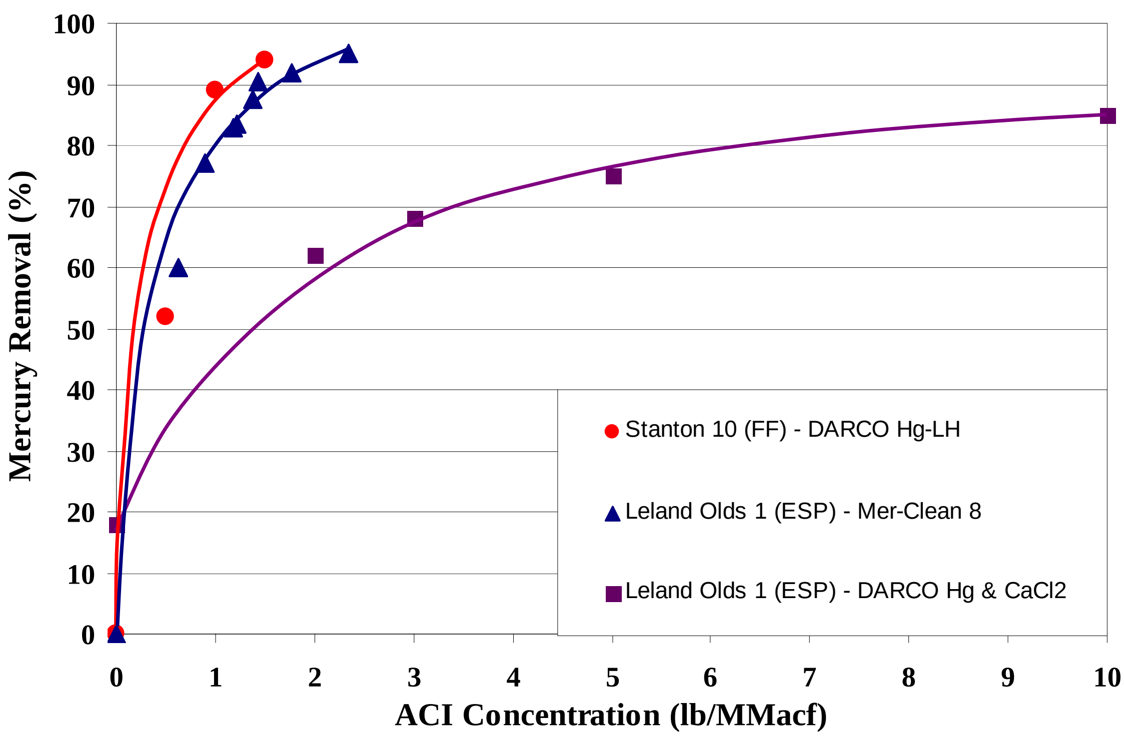
Two Phase II sites included in this analysis burned ND lignite coal during full-scale field testing. However, this report includes two separate economic analyses for mercury control at Leland Olds Station Unit 1 since field testing was conducted at this site under two different Phase II projects.

- **Leland Olds Unit 1** - The University of North Dakota Energy & Environmental Research Center (UNDEERC) completed a full-scale mercury control technology field test at the 220 MW Leland Olds Station Unit 1 located in Stanton, North Dakota.[24,25] This ND lignite-fired unit is equipped with a CS-ESP for particulate control. Mercury control cost estimates for Leland Olds are based on the performance of conventional DARCO® Hg injection, coupled with the addition of SEA1 ($CaCl_2$) to the coal prior to combustion, during parametric and long-term field tests. As shown in Figure 4, baseline mercury capture was about 18% prior to the parametric testing campaign, and approximately 85% total mercury removal was achieved with a DARCO® Hg injection concentration of 10 lb/MMacf when $CaCl_2$ was added to the coal. During the 30-day long-term field test completed in May 2004, 58% average total mercury removal was achieved with average DARCO® Hg and $CaCl_2$ injection concentrations of 2.7 and 2.9 lb/MMacf, respectively.

- **Stanton Station Unit 10** - UNDEERC evaluated the mercury capture efficiency of several conventional and chemically-treated sorbents during full-scale field testing at the 60 MW Stanton Station Unit 10 located in Stanton, North Dakota.[26] This ND lignite-fired unit is equipped with an SDA/FF configuration. Cost estimates for mercury control at Stanton Unit 10 are based on the performance of brominated DARCO® Hg-LH injection during parametric and long-term field tests. As shown in Figure 4, no baseline mercury capture was observed prior to the parametric testing campaign, and approximately 90% total mercury removal was achieved with a DARCO® Hg-LH injection concentration of 1 lb/MMacf. During the 30-day long-term field test completed in July 2004, 60% average total mercury removal was achieved with average DARCO® Hg-LH injection concentration of 0.7 lb/MMacf.

- **Leland Olds Unit 1** - ALSTOM-PPL evaluated the mercury capture efficiency of several chemically-treated Mer-Clean™ sorbents in the Mer-Cure™ system during full-scale field testing at the 220 MW Leland Olds Station Unit 1.[27] Mercury control cost estimates for Leland Olds are based on the performance of chemically-treated Mer-Clean™ 8 injection during parametric and long-term field tests. As shown in Figure 4, about 95% incremental mercury capture was achieved during parametric testing with a Mer-Clean™ 8 injection concentration of about 2.35 lb/MMacf. Note that the parametric data presented in Figure 4 for Leland Olds has been adjusted to account for baseline mercury capture and represents the level of mercury control that is directly attributable to chemically-treated Mer-Clean™ 8 injection. During the long-term field test completed in November 2005, approximately 90% total mercury removal was achieved with an average Mer-Clean™ 8 injection concentration of 1.4 lb/MMacf. To be consistent with the other Leland Olds dataset, 18% baseline mercury removal was used to complete this analysis.

Figure 4 – ACI Performance Data for Phase II Units Firing ND Lignite Coal[m]



[m] The figure displays total mercury removal for Stanton Unit 10 and Leland Olds (DARCO® Hg & $CaCl_2$). The Mer-Clean™ 8 data presented for Leland Olds represents mercury removal due to ACI since the parametric data has been adjusted to account for baseline mercury removal by ALSTOM-PPL.

III. ECONOMIC FRAMEWORK

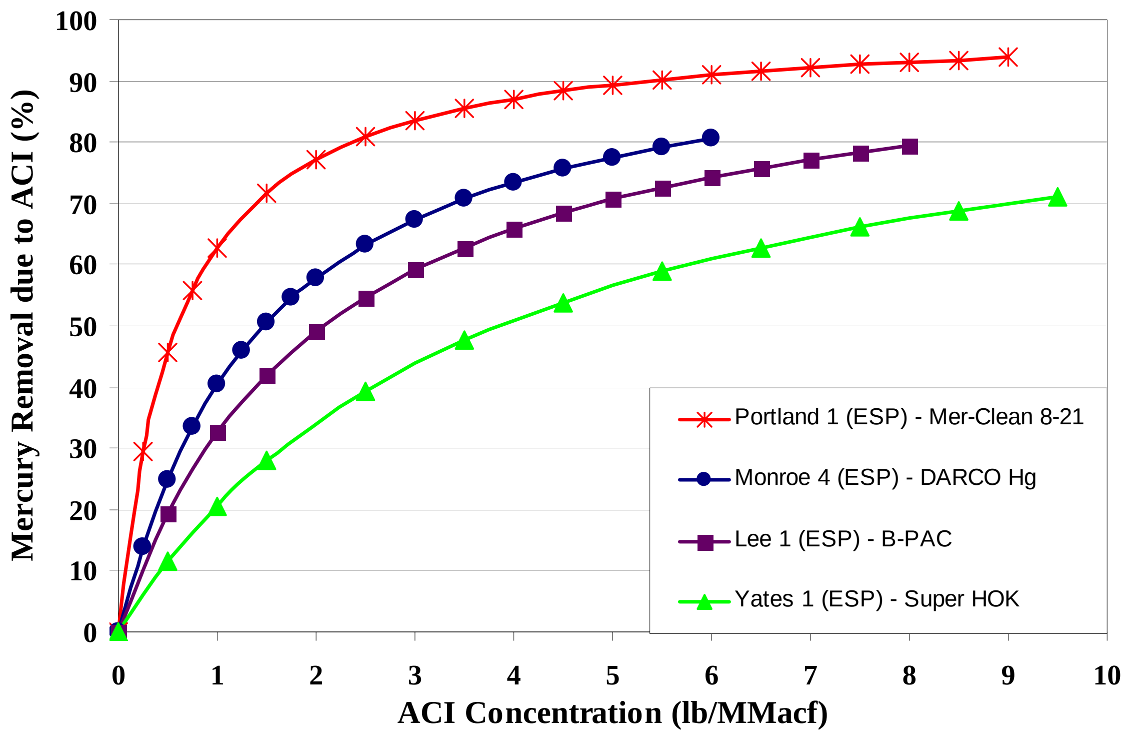
This report provides "study-level" cost estimates for mercury control via ACI based on preliminary results obtained from DOE/NETL's Phase II field testing of advanced mercury control technologies. The study was carried out to provide DOE/NETL a gauge in measuring its success in achieving the target of reducing baseline mercury control costs by 25 to 50%. The economic analyses were conducted on a plant-specific basis meaning that the economics are dependent on the actual power plant operating conditions and coal properties observed during full-scale field testing at these Phase II sites. In particular, the cost estimates provided in this report are highly dependent on the: (1) ACI concentration required to achieve a given level of mercury control during both parametric and long-term testing; (2) delivered PAC cost; (3) coal mercury content (lb/TBtu); and (4) level of baseline mercury removal observed prior to the parametric tests involving the PAC that was ultimately selected for evaluation during long-term testing. Note the Phase II long-term tests are conducted under optimal conditions established during the parametric testing campaign.

The economic analyses were conducted in a manner that yields the cost required to achieve low (50%), mid (70%), and high (80-90%) levels of mercury control "above and beyond" the plant-specific baseline mercury removal. In other words, the levels of mercury control discussed in this report are directly attributable to ACI. This approach is complicated by the variability of baseline mercury capture caused by changes in coal composition and boiler performance that can impact the quantity of unburned carbon present in the fly ash. In addition, field testing has shown that residual PAC remaining in the ductwork from previous injection trials may contribute to an increase in baseline mercury capture over the course of the parametric testing campaign. With that in mind, a conscious effort was made to identify the baseline mercury capture observed prior to the parametric tests involving the PAC that was selected for evaluation during long-term testing.

To determine the percentage of total mercury removal that is attributable to ACI (i.e., ACI mercury removal), the parametric performance curves and the average mercury removal observed during the long-term continuous injection test were adjusted. The data adjustment methodology is intended to account for the baseline mercury removal observed prior to parametric testing. The baseline adjusted parametric performance curves were then scaled to conform to the average mercury removal observed during the long-term test. The latter adjustment was performed, because the results obtained from long-term testing are thought to be more representative of the mercury removal efficiency of ACI than the short-term parametric results. The resultant ACI datasets were used to develop the final adjusted algorithms that express the percent mercury removal attributable to ACI as a function of ACI concentration. These algorithms are represented by the non-linear regression curves displayed in Figures 5-7. A complete discussion of the data adjustment methodology, with sample calculations, is provided in Appendix C of this report.

The adjusted regression curves for the three bituminous units and Monroe are shown in Figure 5. This figure illustrates the range of ACI mercury removal levels that were analyzed for each Phase II site. For instance, a cost estimate for 90% ACI mercury removal via chemically-treated Mer-Clean™ 8-21 injection Portland is included in this report, while 80% ACI mercury removal is the maximum level of control that is analyzed for Monroe and Lee. For Yates, cost estimates for 50 and 70% ACI mercury removal via conventional Super HOK injection were calculated.

Figure 5 -- Adjusted Non-Linear Regression Curves for Phase II Units Firing Bituminous Coal



As shown in Figure 6, cost estimates for 90% ACI mercury removal via chemically-treated ACI were developed for each of the four PRB units and St. Clair. In fact, each of these adjusted regression curves cross 70% ACI mercury removal at a chemically-treated ACI rate of less than 1 lb/MMacf. The curves displayed for Dave Johnston and Holcomb are noteworthy as 90% ACI mercury removal is achieved at an injection rate of about 1 lb/MMacf or less.

Two adjusted regression curves are presented in Figure 7 for Leland Olds, along with a curve for the ND lignite-fired Stanton Unit 10. For Leland Olds, greater than 90% ACI mercury removal was attained with chemically-treated Mer-Clean™ 8 injection, while cost estimates for conventional ACI, coupled with SEA coal treatment, are limited to 80% ACI mercury removal. Meanwhile, the curve displayed for Stanton 10 was extrapolated slightly to calculate a cost estimate for 80% ACI mercury removal via brominated ACI.

Figure 6 - Adjusted Non-Linear Regression Curves for Phase II Units Firing PRB Coal

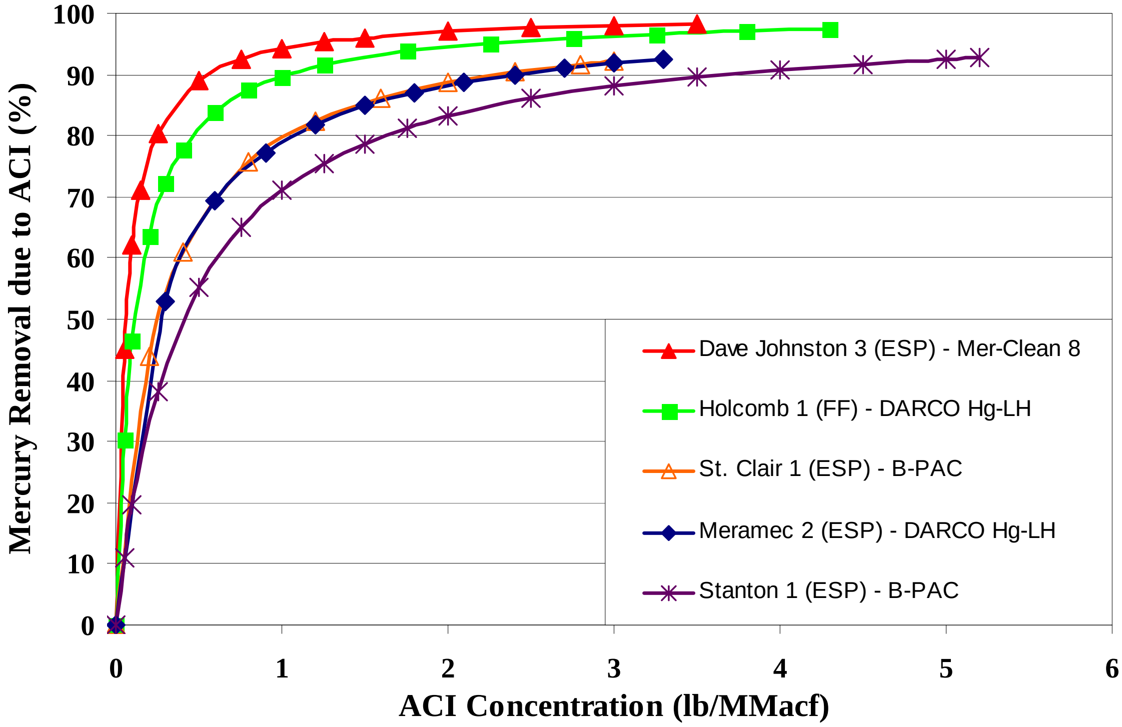
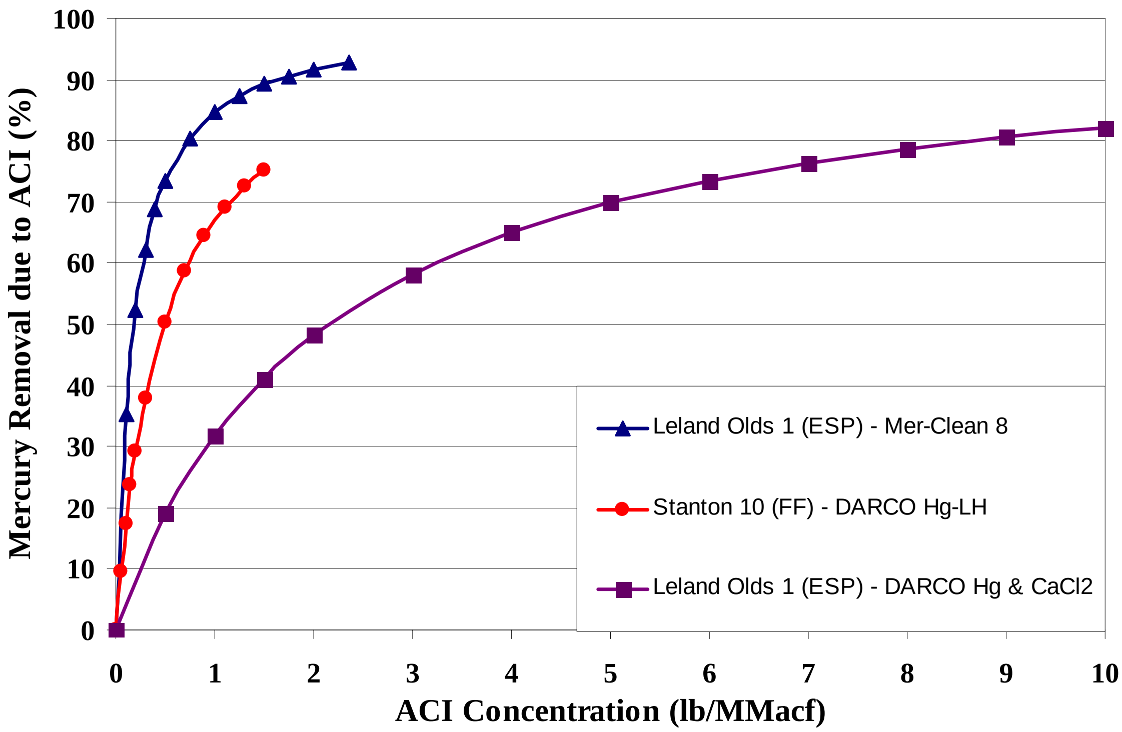


Figure 7 - Adjusted Non-Linear Regression Curves for Phase II Units Firing ND Lignite Coal



The importance of developing accurate non-linear algorithms cannot be overstated. The algorithms are used to calculate the quantity of PAC required to achieve a given level of ACI mercury control. In some instances, the costs associated with PAC consumption account for approximately 90% of the total cost of mercury control. Therefore, the algorithms represent a critical element of this economic analysis. Additional components of the ACI cost estimates presented in this report are discussed below.

Capital Costs

As part of the DOE/NETL Phase II field testing program, ADA-ES recently completed economic evaluations of mercury control via ACI based on the results obtained during full-scale field testing at the Holcomb, Meramec and Monroe Stations.[14,15,20] These estimates were used to approximate the capital cost required to retrofit similar ACI systems at some of the other Phase II field testing sites included in this economic analysis. For the Mer-Cure™ system, which was demonstrated at three Phase II sites, ALSTOM-PPL provided a capital cost estimate expressed as a function of unit capacity ($/kW).[n]

The ACI capital cost estimates include both direct and indirect cost components. The total direct cost (TDC) for the ACI system is calculated as the sum of the following cost components: (1) uninstalled equipment cost; (2) materials and labor associated with site integration; (3) applicable taxes; and (4) installation costs that can vary significantly depending on plant-specific retrofit issues. In addition, an estimated cost of $125,000 is included for the installation of an SEA storage and injection system at Leland Olds.

The indirect costs were estimated as percentages of the TDC using the EPRI Technical Assessment Guide (TAG™) methodology. For instance, 10% of the TDC was set aside for general facility and engineering fees. The project contingency was calculated as 15% of the TDC, while 5% was used for process contingency since the technology is relatively simple. Note that no adjustments were made for interest during construction since it is assumed that the ACI system can be installed in a few months. The total capital requirement (TCR) for the mercury sorbent storage and injection system is calculated with the inclusion of indirect costs and contingencies. However, the capital cost required to install and calibrate a mercury monitoring system was excluded from this analysis since utilities will incur these costs regardless of their mercury control strategy.

The TCR for each of the Phase II field testing sites included in this economic analysis is presented in Tables 9-17. Upon inspection of these tables, the reader should note that the overall TCR is independent of the desired level of mercury control and only slightly dependent on unit capacity. Meanwhile, the TCR values expressed as a function of unit capacity range from $3.63/kW for the 360 MW Holcomb Station Unit 1 to $21.10/kW for the 60 MW Stanton Station Unit 10.

Annual Operating and Maintenance (O&M) Costs

Annual O&M costs were calculated using an assumed capacity factor of 80%. These annual expenditures consist of several components, including: (1) PAC consumption; (2)

[n] A more-detailed description of these capital cost estimates is provided in Appendix D of this report.

SEA consumption is included for Leland Olds Unit 1; (3) other costs[o]; and (4) the potential cost of byproduct management and non-hazardous disposal. An average incremental operating labor requirement of four hours per day was estimated to cover the incremental labor required to operate and monitor the PAC storage and injection system. The annual maintenance costs are based on 5% of the uninstalled equipment cost. The contribution of each component as well as the total first-year annual O&M cost is presented in Tables 9-17.

A general description of the mercury sorbents included in this analysis is provided below. The delivered prices ($/lb) shown in Table 8 include $0.10/lb for transportation expenses. An estimated delivered cost of $0.20/lb was used for the aqueous $CaCl_2$ solution added to the coal during testing at Leland Olds Unit 1. This price also includes a $0.10/lb charge for transportation expenses.

Table 8 -- Description of Powdered Activated Carbons

PAC	Manufacturer	Description	Delivered Price ($/lb)
B-PAC™	Sorbent Technologies	Brominated	$0.95
DARCO® Hg	NORIT Americas	Conventional (untreated)	$0.54
DARCO® Hg-LH	NORIT Americas	Brominated	$0.95
Mer-Clean™ 8	ALSTOM-PPL	Chemically-treated	$1.35
Mer-Clean™ 8-21	ALSTOM-PPL	Chemically-treated	$1.35
Super HOK	RWE Rhinebraun	Conventional	$0.39

The costs associated with the management and non-hazardous disposal of the captured PAC 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. For this analysis, the PAC disposal costs were calculated using an estimated value of $17/ton.

PAC injection upstream of an existing ESP may adversely impact the ability to market fly ash for beneficial use applications. Because an important market for fly ash is the manufacture of concrete, any additional carbon content may render it unsuitable for sale. For instance, DOE/NETL Phase I field testing at Pleasant Prairie rendered the ash unsuitable for use in concrete during the entire test period. ACI concentrations used for this analysis result in an increase in carbon-in-ash concentration ranging from approximately 0.02 wt% carbon to 2.84 wt% carbon.[p] Along with the potential loss of revenue from the sale of the ash, the affected unit would need to pay for disposal of fly ash that would have otherwise been sold. For this analysis, the total byproduct impacts are based on an estimated value of $35/ton, which includes $18/ton for lost revenue from fly ash sales and $17/ton for non-hazardous fly ash disposal.

However, the byproduct impacts associated with ACI may not be as severe for units equipped with the SDA/FF configuration (e.g., Holcomb Station Unit 1 and Stanton Station Unit 10) since the majority of recycled SDA byproducts are used for low-value

[o] Other related O&M costs include electric power, O&M labor, and spare parts. The assumptions used to quantify these "other" annual O&M costs are included in Appendix A of this report.

[p] The increase in carbon-in-ash concentration is calculated using the following equation:
wt% carbon = [ACI (lb/hr) / (ACI (lb/hr) + Fly ash generation (lb/hr))] x 100%. A complete discussion pertaining to the implications of ACI on fly ash sales is included in the Discussion section of this report.

mining applications.[28] Consequently, the SDA byproduct (i.e., SDA ash and solid calcium sulfite) impacts only account for the added cost of $17/ton for non-hazardous SDA byproduct disposal (i.e., no lost revenue from sales). For this analysis, the quantity of calcium sulfite generated was calculated using the coal sulfur content (Appendix A), assuming 90% SO_2 capture across the SDA/FF configuration.

Incremental Cost of Mercury Control

For this analysis, the 20-year levelized costs for the incremental increase in cost of electricity (COE), expressed in mills per kilowatt-hour (mills/kWh), and the incremental cost of mercury control ($/lb Hg removed) are reported on a current dollar basis both with and without the inclusion of added costs associated with byproduct management and non-hazardous disposal. The current dollar cost estimates represent the dollar value of goods or services in terms of prices current at the time the goods or services are purchased. In other words, the 20-year levelized costs developed during this economic analysis include the effects of inflation. Additional economic assumptions are documented in Appendix A of this report.

The incremental cost of mercury reduction, i.e. the cost (in $/lb Hg removed) to achieve a specific reduction can vary significantly with various assumptions including the level of baseline mercury capture, the coal mercury content (lb/TBtu), and the ash content of the coal when byproduct impacts are considered. For example, the incremental cost of mercury control will increase when: (1) baseline mercury capture is high; or (2) the coal mercury content is low, because a smaller quantity of mercury is removed from the flue gas for a given level of control. For this analysis, the incremental cost of mercury control was calculated using the quantity of mercury removed by ACI. This was accomplished by: (1) converting the coal mercury content to a flue gas mercury flow rate (lb/hr); (2) reducing the flue gas mercury flow rate by a percentage consistent with that unit's baseline mercury removal to calculate the quantity of mercury removed under baseline conditions; and (3) taking a percentage of the mercury remaining in the system to determine the quantity of mercury removed that is directly attributable to ACI for a given level of control (e.g., 0.7 for 70% mercury control).

Analysis presented in the earlier DOE/NETL economic study[12] demonstrated 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 costs of mercury removal.[q] 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).

[q] For 70% total mercury removal via conventional ACI at a representative 500 MW bituminous-fired unit, with coal properties and existing baseline mercury capture based on averages derived from EPA's ICR data, the incremental cost of mercury control ranges from approximately $25,000/lb Hg removed (15 lb/TBtu) to $125,000/lb Hg removed (3 lb/TBtu), when byproduct impacts are excluded.

Table 9 - Cost Estimate for 50% Mercury Removal at Bituminous Units

50% ACI Mercury Removal				
Plant	**Plant Yates Unit 1**	**Monroe Station Unit 4**	**Lee Station Unit 1**	**Portland Station Unit 1**
Capacity, MW	100	785	79	172
Fuel	Low-Sulfur Bituminous	60:40 PRB/Bit. Blend	Low-Sulfur Bituminous	Medium-Sulfur Bituminous
Coal Hg Content, lb/TBtu	5.92	5.59	3.35	8.23
Flue Gas Flow Rate, acfm	480,000	3,600,000	320,000	520,621
Unit APCD	CS-ESP & Wet FGD	SCR & CS-ESP (SO_3 FGC)	CS-ESP	CS-ESP
PAC / SEA	Super HOK	DARCO® Hg	B-PAC™	Mer-Clean™ 8-21
ACI Rate, lb/MMacf	3.85	1.46	2.07	0.59
TCR, (2006 $)	$1,270,000	$3,000,000	$1,270,000	$1,360,000
TCR, (2006 $/kW)	$12.66	$3.82	$16.02	$8.00
First-Year Annual O&M (2006 $) with 80% Capacity Factor				
PAC Consumption, $/yr	$303,000	$1,190,000	$265,000	$176,000
PAC Disposal, $/yr	$6,600	$18,800	$2,370	$1,110
Other, $/yr	$107,000	$155,000	$105,000	$107,000
Total, $/yr	$417,000	$1,370,000	$372,000	$284,000
Byproduct Impacts, $/yr	$1,080,000	$5,450,000	$758,000	$1,090,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh				
w/o byproduct impacts	0.98	0.38	1.14	0.45
with byproduct impacts	2.92	1.62	2.85	1.60
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed				
w/o byproduct impacts	$55,200	$17,200	$71,400	$13,400
with byproduct impacts	$165,000	$73,100	$179,000	$47,900

Table 10 -- Cost Estimate for 70% Mercury Removal at Bituminous Units

70% ACI Mercury Removal				
Plant	**Plant Yates Unit 1**	**Monroe Station Unit 4**	**Lee Station Unit 1**	**Portland Station Unit 1**
Capacity, MW	100	785	79	172
Fuel	Low-Sulfur Bituminous	60:40 PRB/Bit. Blend	Low-Sulfur Bituminous	Medium-Sulfur Bituminous
Coal Hg Content, lb/TBtu	5.92	5.59	3.35	8.23
Flue Gas Flow Rate, acfm	480,000	3,600,000	320,000	520,621
Unit APCD	CS-ESP & Wet FGD	SCR & CS-ESP (SO_3 FGC)	CS-ESP	CS-ESP
PAC / SEA	Super HOK	DARCO® Hg	B-PAC™	Mer-Clean™ 8-21
ACI Rate, lb/MMacf	8.98	3.38	4.83	1.39
TCR, (2006 $)	$1,270,000	$3,000,000	$1,270,000	$1,360,000
TCR, (2006 $/kW)	$12.66	$3.82	$16.02	$8.00
First-Year Annual O&M (2006 $) with 80% Capacity Factor				
PAC Consumption, $/yr	$707,000	$2,760,000	$617,000	$410,000
PAC Disposal, $/yr	$15,400	$43,500	$5,520	$2,580
Other, $/yr	$111,000	$167,000	$106,000	$107,000
Total, $/yr	$833,000	$2,970,000	$729,000	$520,000
Byproduct Impacts, $/yr	$1,080,000	$5,450,000	$758,000	$1,090,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh				
w/o byproduct impacts	1.72	0.75	1.95	0.69
with byproduct impacts	3.66	1.99	3.66	1.84
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed				
w/o byproduct impacts	$69,500	$24,000	$87,200	$14,900
with byproduct impacts	$148,000	$63,900	$164,000	$39,600

Table 11 -- Cost Estimate for 80 - 90% Mercury Removal at Bituminous Units[r]

80 - 90% ACI Mercury Removal			
Plant	**Monroe Station Unit 4**	**Lee Station Unit 1**	**Portland Station Unit 1**
Capacity, MW	785	79	172
Fuel	60:40 PRB/Bit. Blend	Low-Sulfur Bituminous	Medium-Sulfur Bituminous
Coal Hg Content, lb/TBtu	5.59	3.35	8.23
Flue Gas Flow Rate, acfm	3,600,000	320,000	520,621
Unit APCD	SCR & CS-ESP (SO_3 FGC)	CS-ESP	CS-ESP
PAC / SEA	DARCO® Hg	B-PAC™	Mer-Clean™ 8-21
ACI Rate, lb/MMacf	5.78	8.27	5.34
TCR, (2006 $)	$3,000,000	$1,270,000	$1,360,000
TCR, (2006 $/kW)	$3.82	$16.02	$8.00
First-Year Annual O&M (2006 $) with 80% Capacity Factor			
PAC Consumption, $/yr	$4,720,000	$1,060,000	$1,580,000
PAC Disposal, $/yr	$74,300	$9,460	$9,940
Other, $/yr	$165,000	$106,000	$111,000
Total, $/yr	$4,960,000	$1,170,000	$1,700,000
Byproduct Impacts, $/yr	$5,450,000	$758,000	$1,090,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh			
w/o byproduct impacts	1.20	2.95	1.94
with byproduct impacts	2.45	4.67	3.09
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed			
w/o byproduct impacts	$33,800	$103,000	$32,300
with byproduct impacts	$68,800	$163,000	$51,500

[r] For this analysis, the ACI concentration required to achieve a given level of mercury control was calculated using an adjusted non-linear algorithm that accounts for baseline mercury capture and incorporates the average long-term test results (Appendix C). If the calculated ACI concentration fell within, or reasonably close to, the range of ACI concentrations evaluated during the parametric testing campaign, then an economic analysis was performed for that level of mercury control. As a result, this table presents cost estimates for 80% ACI mercury control at the Monroe and Lee Stations, and 90% ACI mercury control at Portland Station.

Table 12 – Cost Estimate for 50% Mercury Control at PRB Units

50% ACI Mercury Removal					
Plant	**Holcomb Station Unit 1**	**St. Clair Station Unit 1**	**Meramec Station Unit 2**	**Dave Johnston Unit 3**	**Stanton Station Unit 1**
Capacity, MW	360	145	140	240	150
Fuel	PRB	85:15 PRB/Bit. Blend	PRB	PRB	PRB
Coal Hg Content, lb/TBtu	10.36	5.66	7.83	7.17	5.50
Flue Gas Flow Rate, acfm	1,194,444	751,000	555,556	925,195	574,390
Unit APCD	SDA/FF	CS-ESP	CS-ESP	CS-ESP	CS-ESP
PAC / SEA	DARCO® Hg-LH	B-PAC™	DARCO® Hg-LH	Mer-Clean™ 8	B-PAC™
ACI Rate, lb/MMacf	0.11	0.26	0.27	0.06	0.41
TCR, (2006 $)	$1,310,000	$1,280,000	$1,280,000	$1,920,000	$1,280,000
TCR, (2006 $/kW)	$3.63	$8.79	$9.16	$8.00	$8.50
First-Year Annual O&M (2006 $) with 80% Capacity Factor					
PAC Consumption, $/yr	$54,800	$76,900	$59,200	$32,100	$93,200
PAC Disposal, $/yr	$490	$688	$529	$202	$833
Other, $/yr	$105,000	$104,000	$104,000	$121,000	$105,000
Total, $/yr	$160,000	$182,000	$164,000	$154,000	$198,000
Byproduct Impacts, $/yr	$1,430,000	$792,000	$1,060,000	$1,730,000	$566,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh					
w/o byproduct impacts	0.15	0.39	0.38	0.26	0.39
with byproduct impacts	0.86	1.36	1.74	1.55	1.07
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed					
w/o byproduct impacts	$4,380	$17,200	$12,200	$7,440	$16,700
with byproduct impacts	$25,600	$60,500	$56,100	$44,000	$45,400

Table 13 – Cost Estimate for 70% Mercury Control at PRB Units

70% ACI Mercury Removal					
Plant	**Holcomb Station Unit 1**	**St. Clair Station Unit 1**	**Meramec Station Unit 2**	**Dave Johnston Unit 3**	**Stanton Station Unit 1**
Capacity, MW	360	145	140	240	150
Fuel	PRB	85:15 PRB/Bit. Blend	PRB	PRB	PRB
Coal Hg Content, lb/TBtu	10.36	5.66	7.83	7.17	5.50
Flue Gas Flow Rate, acfm	1,194,444	751,000	555,556	925,195	574,390
Unit APCD	SDA/FF	CS-ESP	CS-ESP	CS-ESP	CS-ESP
PAC / SEA	DARCO® Hg-LH	B-PAC™	DARCO® Hg-LH	Mer-Clean™ 8	B-PAC™
ACI Rate, lb/MMacf	0.27	0.60	0.62	0.14	0.95
TCR, (2006 $)	$1,310,000	$1,280,000	$1,280,000	$1,920,000	$1,280,000
TCR, (2006 $/kW)	$3.63	$8.79	$9.16	$8.00	$8.50
First-Year Annual O&M (2006 $) with 80% Capacity Factor					
PAC Consumption, $/yr	$128,000	$179,000	$138,000	$75,200	$217,000
PAC Disposal, $/yr	$1,140	$1,600	$1,230	$474	$1,940
Other, $/yr	$105,000	$105,000	$105,000	$122,000	$105,000
Total, $/yr	$234,000	$286,000	$244,000	$197,000	$324,000
Byproduct Impacts, $/yr	$1,430,000	$792,000	$1,060,000	$1,730,000	$566,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh					
w/o byproduct impacts	0.18	0.52	0.48	0.30	0.54
with byproduct impacts	0.89	1.49	1.84	1.59	1.22
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed					
w/o byproduct impacts	$3,910	$16,300	$11,100	$5,970	$16,500
with byproduct impacts	$19,000	$47,200	$42,400	$32,100	$36,900

Table 14 – Cost Estimate for 90% Mercury Control at PRB Units

90% ACI Mercury Removal					
Plant	**Holcomb Station Unit 1**	**St. Clair Station Unit 1**	**Meramec Station Unit 2**	**Dave Johnston Unit 3**	**Stanton Station Unit 1**
Capacity, MW	360	145	140	240	150
Fuel	PRB	85:15 PRB/Bit. Blend	PRB	PRB	PRB
Coal Hg Content, lb/TBtu	10.36	5.66	7.83	7.17	5.50
Flue Gas Flow Rate, acfm	1,194,444	751,000	555,556	925,195	574,390
Unit APCD	SDA/FF	CS-ESP	CS-ESP	CS-ESP	CS-ESP
PAC / SEA	DARCO® Hg-LH	B-PAC™	DARCO® Hg-LH	Mer-Clean™ 8	B-PAC™
ACI Rate, lb/MMacf	1.03	2.31	2.40	0.55	3.65
TCR, (2006 $)	$1,310,000	$1,280,000	$1,280,000	$1,920,000	$1,280,000
TCR, (2006 $/kW)	$3.63	$8.79	$9.16	$8.00	$8.50
First-Year Annual O&M (2006 $) with 80% Capacity Factor					
PAC Consumption, $/yr	$493,000	$692,000	$532,000	$291,000	$837,000
PAC Disposal, $/yr	$4,420	$6,190	$4,760	$1,830	$7,490
Other, $/yr	$107,000	$107,000	$106,000	$122,000	$108,000
Total, $/yr	$605,000	$805,000	$643,000	$414,000	$953,000
Byproduct Impacts, $/yr	$1,430,000	$792,000	$1,060,000	$1,730,000	$566,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh					
w/o byproduct impacts	0.37	1.16	0.99	0.46	1.29
with byproduct impacts	1.08	2.13	2.35	1.75	1.97
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed					
w/o byproduct impacts	$6,090	$28,500	$17,800	$7,190	$30,500
with byproduct impacts	$17,900	$52,500	$42,100	$27,500	$46,400

Table 15 – Cost Estimate for 50% Mercury Control at ND Lignite Units

50% ACI Mercury Removal			
Plant	**Leland Olds Unit 1**	**Stanton Station Unit 10**	**Leland Olds Unit 1**
Capacity, MW	220	60	220
Fuel	ND Lignite	ND Lignite	ND Lignite
Coal Hg Content, lb/TBtu	8.66	8.32	8.66
Flue Gas Flow Rate, acfm	878,049	251,789	878,049
Unit APCD	CS-ESP	SDA/FF	CS-ESP
PAC / SEA	DARCO® Hg & $CaCl_2$	DARCO® Hg-LH	Mer-Clean™ 8
ACI Rate, lb/MMacf	2.15	0.49	0.18
TCR, (2006 $)	$1,420,000	$1,270,000	$1,760,000
TCR, (2006 $/kW)	$6.45	$21.10	$8.00
First-Year Annual O&M (2006 $) with 80% Capacity Factor			
PAC Consumption, $/yr	$429,000	$49,500	$91,000
PAC Disposal, $/yr	$6,750	$443	$573
SEA Consumption, $/yr	$214,000	N/A	N/A
Other, $/yr	$108,000	$104,000	$117,000
Total, $/yr	$758,000	$154,000	$209,000
Byproduct Impacts, $/yr	$3,240,000	$579,000	$3,240,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh			
w/o byproduct impacts	0.74	0.85	0.32
with byproduct impacts	3.37	2.58	2.95
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed			
w/o byproduct impacts	$18,300	$20,300	$7,900
with byproduct impacts	$83,600	$61,500	$73,200

Table 16 – Cost Estimate for 70% Mercury Control at ND Lignite Units

70% ACI Mercury Removal			
Plant	**Leland Olds Unit 1**	**Stanton Station Unit 10**	**Leland Olds Unit 1**
Capacity, MW	220	60	220
Fuel	ND Lignite	ND Lignite	ND Lignite
Coal Hg Content, lb/TBtu	8.66	8.32	8.66
Flue Gas Flow Rate, acfm	878,049	251,789	878,049
Unit APCD	CS-ESP	SDA/FF	CS-ESP
PAC / SEA	DARCO® Hg & $CaCl_2$	DARCO® Hg-LH	Mer-Clean™ 8
ACI Rate, lb/MMacf	5.04	1.15	0.42
TCR, (2006 $)	$1,420,000	$1,270,000	$1,760,000
TCR, (2006 $/kW)	$6.45	$21.10	$8.00
First-Year Annual O&M (2006 $) with 80% Capacity Factor			
PAC Consumption, $/yr	$1,000,000	$116,000	$212,000
PAC Disposal, $/yr	$15,800	$1,040	$1,330
SEA Consumption, $/yr	$214,000	N/A	N/A
Other, $/yr	$112,000	$104,000	$118,000
Total, $/yr	$1,350,000	$221,000	$331,000
Byproduct Impacts, $/yr	$3,240,000	$579,000	$3,240,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh			
w/o byproduct impacts	1.21	1.05	0.42
with byproduct impacts	3.84	2.78	3.05
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed			
w/o byproduct impacts	$21,500	$17,900	$7,400
with byproduct impacts	$68,200	$47,300	$54,100

Table 17 – Cost Estimate for 80 - 90% Mercury Control at ND Lignite Units[s]

80 - 90% ACI Mercury Removal			
Plant	**Leland Olds Unit 1**	**Stanton Station Unit 10**	**Leland Olds Unit 1**
Capacity, MW	220	60	220
Fuel	ND Lignite	ND Lignite	ND Lignite
Coal Hg Content, lb/TBtu	8.66	8.32	8.66
Flue Gas Flow Rate, acfm	878,049	251,789	878,049
Unit APCD	CS-ESP	SDA/FF	CS-ESP
PAC / SEA	DARCO® Hg & $CaCl_2$	DARCO® Hg-LH	Mer-Clean™ 8
ACI Rate, lb/MMacf	8.65	1.98	1.64
TCR, (2006 $)	$1,420,000	$1,270,000	$1,760,000
TCR, (2006 $/kW)	$6.45	$21.10	$8.00
First-Year Annual O&M (2006 $) with 80% Capacity Factor			
PAC Consumption, $/yr	$1,720,000	$199,000	$816,000
PAC Disposal, $/yr	$27,100	$1,780	$5,140
SEA Consumption, $/yr	$214,000	N/A	N/A
Other, $/yr	$112,000	$105,000	$119,000
Total, $/yr	$2,080,000	$305,000	$940,000
Byproduct Impacts, $/yr	$3,240,000	$579,000	$3,240,000
COE Increase, 20-Year Levelized Cost (Current $), mills/kWh			
w/o byproduct impacts	1.81	1.30	0.91
with byproduct impacts	4.44	3.03	3.54
Incremental Cost of Control, 20-Year Levelized Cost (Current $), $/lb Hg Removed			
w/o byproduct impacts	$24,900	$17,300	$12,600
with byproduct impacts	$61,200	$40,100	$48,900

[s] For this analysis, the ACI concentration required to achieve a given level of mercury control was calculated using an adjusted non-linear algorithm that accounts for baseline mercury capture and incorporates the average long-term test results (see Appendix C). If the calculated ACI concentration fell within, or reasonably close to, the range of ACI concentrations evaluated during the parametric testing campaign, then an economic analysis was performed for that level of mercury control. As a result, this table presents cost estimates for 80% mercury control at the Leland Olds and Stanton Stations, and 90% mercury control via the injection of Mer-Clean™ 8 at Leland Olds Station.

IV. DISCUSSION

The plant-specific economic analyses presented in this document are based on the results of full-scale ACI field tests completed under DOE/NETL's Phase II mercury control program. As shown in Tables 6 and 7, the majority of Phase II testing is being conducted at units burning at least a partial blend of low-rank coal. The concerted effort to enhance mercury capture at units firing low-rank coal stems from Phase I field testing results at the PRB-fired Pleasant Prairie Unit 2 where total mercury removal was limited to about 65% despite the injection of conventional DARCO® Hg at flue gas concentrations as high as 30 lb/MMacf. These results led to the development, and subsequent testing, of advanced mercury control technologies (e.g., chemically-treated PAC injection and SEA coal treatment) that introduce halogens into the chlorine-deficient flue gas emitted from boilers burning low-rank coals. It is believed that the excess halogens will further promote elemental mercury oxidation and enhance flue gas mercury capture.

This analysis emulates the Phase II program as a whole, in that, the majority of field testing sites being evaluated burn at least a partial blend of low-rank coal. Specifically, this report provides cost estimates for mercury control via ACI at: (1) three bituminous-fired units and Monroe Station Unit 4 (Tables 9-11); (2) four PRB-fired units and St. Clair Station Unit 1 (Tables 12-14); and (3) three ND lignite-fired units (Tables 15-17). Moreover, mercury control cost estimates for 10 of the 12 Phase II field testing sites are based on the performance of an advanced mercury control technology: chemically-treated PAC injection at nine units; and SEA coal treatment, coupled with conventional ACI, at one unit. As shown in this report, the superior performance of chemically-treated PAC injection (in most applications) during Phase II field tests has allowed DOE/NETL to make significant strides toward achieving the near- and longer-term IEP Program performance and cost objectives for mercury control technologies.

Indeed, cost estimates for 90% ACI mercury removal are limited to the Phase II field testing sites that evaluated chemically-treated PAC injection during long-term testing. For the Phase II units included in this analysis, chemically-treated PAC injection concentrations ranging from 0.55 to 5.34 lb/MMacf are required to achieve 90% ACI mercury removal resulting in a 20-year levelized COE increase ranging from 0.37 to 1.94 mills/kWh when byproduct impacts are excluded. Meanwhile, the 20-year levelized incremental cost of 90% ACI mercury control ranges from about $6,090 to $32,300/lb Hg removed when byproduct impacts are excluded. The following sections delve into the mercury control cost estimates for each coal rank. In addition, a discussion of plant-specific and other key factors that can influence the cost of mercury control via ACI is included.

Bituminous Coal-Fired Units

While the majority of Phase II projects are focused on enhancing mercury capture at units firing low-rank coals, DOE/NETL is also funding several full-scale ACI field tests at bituminous coal-fired units. As shown in Tables 9-11, this analysis provides plant-specific cost estimates for different levels of ACI mercury control based on the performance of: (1) conventional Super HOK injection at Plant Yates Unit 1; (2) conventional DARCO® Hg injection at Monroe Station Unit 4; (3) brominated B-PAC™ injection at Lee Station Unit 1; and (4) chemically-treated Mer-Clean™ 8-21 injection at

Portland Station Unit 1. Mercury sorbent injection at each of these units took place upstream of a CS-ESP; however, Mer-Clean™ 8-21 was injected upstream of the air preheater via ALSTOM-PPL's Mer-Cure™ system. For these ACI systems, the TCR values expressed as a function of unit capacity range from $3.82/kW for the 785 MW Monroe Station Unit 4 to $16.02/kW for the 79 MW Lee Station Unit 1.

The first-year annual O&M data presented in Table 10 for 70% ACI mercury removal at these units reveals that the annual cost of PAC consumption can be impacted by several factors, including: the required ACI rate (lb/MMacf), delivered PAC price ($/lb), and the unit's flue gas flow rate (acfm). The Portland data illustrates the direct relationship between ACI rate and annual PAC consumption cost, where the lowest ACI rate (Mer-Clean™ 8-21 at 1.39 lb/MMacf) yields the minimum PAC consumption cost of about $410,000, using a delivered Mer-Clean™ 8-21 price of $1.35/lb. A comparison between the annual PAC consumption cost estimates for Yates and Portland shows the importance of delivered PAC price. For Yates, Super HOK injection at 8.98 lb/MMacf results in an annual PAC consumption cost of approximately $707,000, using a delivered Super HOK price of $0.39/lb. These data show that while the annual PAC consumption cost is higher for Yates than Portland, the delivered PAC cost differential somewhat negates the large disparity in the required ACI rate.

Meanwhile, the annual PAC consumption cost of about $2.8 million for 70% ACI mercury removal at Monroe is more than the annual PAC cost for the other three units combined, despite injection of DARCO® Hg (delivered price of $0.54/lb) at a relatively low rate of 3.38 lb/MMacf. For comparison, the annual PAC consumption cost for Lee is about $617,000, although a higher B-PAC™ (delivered price of $0.95/lb) injection rate of 4.83 lb/MMacf is required to achieve 70% ACI mercury removal. The full-load flue gas flow rate of about 3.6 MMacfm for Monroe explains the high PAC consumption cost calculated for this unit since the methodology used for estimating ACI requirements is based entirely on PAC mass per volumetric flue gas flow rate (lb/MMacf) for a desired level of mercury reduction.[t]

This report also provides 20-year levelized cost estimates (current $) for the incremental increase in COE (mills/kWh) and the incremental cost of mercury reduction ($/lb Hg removed) with and without the inclusion of potential byproduct impacts. The annual byproduct impacts, which range from about $758,000 for Lee to roughly $5.5 million for Monroe, are based on the assumption that once an ACI system is installed for mercury control, the utility would lose revenues of $18/ton from fly ash sales and incur a non-hazardous fly ash disposal fee of $17/ton.

For 70% ACI mercury removal with no byproduct impacts, the increase in COE ranges from 0.69 to 1.95 mills/kWh, while the incremental cost varies from about $14,900 to $87,200/lb Hg removed for Portland and Lee, respectively. With the inclusion of

[t] For a given level of performance (e.g., 70% ACI mercury removal) at an individual unit, annualized capital and O&M costs are independent of the mass of mercury captured. In other words, the analyses presented in this report were conducted under the assumption that the ACI concentration is independent of the flue gas mercury concentration, because the ACI system behavior mimics 1st order kinetics (i.e., a constant reduction process).

byproduct impacts, the increase in COE ranges from 1.84 to 3.66 mills/kWh, while the incremental cost varies from about \$39,600 to \$164,000/lb Hg removed. Note that the increase in COE calculated for Yates (1.72 mills/kWh) is lower than the value presented for Lee simply due to the difference in unit capacity. Meanwhile, the incremental costs for Yates (~\$69,500/lb Hg removed) and Lee are noticeably higher than the estimates provided for 70% ACI mercury removal at Monroe (~\$24,000/lb Hg removed) and Portland. The high incremental costs are a consequence of two important plant-specific factors: the low mercury content (~3.35 lb/TBtu) of the bituminous coal burned at Lee, and the 50% baseline mercury removal observed during testing at Yates, which reduce the quantity of mercury that is removed for a given level of ACI mercury control.

Cost estimates for 80% ACI mercury removal at Monroe and Lee are presented in Table 11. For Monroe, injection of DARCO® Hg at 5.78 lb/MMacf yields an increase in COE of 1.20 mills/kWh and an incremental cost of about \$33,800/lb Hg removed, when byproduct impacts are excluded. For 80% ACI mercury removal at Lee, a B-PAC™ injection rate of 8.27 lb/MMacf results in an increase in COE of 2.95 mills/kWh and an incremental cost of about \$103,000/lb Hg removed, when byproduct impacts are excluded. The economics of 90% ACI mercury removal at Portland are also shown in Table 11. Based on Mer-Clean™ 8-21 injection at 5.34 lb/MMacf, the increase in COE for Portland is 1.94 mills/kWh and incremental cost of 90% ACI mercury removal is approximately \$32,300/lb Hg removed, when byproduct impacts are excluded. When byproduct impacts are included, the increase in COE for 90% ACI mercury removal at Portland is 3.09 mills/kWh, while the incremental cost is about \$51,500/lb Hg removed.

Although Mer-Clean™ 8-21 was the only sorbent to achieve 90% ACI mercury removal at these bituminous-fired units, the Mer-Clean™ 8 sorbent demonstrated a higher mercury capture efficiency during field testing at the PRB-fired Dave Johnston Unit 3 and the ND lignite-fired Leland Olds Unit 1. The reduced efficiency of ALSTOM-PPL's Mer-Cure™ system during field testing at Portland may have been caused by elevated levels of flue gas SO_3. Mercury control research conducted by DOE/NETL and others has shown that SO_3 can interfere with the performance of ACI by competing with mercury for adsorption sites on the PAC surface.[29] SO_3 is generated in coal combustion flue gas via three mechanisms: (1) oxidation of SO_2 within the furnace; (2) further oxidation of SO_2 across SCR systems; and (3) injection of SO_3 for FGC. The lone pathway for SO_3 formation at Portland, which fires a medium-sulfur (~2%) bituminous coal, is oxidation of SO_2 within the furnace. Meanwhile, the DARCO® Hg performance data used to develop cost estimates for Monroe may have also been impacted by flue gas SO_3 since the data was generated with the SCR in-service and SO_3 FGC system operating. As discussed in Appendix B, the SO_3 FGC system at Lee had a significant impact on the mercury capture efficiency of B-PAC™ injection. However, the B-PAC™ performance data used to develop cost estimates for Lee was collected with the SO_3 FGC system idled.

PRB Coal-Fired Units

As shown in Tables 12-14, this analysis provides plant-specific cost estimates for low (50%), mid (70%), and high (90%) levels of ACI mercury control based on the performance of: (1) brominated DARCO® Hg-LH injection at Holcomb Station Unit 1 and Meramec Station Unit 2; (2) brominated B-PAC™ injection at St. Clair Station Unit 1 and Stanton Station Unit 1; and (3) chemically-treated Mer-Clean™ 8 injection at Dave Johnston Unit 3. Brominated PAC injection took place upstream of a CS-ESP at St. Clair, Meramec, and Stanton Unit 1. Mer-Clean™ 8 was injected upstream of the air preheater at Dave Johnston via ALSTOM-PPL's Mer-Cure™ system, while DARCO® Hg-LH was injected upstream of the SDA/FF configuration at Holcomb. For these ACI systems, the TCR values expressed as a function of unit capacity range from $3.63/kW for the 360 MW Holcomb Station Unit 1 to $9.16/kW for the 140 MW Meramec Station Unit 2.

Cost estimates for 90% ACI mercury removal are presented in Table 14 for each of these units. For the units equipped with a CS-ESP, the required chemically-treated ACI rate ranges from 0.55 to 3.65 lb/MMacf, resulting in annual PAC consumption costs that vary from about $291,000 to $837,000. The lower and upper bounds correspond to chemically-treated Mer-Clean™ 8 (delivered price of $1.35/lb) injection at Dave Johnston and brominated B-PAC™ (delivered price of $0.95/lb) injection at Stanton Unit 1, respectively. As shown in Figure 6, the adjusted non-linear regression curves developed for St. Clair and Meramec are nearly identical leading to similar ACI requirements for a given level of ACI mercury control. For 90% ACI mercury removal, B-PAC™ injection at 2.31 lb/MMacf yields an annual PAC consumption cost of about $692,000 for St. Clair, while the annual PAC cost of about $532,000 for Meramec is based on a required DARCO® Hg-LH (delivered price of $0.95/lb) injection rate of 2.40 lb/MMacf. Although the ACI requirement is slightly lower at St. Clair, the annual cost of PAC consumption is higher at this unit due to a higher flue gas flow rate of about 751,000 acfm. Meanwhile, DARCO® Hg-LH injection at 1.03 lb/MMacf is required to achieve 90% ACI mercury removal across the SDA/FF configuration at Holcomb, which results in an annual PAC consumption cost of about $493,000.

The reader should note that the other O&M costs (i.e., electric power requirements, O&M labor, and spare parts for the ACI system) become a more significant component of the total first-year annual O&M cost as the ACI rate required to achieve a given level of ACI mercury control decreases. For instance, chemically-treated ACI rates ranging from 0.06 to 0.41 lb/MMacf are required to achieve 50% ACI mercury removal at these units, as shown in Table 12. This yields annual PAC consumption costs that vary from about $32,100 for Dave Johnston to $93,200 for Stanton Unit 1. Meanwhile, the other O&M costs calculated for 50% ACI mercury removal at these units range from about $104,000 to $121,000. Consequently, more than half of the total first-year annual O&M cost of 50% ACI mercury removal via chemically-treated PAC injection is allocated for other costs.

Twenty-year levelized cost estimates (current $) for the incremental increase in COE and the incremental cost of mercury reduction are also presented in Tables 12-14 with and without the inclusion of potential byproduct impacts. For units equipped with a CS-ESP, the annual byproduct impacts, which range from about $566,000 for Stanton Unit 1 to roughly $1.7 million for Dave Johnston, are based on the assumption that once an ACI system is installed for mercury control, the utility would lose revenues of $18/ton from fly ash sales and incur a non-hazardous fly ash disposal fee of $17/ton. For Holcomb, the annual byproduct impacts of approximately $1.4 million assume that following the installation of an ACI system, the SDA byproducts can no longer be given away for low-value mining applications and would be subject to non-hazardous disposal at $17/ton.

The incremental cost of 70% ACI mercury removal ($/lb Hg removed) at each of these five units is lower than the value calculated for 50% ACI control. This trend occurs when the increase in mass of mercury captured outpaces the increased cost of control. For these units, the chemically-treated ACI rate needed to improve from 50 to 70% ACI mercury removal ranges from about 0.10 to 0.50 lb/MMacf leading to a small incremental increase in the cost of mercury control.

For 90% ACI mercury removal across a CS-ESP with no byproduct impacts, the increase in COE ranges from 0.46 to 1.29 mills/kWh, while the incremental cost varies from about $7,190 to $30,500/lb Hg removed for Dave Johnston and Stanton Unit 1, respectively. With the inclusion of byproduct impacts, the increase in COE ranges from 1.08 to 2.35 mills/kWh, while the incremental cost varies from about $17,900 to $52,500/lb Hg removed. The 20-year levelized costs presented for St. Clair (1.16 mills/kWh; $28,500/lb Hg removed) are higher than the values calculated for Meramec (0.99 mills/kWh; $17,800/lb Hg removed) due to plant-specific factors such as flue gas flow rate and coal mercury content. Likewise, the 20-year levelized incremental cost presented for Stanton Unit 1 is impacted by a low coal mercury content of about 5.50 lb/TBtu. For 90% ACI mercury removal at Holcomb, the increase in COE is 0.37 mills/kWh and incremental cost is about $6,090/lb Hg removed, when byproduct impacts are excluded.

ND Lignite Coal-Fired Units

This analysis provides plant-specific cost estimates for different levels of ACI mercury control (Tables 15-17) based on the performance of: (1) conventional DARCO® Hg injection, coupled with SEA coal treatment, at Leland Olds Unit 1; (2) brominated DARCO® Hg-LH injection at Stanton Station Unit 10; and (3) chemically-treated Mer-Clean™ 8 injection at Leland Olds Unit 1. At Leland Olds, DARCO® Hg was injected upstream of the CS-ESP, while Mer-Clean™ 8 was injected upstream of the air preheater via ALSTOM-PPL's Mer-Cure™ system during a subsequent Phase II field testing project. During testing at Stanton Unit 10, DARCO® Hg-LH injection took place upstream of an SDA/FF configuration. For these ACI systems, the TCR values expressed as a function of unit capacity range from $6.45/kW for the 220 MW Leland Olds Unit 1 to $21.10/kW for the 60 MW Stanton Station Unit 10. Note that the TCR for Leland Olds includes $125,000 for the installation of an SEA storage and injection system.

As shown in Table 16, this report provides a side-by-side economic comparison for 70% ACI mercury removal at Leland Olds via two advanced control technologies: SEA coal treatment that introduces excess halogens into the furnace, and chemically-treated PAC injection. With SEA coal treatment, DARCO® Hg injection at 5.04 lb/MMacf yields an annual PAC consumption cost of about $1 million. The annual SEA consumption cost of about $214,000 presented for Leland Olds is based on a constant flow rate of 2.9 lb/MMacf for the aqueous $CaCl_2$ solution (delivered cost of $0.20/lb). Meanwhile, a Mer-Clean™ 8 injection rate of only 0.42 lb/MMacf is required to achieve 70% ACI mercury removal at Leland Olds, which results in an annual PAC consumption cost of about $212,000. As a result, the total first-year annual O&M cost for 70% ACI mercury removal at Leland Olds is about four times higher with conventional DARCO® Hg injection, coupled with SEA coal treatment, as compared to chemically-treated Mer-Clean™ 8 injection. For 70% ACI mercury removal across the SDA/FF configuration at Stanton Unit 10, a DARCO® Hg-LH injection rate of 1.15 lb/MMacf yields an annual PAC consumption cost of about $116,000.

Twenty-year levelized cost estimates (current $) for the incremental increase in COE and the incremental cost of mercury reduction are also presented in Tables 15-17 with and without the inclusion of potential byproduct impacts. For Leland Olds, the annual byproduct impacts of about $3.2 million are based on the assumption that once an ACI system is installed for mercury control, the utility would lose revenues of $18/ton from fly ash sales and incur a non-hazardous fly ash disposal fee of $17/ton. For Stanton Unit 10, the annual byproduct impacts of approximately $579,000 assume that following the installation of an ACI system, the SDA byproducts can no longer be given away for low-value mining applications and would be subject to non-hazardous disposal at $17/ton.

For 70% ACI mercury removal at Leland Olds with no byproduct impacts, the increase in COE is 0.42 and 1.21 mills/kWh, while the incremental cost is about $7,400 and $21,500/lb Hg removed for chemically-treated Mer-Clean™ 8 injection and conventional DARCO® Hg injection with SEA coal treatment, respectively. For Stanton Unit 10, the increase in COE is 1.05 mills/kWh and the incremental cost of 70% ACI mercury removal is about $17,900. With the inclusion of byproduct impacts, the increase in COE ranges from 2.78 to 3.84 mills/kWh, while the incremental cost varies from about $47,300 to $68,200/lb Hg removed.

Cost estimates for 80% ACI mercury removal at Leland Olds (via conventional ACI with SEA coal treatment) and Stanton Unit 10 are presented in Table 17. For Leland Olds, injection of DARCO® Hg at 8.65 lb/MMacf yields an increase in COE of 1.81 mills/kWh and an incremental cost of about $24,900/lb Hg removed, when byproduct impacts are excluded. For 80% ACI mercury removal at Stanton Unit 10, a DARCO® Hg injection rate of 1.98 lb/MMacf results in an increase in COE of 1.30 mills/kWh and an incremental cost of about $17,300/lb Hg removed, when byproduct impacts are excluded. The economics of 90% ACI mercury removal via Mer-Clean™ 8 injection at Leland Olds are also shown in Table 17. Based on Mer-Clean™ 8 injection at 1.64 lb/MMacf, the increase in COE for Leland Olds is 0.91 mills/kWh and incremental cost of 90% ACI mercury removal is approximately $12,600/lb Hg removed, when byproduct impacts are excluded.

Key Factors Affecting the Economics of Mercury Control

The economics of mercury control via ACI can be strongly influenced by a number of key factors, including: (1) sorbent costs; (2) potential impact on byproduct management and disposal practices; and (3) plant-specific variables such as coal mercury content and baseline mercury capture. In addition, the potential demand for a significant quantity of ACI systems within a relatively short timeframe, to ensure nationwide compliance with CAMR and the patchwork of state-level regulations, could place a strain on qualified engineers, skilled laborers, and the raw materials required to erect both retrofit and new PAC storage and injection systems. As of January 2007, about 30 full-scale ACI systems have been procured by U.S. coal-fired utilities in response to Federal and state regulations, including new source permit requirements and consent decrees, according to the Institute of Clean Air Companies.[30] This figure is likely to grow as the regulatory structure for coal-fired mercury emissions becomes clear and utilities develop robust mercury control strategies.

Additional factors can influence the cost of mercury control, including: economic factors (labor rate, taxes and contingencies, economic life of capital equipment, etc.), process disruptions (unexpected or excessive outages, etc.), proximity to a reliable PAC manufacturer, and modifications to existing equipment. The estimates developed here assume an uncomplicated retrofit and minimal economic impact due to the installation of the ACI system, assuming that the installation occurs during a regularly scheduled plant outage. The estimates are also based on the assumption that mercury control via ACI will not cause any balance-of-plant impacts (e.g., the existing ESP or SDA/FF performance will not be negatively affected by the additional particulate loading). A discussion of the balance-of-plant issues observed during the Phase II long-term continuous injection trials included in this economic analysis is provided in Appendix B of this report.

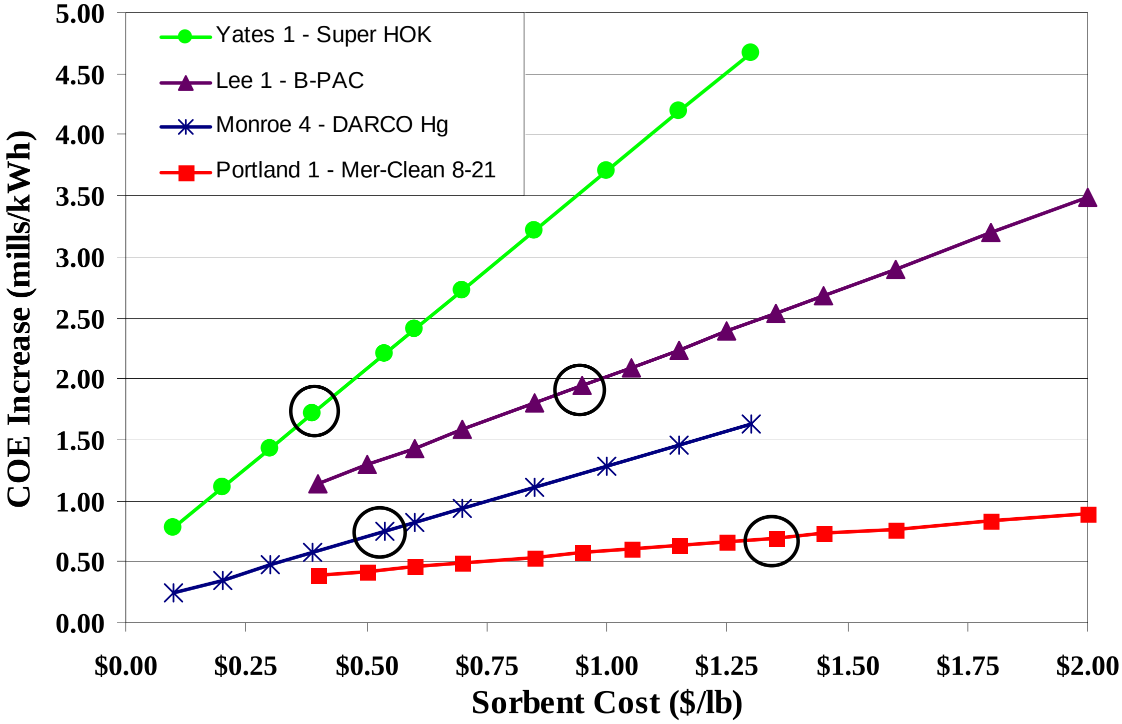
Sorbent Costs

The cost of PAC consumption, and inherently the 20-year levelized cost of mercury control via ACI, is dependent upon the required ACI rate, delivered PAC price, and the volume of flue gas being treated. In addition to PAC chemical composition, the ACI rate required to achieve a given level of mercury control can be impacted by a host of plant-specific dynamics, including, but not limited to: chlorine and sulfur contents of the coal being burned, APCD configuration, flue gas temperature, boiler efficiency/unburned carbon, and ductwork geometry in proximity to the ACI location. Chemical composition also affects PAC price since manufacturers charge a higher price for chemically-treated PAC to offset the additional production costs required to alter the sorbent's molecular structure. The impact of PAC manufacturing location on delivered sorbent price has taken on added significance following the U.S. Department of Commerce's decision to impose tariffs, ranging from 62 to 228%, on Chinese activated carbon manufacturers.[31] The February 26, 2007 determination responds to concerns that Chinese manufacturers were dumping activated carbon at less than the fair U.S. market value.

The following figures illustrate the linear relationship that exists between delivered PAC cost and the 20-year levelized incremental increase in COE for 70% ACI mercury removal without byproduct impacts. For this sensitivity analysis, the conventional PAC cost varies from $0.10/lb to $1.30/lb, while the chemically-treated PAC cost ranges from $0.40/lb to $2.00/lb. Oval symbols are provided on each figure to indicate the delivered PAC costs used to complete this economic analysis. In general, the degree of sensitivity exhibited by the increase in COE to changes in PAC cost is related to the required ACI concentration.

Data for the three bituminous units and Monroe is presented in Figure 8. The increase in COE for Yates displays the highest degree of sensitivity due to a required Super HOK injection rate of about 9 lb/MMacf. Conversely, the low Mer-Clean™ 8-21 injection rate of 1.39 lb/MMacf yields an increase in COE that remains below 1 mill/kWh for Portland. Meanwhile, the 20-year levelized increase in COE for Lee and Monroe rise with PAC cost at a similar rate due to relatively similar ACI requirements.

Figure 8 – Impact of PAC Cost on the 20-Year Levelized COE Increase due to 70% ACI Mercury Control without Byproduct Impacts for Units Firing Bituminous Coal



As shown in Figure 9, the 20-year levelized increase in COE for 70% ACI mercury removal at the PRB units and St. Clair remains below 0.90 mills/kWh even as the chemically-treated PAC cost approaches $2.00/lb. The data presented for Stanton Unit 1, St. Clair, and Meramec is similar due to required brominated PAC injection rates that range from 0.60 lb/MMacf for St. Clair to 0.95 lb/MMacf for Stanton Unit 1. For Dave Johnston, the other PRB unit equipped with a CS-ESP, the impact of chemically-treated PAC cost on the increase in COE is limited due to a required Mer-Clean™ 8 injection rate of 0.14 lb/MMacf. Likewise, the low DARCO® Hg-LH injection rate of 0.27 lb/MMacf required to achieve 70% ACI mercury removal across the SDA/FF configuration at Holcomb yields an increase in COE that ranges from about 0.15 to 0.25 mills/kWh, when byproduct impacts are excluded.

For the ND lignite data presented in Figure 10, the increase in COE for Leland Olds is highly sensitive to changes in DARCO® Hg price due to a required injection rate of 5.04 lb/MMacf, when coupled with SEA coal treatment. Meanwhile, the Leland Olds data based on a Mer-Clean™ 8 injection rate of 0.42 lb/MMacf is fairly insulated from changes in chemically-treated PAC cost. For Stanton Unit 10, a DARCO® Hg-LH injection rate of 1.15 lb/MMacf yields a 20-year levelized incremental in COE for 70% ACI mercury removal that approaches 1.50 mills/kWh as the brominated PAC cost rises to $2.00/lb.

Figure 9 - Impact of PAC Cost on the 20-Year Levelized COE Increase due to 70% ACI Mercury Control without Byproduct Impacts for Units Firing PRB Coal

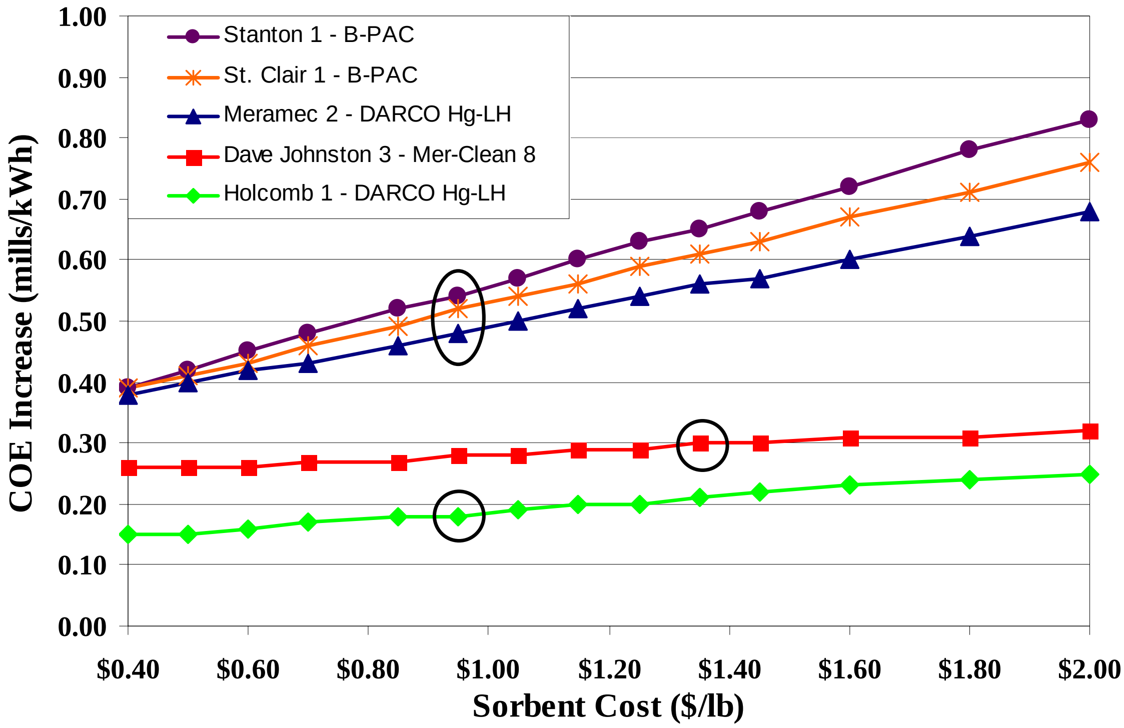
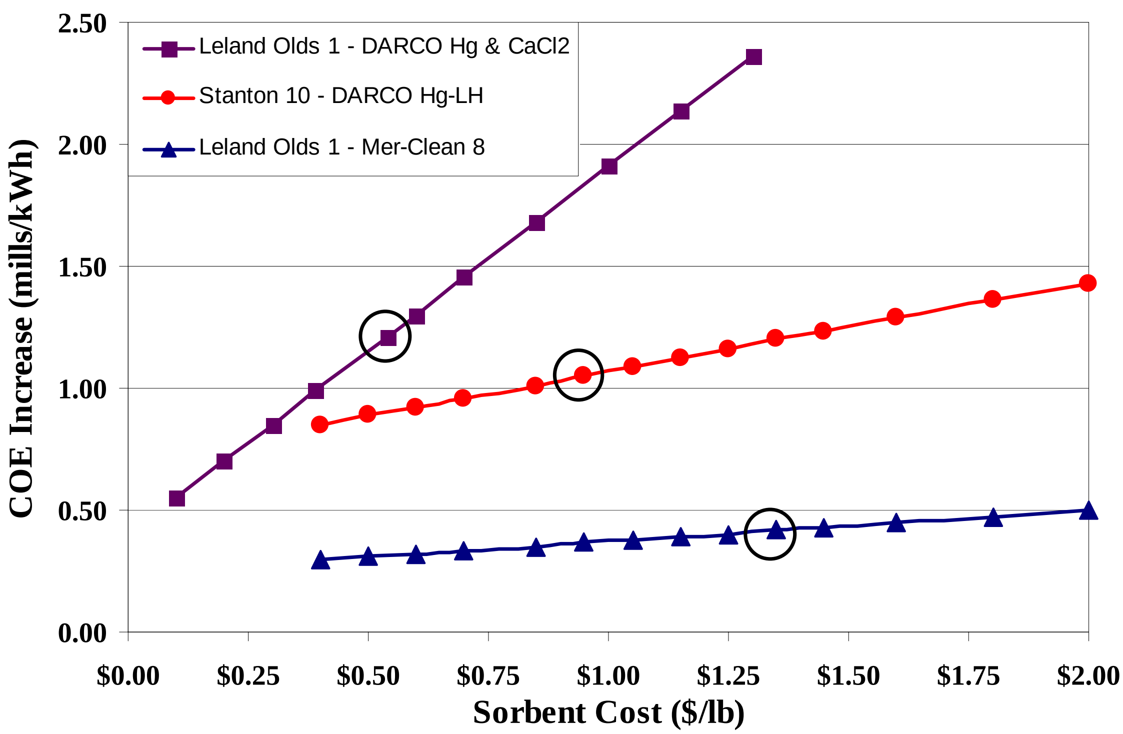


Figure 10 - Impact of Sorbent Cost on the 20-Year Levelized COE Increase due to 70% ACI Mercury Control without Byproduct Impacts for Units Firing ND Lignite Coal



The figures illustrate that the 20-year levelized incremental in COE is generally more sensitive to changes in conventional PAC cost due to the higher injection required to achieve a given level of mercury control. In other words, the performance of chemically-treated PAC injection, especially at units burning lower-rank coal, commonly outweighs the higher cost paid for these enhanced sorbents.

Potential Impacts to Byproduct Management and Disposal

Coal-fired boilers create large amounts of solid byproducts, a result of the ash and sulfur associated with coal. Particulate control devices such as ESP and FF are installed to capture fly ash and particulate matter entrained in the flue gas. The captured fly ash is either disposed in landfills or utilized in a variety of beneficial applications. Table 18 provides 2005 American Coal Ash Association (ACAA) statistics on generation and reuse of national utility fly ash and SDA ash.

Table 18 -- 2005 Fly Ash and SDA Ash Generation and Utilization Statistics

Overall Utility Coal Combustion Byproduct Statistics		
	Fly Ash	**SDA Ash**[u]
Total Generation, tons/yr	71,100,000	1,427,263
Total Utilization, tons/yr	29,118,454	159,198
% of Generation that is Utilized	40.95%	11.15%

The ACI systems discussed in this report are designed to inject PAC upstream of a particulate control device to enable simultaneous capture of the spent PAC and fly ash. This mercury control strategy leads to commingling of the PAC and fly ash that can prohibit certain fly ash recycling efforts. In particular, fly ash collected at coal-fired units that employ sorbent injection for mercury control is banned from serving as a feedstock at cement kilns following a December 2006 final rule issued by EPA.[32] Note that this ruling is based on the potential for increased mercury emissions at cement kilns rather than carbon contamination concerns. In 2005, nearly 3 million tons of fly ash served as alternative feedstock to shale or clay at about 34 U.S. cement kilns. Meanwhile, one of the highest-value reuse applications for fly ash is use as a substitute for Portland cement in concrete production. The utilization of fly ash in concrete production is particularly sensitive to carbon content as well as the surface area of the carbon present in the fly ash.

Mercury control via ACI will increase the carbon content of the fly ash with the degree of carbon contamination dependent upon the ACI concentration required to achieve a given level of mercury control. In addition, PAC has a high surface area that is ideal for mercury capture, but also promotes the adsorption of surfactants known as air entraining admixtures (AEA) that are added to the concrete slurries to stabilize an optimum amount of air in the concrete product, thus improving its workability and durability to freeze-thaw cycles.[33,34] The adsorption of AEA by the injected PAC will lead to an increased Foam Index value, which refers to the quantity of AEA required to saturate the fly ash and cement mixture, resulting in an inferior concrete product. Furthermore, the association of fly ash with mercury capture may influence marketability simply due to a perceived connection with the hazards of mercury.

[u] As submitted based on 54% coal burn.

With this in mind, the 20-year levelized costs of mercury control are presented both with and without the inclusion of byproduct impacts. The following is a discussion of the methodology used to quantify these hypothetical byproduct impacts. For units equipped with a CS-ESP, it is assumed that the utility is able to sell all fly ash collected in the ESP hoppers for $18/ton prior to ACI. The valuation used for fly ash sales in this analysis is based on estimates provided by ACAA, weighted by fly ash use distribution. However, the revenue from fly ash sales can vary significantly by regional demand and end-use. The byproduct impacts incurred once the utility installs an ACI system for mercury control assume that the fly ash can no longer be sold; instead, the utility must pay $17/ton for non-hazardous fly ash disposal. The byproduct disposal cost used for this analysis was estimated using data provided by ACAA. It is recognized that disposal costs can vary significantly based on a number of factors, including disposal method and bulk transportation method (e.g., piped or trucked).

Prior to the installation of an ACI system, it is assumed that units equipped with an SDA/FF configuration are able to simply give their byproducts away since the majority of SDA byproducts (a mixture of ash and calcium sulfite) are used for low-value applications, such as mining applications and flowable fill. After installing an ACI system, the SDA byproduct impacts assume that the material can no longer be given away; instead, the utility must pay $17/ton for non-hazardous SDA byproduct disposal (i.e., no lost revenue from sales). For this analysis, the quantity of ash and calcium sulfite generated was calculated using the coal ash and sulfur contents (Appendix A), assuming the SDA/FF configuration is able to capture all of the fly ash and 90% of the SO_2 present in the flue gas.

The cost of byproduct management and disposal is dependent on the quantity of byproducts (e.g., fly ash or SDA byproducts) generated by the coal-fired unit. Factors that affect byproduct generation include: (1) unit capacity; (2) coal ash content; (3) coal sulfur content; (4) net plant heat rate; and (5) the higher heating value (HHV) of the coal. For this analysis, the annual byproduct impacts range from approximately $566,000 for the 150 MW Stanton Unit 1 to $5,450,000 for the 785 MW Monroe Unit 4. The high value calculated for Monroe is primarily a function of the large unit capacity. A coal ash content of less than 4% for the PRB burned at Stanton Unit 1 limits the quantity of fly ash produced.

For this analysis, the captured PAC is assumed a non-hazardous byproduct under the Beville Exemption. As a result, management and disposal costs are assumed to be equivalent to those for fly ash ($17/ton). However, the possibility exists that EPA may ultimately decide that spent PAC does not fall under the existing Bevill Exemption, because it does not fit the description of a listed waste. If so, the captured PAC and fly ash would likely be managed and disposed of under regulations required by the Resource Conservation and Recovery Act (RCRA). Moreover, mercury control via ACI may trigger required compliance with RCRA Subtitle C hazardous byproduct regulations since the captured PAC would inherently possess an increased mercury concentration. RCRA Subtitle C regulations are substantially more stringent than Subtitle D non-hazardous byproduct regulations and would result in higher byproduct disposal costs.

Plant-Specific Influences on the Incremental Cost of Mercury Control

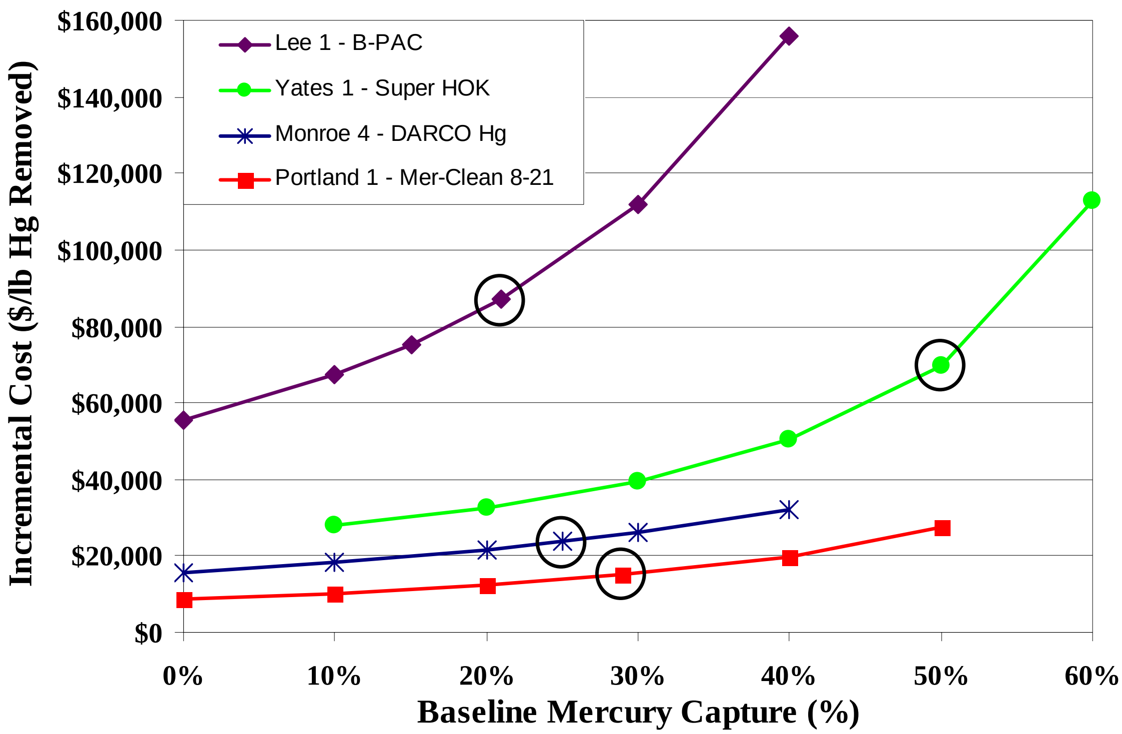
The coal mercury content and the level of baseline mercury capture are also known to influence the economics of mercury control via ACI. In particular, these site-specific parameters have a significant impact on the 20-year levelized incremental cost of mercury control ($/lb Hg removed). In general, the incremental cost of mercury control will be lower for units firing coal with high mercury content, because a larger quantity of mercury must be removed to achieve a given level of control. For example, the incremental cost for a given level of ACI mercury removal is higher for St. Clair as compared to Meramec, despite similar chemically-treated ACI requirements. In large part, the lower incremental cost calculated for Meramec can be attributed to a higher coal mercury content at this PRB unit.

The incremental cost of mercury control is also affected by the level of baseline capture observed during Phase II field testing since this analysis was conducted in a manner that yields the cost required to achieve low (50%), mid (70%), and high (80-90%) levels of mercury control "above and beyond" the plant-specific baseline mercury removal. Determining the appropriate level of baseline mercury capture for each of these Phase II units proved to be a major challenge. As part of the DOE/NETL Phase II mercury field testing program, the level of baseline mercury capture is measured several times during the baseline testing campaign and these measurements provide a good indication of the unit's typical mercury emissions in the absence of ACI. Additional baseline tests are performed prior to the injection of all candidate sorbents evaluated during the parametric testing campaign. However, field testing has shown that residual PAC remaining in the ductwork from previous injection trials may contribute to an increase in baseline mercury capture over the course of parametric testing. With that in mind, a conscious effort was made to identify the baseline mercury capture observed prior to the parametric tests involving the PAC that was ultimately selected for evaluation during the long-term continuous injection trial. For some units, the level of baseline removal observed prior to long-term testing was used to complete this analysis.

A sensitivity analysis was conducted to address the inherent variability of baseline mercury capture. Figures 11-13 illustrate the impact of baseline mercury capture variability on the 20-year levelized incremental cost of 70% ACI mercury control, when byproduct impacts are excluded. To complete this analysis, the level of baseline mercury capture was altered, while the levels of total mercury control observed during full-scale parametric tests were held constant. The resulting hypothetical parametric datasets were then subjected to the data adjustment methodology described in Appendix C to calculate the incremental cost of 70% ACI mercury removal. In addition, the flue gas mercury flow rate (lb/hr), derived from the coal mercury content, was reduced by a percentage consistent with the level of baseline mercury control being investigated at the time. This final adjustment ensures that the injected PAC is given credit for removing the appropriate quantity of mercury from the flue gas.

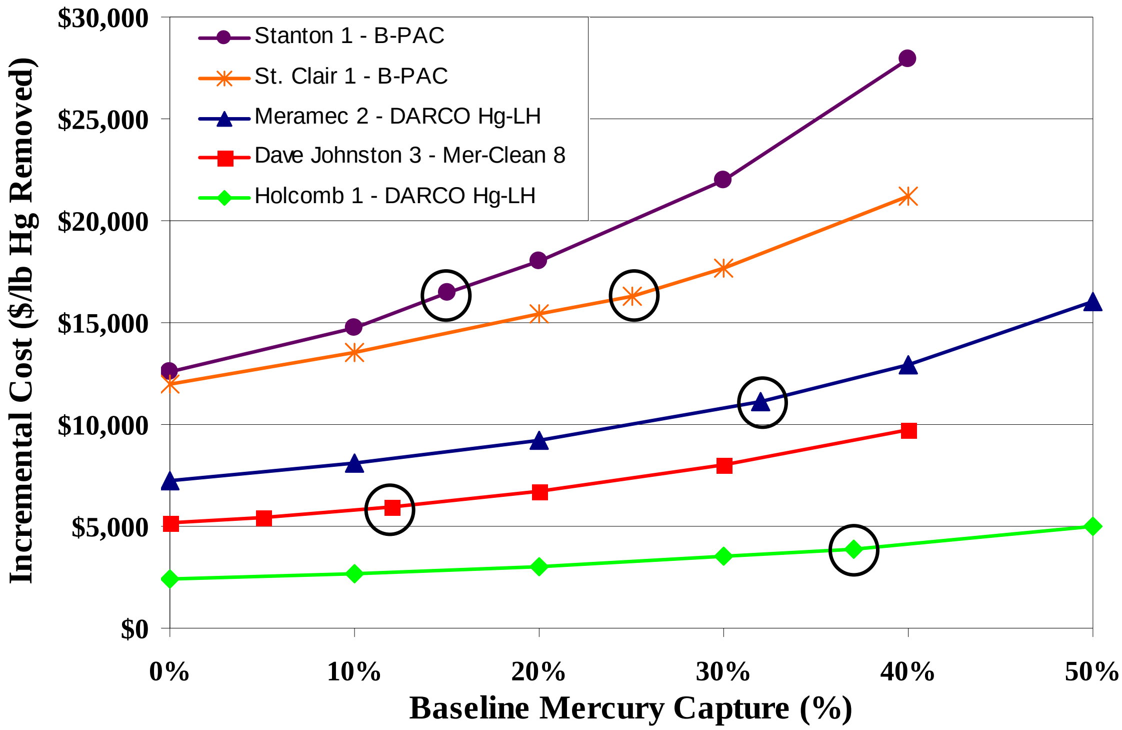
The relationship between baseline capture and the incremental cost of mercury control at the three bituminous units and Monroe is shown in Figure 11. Oval symbols indicate the baseline values of about 20%, 25%, 30%, and 50% that were used to complete the economic analyses for Lee, Monroe, Portland, and Yates, respectively. The Lee data exhibits the highest degree of sensitivity to changes in baseline capture due to a low coal mercury content of about 3.35 lb/TBtu. The data presented for Yates also displays a high degree of variability due to a low coal mercury content of 5.92 lb/TBtu, and a required Super HOK injection rate of 8.98 lb/MMacf. Meanwhile, the incremental cost of mercury control at Monroe and Portland is fairly insensitive to changes in baseline capture. The low degree of sensitivity exhibited by the Portland data can be attributed to a coal mercury content of 8.23 lb/TBtu and Mer-Clean™ 8-21 injection at only 1.39 lb/MMacf.

Figure 11 – Impact of Baseline Mercury Capture on the 20-Year Levelized Incremental Cost of 70% ACI Mercury Control without Byproduct Impacts for Units Firing Bituminous Coal



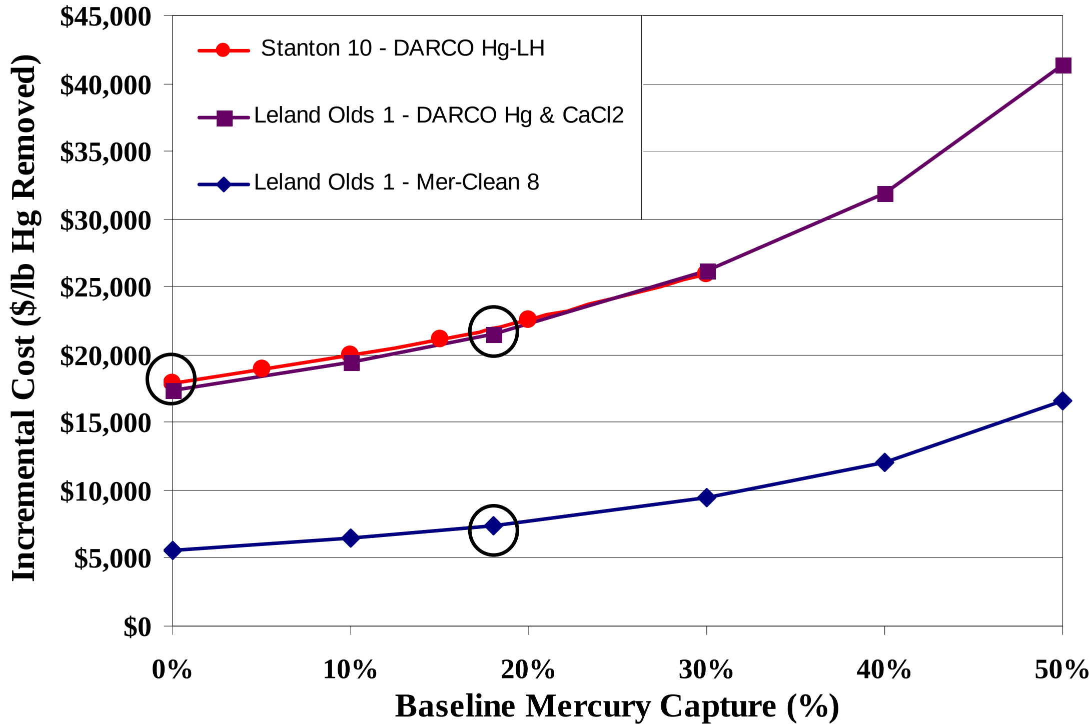
As shown in Figure 12, baseline mercury capture values of about 10%, 15%, 25%, 32%, and 37% were used to complete the economic analyses for Dave Johnston, Stanton Unit 1, St. Clair, Meramec, and Holcomb, respectively. The incremental cost of 70% ACI mercury removal for Stanton Unit 1 exhibits the highest degree of sensitivity to changes in baseline capture due to a low coal mercury content of 5.50 lb/TBtu, and a required B-PAC™ injection rate of 0.95 lb/MMacf. The shape of the sensitivity curves displayed for St. Clair, Meramec, and Dave Johnston are very similar; however, the incremental cost of control is higher for St. Clair due to lower coal mercury content of 5.66 lb/TBtu. The incremental cost of 70% ACI mercury removal at Holcomb is lowest and exhibits the smallest degree of sensitivity to changes in the level of baseline mercury capture due to high coal mercury content of 10.36 lb/TBtu, and a required DARCO® Hg-LH injection rate of 0.27 lb/MMacf.

Figure 12 -- Impact of Baseline Mercury Capture on the 20-Year Levelized Incremental Cost of 70% ACI Mercury Control without Byproduct Impacts for Units Firing PRB Coal



The relationship between baseline capture and the incremental cost of 70% ACI mercury removal at the ND lignite units is shown in Figure 13. Oval symbols indicate the baseline values of 0 and 18% that were used to complete the economic analyses for Stanton Unit 10 and Leland Olds, respectively. Note that the coal mercury content is similar for these two ND lignite-fired units: 8.66 lb/TBtu for Leland Olds, and 8.32 lb/TBtu for Stanton Unit 10. For 70% ACI mercury removal at Leland Olds, Mer-Clean™ injection at 0.42 lb/MMacf yields a lower incremental cost control that is less sensitive to changes in baseline capture as compared to the data presented for DARCO® Hg injection at 5.05 lb/MMacf, coupled with SEA coal treatment. Although the mercury content of the ND lignite coal burned at Stanton Unit 10 is relatively high, the flue gas mercury flow rate is about four times lower than the value calculated for Leland Olds due to a smaller unit capacity of 60 MW. Consequently, for a given level of baseline mercury capture, the incremental cost of control at Stanton Unit 10 is similar to the value shown for conventional ACI and SEA coal treatment at Leland Olds, despite the lower DARCO® Hg-LH injection requirement of 1.15 lb/MMacf.

Figure 13 - Impact of Baseline Mercury Capture on the 20-Year Levelized Incremental Cost of 70% ACI Mercury Control without Byproduct Impacts for Units Firing ND Lignite Coal



In general, the sensitivity curves displayed in the preceding figures show the 20-year levelized incremental cost of mercury control rising with increasing levels of baseline mercury capture. This relationship is expected, because the injected PAC is required to remove a smaller quantity of mercury to achieve a given level of mercury control as the baseline mercury capture increases.

V. SUMMARY

This report provides "study-level" cost estimates for mercury control via ACI based on preliminary results obtained from DOE/NETL's Phase II field testing of advanced mercury control technologies. The Phase II projects included in this analysis focus on longer-term (~1 month), full-scale field tests that evaluate the mercury capture efficiency of conventional ACI, chemically-treated ACI, and conventional ACI, coupled with SEA coal treatment, for a broad range of coal-ranks and APCD configurations, and are directed toward the IEP Program's near-term goal of 50 to 70% mercury removal. These enhanced mercury control strategies (i.e., chemically-treated ACI and SEA coal treatment) are intended to compensate for the lack of naturally-occurring halogens in the combustion flue gas of low-rank coals, which appeared to limit the mercury capture efficiency of conventional ACI during Phase I field tests.

The economic analysis was conducted on a plant-specific basis meaning that the cost estimates are dependent on the actual power plant operating conditions and coal properties observed during full-scale testing at the Phase II sites included in this report. In addition, the analyses were completed in a manner that yields the cost required to achieve low (50%), mid (60-70%), and high (80-90%) levels of mercury control “above and beyond” the plant-specific baseline mercury removal. In other words, the levels of mercury control discussed in this report are directly attributable to ACI. To calculate the ACI mercury capture, a data adjustment methodology was developed to account for the level of baseline mercury capture observed during parametric testing, and to incorporate the average level of mercury removal measured during the long-term continuous ACI trial. A complete discussion of the ACI data adjustment methodology, with sample calculations, is provided in Appendix C.

This approach is complicated by the variability of baseline mercury capture caused by changes in coal composition and boiler performance that can impact the quantity of unburned carbon present in the fly ash. Field testing has also shown that residual PAC remaining in the ductwork from previous injection trials may contribute to an increase in baseline mercury capture over the course of the parametric testing campaign. With that in mind, a conscious effort was made to identify the baseline mercury capture observed prior to the parametric tests involving the PAC that was selected for evaluation during the long-term continuous injection trial.

The economics of mercury control via ACI can be impacted by a number of factors, including, but not limited to:

- ACI concentration required to achieve a given level of mercury control;
- Delivered PAC cost;
- Plant-specific factors (e.g., coal mercury content, baseline mercury capture)
- Economic assumptions including economic life of capital equipment; and
- Impact to byproduct management and disposal practices (including assumption that byproducts are exempt from hazardous waste disposal requirements).

The following is a brief summary of the cost estimates developed for each of the Phase II field testing sites included in this analysis. Once again, the discussion is segregated by the type of coal burned during DOE/NETL Phase II field testing program.

Bituminous Coal-Fired Units

This analysis provides plant-specific costs estimates for different levels of ACI mercury control based on the performance of: (1) conventional Super HOK injection at Plant Yates Unit 1; (2) conventional DARCO® Hg injection at Monroe Station Unit 4; (3) brominated B-PAC™ injection at Lee Station Unit 1; and (4) chemically-treated Mer-Clean™ 8-21 injection at Portland Station Unit 1. For these ACI systems, the TCR values expressed as a function of unit capacity range from $3.82/kW for the 785 MW Monroe Station Unit 4 to $16.02/kW for the 79 MW Lee Station Unit 1.

For 70% ACI mercury removal with no byproduct impacts, the increase in COE ranges from 0.69 to 1.95 mills/kWh, while the incremental cost varies from about $14,900 to $87,200/lb Hg removed for Portland and Lee, respectively. With the inclusion of byproduct impacts, the increase in COE ranges from 1.84 to 3.66 mills/kWh, while the incremental cost varies from about $39,600 to $164,000/lb Hg removed. The incremental costs for Yates and Lee are noticeably higher than the estimates provided for 70% ACI mercury removal at Monroe and Portland. The high incremental costs are a consequence of two important plant-specific factors: the low mercury content (3.35 lb/TBtu) of the bituminous coal burned at Lee, and the 50% baseline mercury removal observed during Phase II testing at Yates, which reduce the quantity of mercury that is removed for a given level of ACI mercury control.

For 80% ACI mercury removal at Monroe, injection of DARCO® Hg at 5.78 lb/MMacf yields an increase in COE of 1.20 mills/kWh and an incremental cost of about $33,800/lb Hg removed, when byproduct impacts are excluded. For 80% ACI mercury removal at Lee, a B-PAC™ injection rate of 8.27 lb/MMacf results in an increase in COE of 2.95 mills/kWh and an incremental cost of about $103,000/lb Hg removed, when byproduct impacts are excluded. The economics of 90% ACI mercury removal at Portland were also tabulated. Based on Mer-Clean™ 8-21 injection at 5.34 lb/MMacf, the increase in COE for Portland is 1.94 mills/kWh and incremental cost of 90% ACI mercury removal is approximately $32,300/lb Hg removed, when byproduct impacts are excluded. Although Mer-Clean™ 8-21 was the only sorbent to achieve 90% ACI mercury removal at these bituminous-fired units, the performance may have been limited by flue gas SO_3. Mercury control research conducted by DOE/NETL and others has shown that SO_3 can interfere with the performance of ACI by competing with mercury for adsorption sites on the PAC surface.

PRB Coal-Fired Units

This report provides plant-specific costs estimates for low (50%), mid (70%), and high (90%) levels of ACI mercury control based on the performance of: (1) brominated DARCO® Hg-LH injection at Holcomb Station Unit 1 and Meramec Station Unit 2; (2) brominated B-PAC™ injection at St. Clair Station Unit 1 and Stanton Station Unit 1; and (3) chemically-treated Mer-Clean™ 8 injection at Dave Johnston Unit 3. For these ACI systems, the TCR values expressed as a function of unit capacity range from $3.63/kW for the 360 MW Holcomb Station Unit 1 to $9.16/kW for the 140 MW Meramec Station Unit 2.

For 90% ACI mercury removal across a CS-ESP with no byproduct impacts, the increase in COE ranges from 0.46 to 1.29 mills/kWh, while the incremental cost varies from about $7,190 to $30,500/lb Hg removed for Dave Johnston and Stanton Unit 1, respectively. With the inclusion of byproduct impacts, the increase in COE ranges from 1.08 to 2.35 mills/kWh, while the incremental cost varies from about $17,900 to $52,500/lb Hg removed. The 20-year levelized costs presented for St. Clair (1.16 mills/kWh; $28,500/lb Hg removed) are higher than the values calculated for Meramec (0.99 mills/kWh; $17,800/lb Hg removed) due to plant-specific factors such as flue gas flow rate and coal mercury content. Likewise, the 20-year levelized incremental cost presented for Stanton Unit 1 is impacted by a low coal mercury content of about 5.50 lb/TBtu. For 90% ACI mercury removal across the SDA/FF configuration at Holcomb, the increase in COE is 0.37 mills/kWh and incremental cost is about $6,090/lb Hg removed, when byproduct impacts are excluded.

Note that the incremental cost of 70% ACI mercury removal at each of these five units is lower than the value calculated for 50% ACI control. This trend occurs when the increase in mass of mercury captured outpaces the increased cost of control. For these units, the chemically-treated ACI rate needed to improve from 50 to 70% ACI mercury removal ranges from about 0.10 to 0.50 lb/MMacf leading to a small increase in the cost of mercury control.

ND Lignite Coal-Fired Units

This analysis provides plant-specific costs estimates for different levels of ACI mercury control based on the performance of: (1) conventional DARCO® Hg injection, coupled with SEA coal treatment, at Leland Olds Unit 1; (2) brominated DARCO® Hg-LH injection at Stanton Station Unit 10; and (3) chemically-treated Mer-Clean™ 8 injection at Leland Olds Unit 1. For these ACI systems, the TCR values expressed as a function of unit capacity range from $6.45/kW for the 220 MW Leland Olds Unit 1 to $21.10/kW for the 60 MW Stanton Station Unit 10. Note that the TCR for Leland Olds includes $125,000 for the installation of an SEA storage and injection system.

For 70% ACI mercury removal at Leland Olds with no byproduct impacts, the increase in COE is 0.42 and 1.21 mills/kWh, while the incremental cost is about $7,400 and $21,500/lb Hg removed for Mer-Clean™ 8 injection and conventional DARCO® Hg injection with SEA coal treatment, respectively. For Stanton Unit 10, the increase in COE is 1.05 mills/kWh and the incremental cost of 70% ACI mercury removal is about $17,900. With the inclusion of byproduct impacts, the increase in COE ranges from 2.78 to 3.84 mills/kWh, while the incremental cost varies from about $47,300 to $68,200/lb Hg removed.

For 80% ACI mercury removal at Leland Olds, injection of DARCO® Hg at 8.65 lb/MMacf, coupled with SEA coal treatment, yields an increase in COE of 1.81 mills/kWh and an incremental cost of about $24,900/lb Hg removed, when byproduct impacts are excluded. For 80% ACI mercury removal at Stanton Unit 10, a DARCO® Hg injection rate of 1.98 lb/MMacf results in an increase in COE of 1.30 mills/kWh and an incremental cost of about $17,300/lb Hg removed, when byproduct impacts are excluded. An economic analysis of 90% ACI mercury removal via Mer-Clean™ 8 injection at Leland Olds was also performed. Based on Mer-Clean™ 8 injection at 1.64 lb/MMacf, the increase in COE for Leland Olds is 0.91 mills/kWh and incremental cost of 90% ACI mercury removal is approximately $12,600/lb Hg removed, when byproduct impacts are excluded.

The preliminary Phase II field testing results are very encouraging both in terms of the level of mercury removal achieved and the levelized cost of control on a mills/kWh and $/lb Hg removed basis. Specifically, the economics of mercury control via chemically-treated ACI at units burning lower-rank PRB and lignite coals is noteworthy. The 20-year levelized incremental increase in COE for 90% ACI mercury removal via chemically-treated or brominated PAC injection remains below 1.30 mills/kWh for the four PRB units, St. Clair, and Leland Olds, when byproducts impacts are excluded. For comparison, the increase in COE calculated for 90% ACI mercury removal at the bituminous-fired Portland Station is over 1.90 mills/kWh, when byproduct are excluded.

However, it must be kept in mind that the field tests still represent relatively short-term testing at optimum conditions. While such testing provides a sound basis for evaluating performance and cost, the limited duration of the testing does not allow for a comprehensive assessment of several key operational and balance-of-plant issues associated with ACI in general and the use of chemically-treated PAC and SEA specifically. These include: (1) changes in coal characteristics (e.g., mercury and chlorine content); (2) changes in load; (3) impacts on small collection area ESPs; (4)

PAC carryover into downstream APCD; (5) corrosion issues; (6) potential off-gassing of bromine compounds; (7) formation of flue gas halides; and (8) leaching from brominated PAC byproducts.

It should also be noted that the economic analyses represent “snapshots” in time based on the methodology used, assumptions made, and conditions that were specific to the time when DOE/NETL field testing occurred. Consequently, the economics presented in this report are plant and condition specific and attempts to use this document as a tool to predict the performance of the mercury control technologies described in this report at other power plants should be conducted cautiously regardless of similarities in coal rank and APCD configuration. In addition, the economics originate from relatively small datasets in many cases. As a result, the cost of mercury control could vary significantly with the inclusion of additional ACI performance data from current and future DOE/NETL field testing.

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APPENDIX A

Power Plant and Coal Data

Economic Assumptions

Power Plant Data	Holcomb	Meramec	Yates	Leland Olds	Stanton Unit 10	St. Clair
Coal Rank	PRB	PRB	Bituminous	ND Lignite	ND Lignite	85:15 PRB/Bit
Unit Capacity, MW	360	140	100	220	60	145
Net Plant Heat Rate, Btu/kWh	10,272	11,642	11,992	11,344	10,076	10,625
Capacity Factor, %	80	80	80	80	80	80
Flue Gas Temperature, ^{o}F	290	310	310	340	300	290
Flue Gas Flow Rate, ACFM	1,194,444	555,556	480,000	878,049	251,789	751,000
Ash exiting the boiler, %	80	80	80	80	80	80
Coal Mercury Content, lb/Trillion Btu	10.36	7.83	5.92	8.66	8.32	5.66
Mercury in Flue Gas, lb/hr	0.0383	0.0128	0.0071	0.0216	0.0050	0.0087
Coal Properties						
Coal Ultimate Analysis (ASTM, as rec'd), wt%						
Moisture	26.14	26.93	6.14	36.44	34.45	22.83
Carbon	51.89	52.32	71.55	35.38	40.48	41.19
Hydrogen	6.44	5.69	4.58	6.56	2.6	-
Nitrogen	0.75	0.79	1.39	0.7	0.52	-
Sulfur	0.41	0.55	0.93	0.66	0.71	0.6
Ash	5.36	5.93	11.67	8.49	10.07	5.09
Oxygen	35.15	26.14	5.34	48.21	11.17	-
HHV, Btu/lb	8,897	8,905	12,661	6,420	6,613	9,717

Power Plant Data	Monroe	Lee	Stanton Unit 1	Dave Johnston	Leland Olds	Portland
Coal-Rank	60:40 PRB/Bit.	Bituminous	PRB	PRB	ND Lignite	Bituminous
Unit Capacity, MW	785	79	150	240	220	172
Net Plant Heat Rate, Btu/kWh	10,600	12,060	10,076	11,196	11,344	11,400
Capacity Factor, %	80	80	80	80	80	80
Flue Gas Temperature, ^{o}F	270	300	325	770	800	640
Flue Gas Flow Rate, ACFM	3,600,000	320,000	574,390	925,195	878,049	520,621
Ash exiting the boiler, %	80	80	80	80	80	80
Coal Mercury Content, lb/Trillion Btu	5.59	3.35	5.50	7.17	8.66	8.23
Mercury in Flue Gas, lb/hr	0.0465	0.0032	0.0083	0.0193	0.0216	0.0159
Coal Properties						
Coal Ultimate Analysis (ASTM, as rec'd), wt%						
Moisture	20.43	7.2	22.9	29.5	36.59	6.22
Carbon	58.4	47.4	55.59	47.52	39.36	70.79
Hydrogen	3.76	-	4.01	3.32	2.59	4.89
Nitrogen	0.92	-	0.68	0.6	0.61	1.41
Sulfur	0.57	0.78	0.27	0.41	0.6	1.98
Ash	6.69	9.93	3.67	5.37	8.49	7.48
Oxygen	9.21	-	13.01	13.27	12.41	7.23
HHV, Btu/lb	10,019	12,251	9,618	8,165	6,420	13,002

Variable O&M and Costs	
PAC Disposal Cost	$17/ton
Fly ash Disposal Cost	$17/ton
Revenue From Fly Ash Sales	$18/ton
Power Cost	$0.05/kW
Operating Labor	$45/hr
PAC Injection Maintenance Costs	5% of equipment cost
PAC Injection Periodic Replacement Items	$10,000 Flat Rate

Economic Factors	
Cost Basis - Year Dollars	Current 2006
Construction Years	0.5
Annual Inflation	3.0%
Discount Rate (MAR)	11.2%
AFUDC Rate	10.8%
First Year Fixed Charge Rate, Current$	20.7%
First Year Fixed Charge Rate, Const$	17.0%
Lev Fixed Charge Rate, Current$ (FCR)	15.7%
Lev Fixed Charge Rate, Const$ (FCR)	13.0%
Service Life, years	20
Escalation Rates :	
Consumables (O & M)	3.0%
Fuel	5.0%
Power	3.0%

APPENDIX B

Preliminary Phase II ACI Field Test Results

Phase II – Preliminary ACI Field Test Results

In September 2003, DOE/NETL selected eight new projects to test and evaluate mercury control technologies under a Phase II, Round 1 (Phase II-1) field testing solicitation. The Phase II-1 projects were initiated in 2004 and are scheduled to be completed in early-to-mid 2006. An additional six projects – representing seven technologies - were subsequently awarded in October 2004 under a Phase II, Round 2 (Phase II-2) solicitation that is scheduled for completion in 2007. Building on promising advances that resulted from the Phase I field testing program, the Phase II projects focus on longer-term (~ 1 month at optimized conditions), large-scale field testing on plants burning primarily low-rank coals or blends (with some units burning bituminous coal) and equipped with a variety of APCD configurations. Most of the fourteen projects fall under two general categories of mercury control – sorbent injection or oxidation enhancements.

Sorbent injection generically describes conventional ACI, brominated (or chemically-treated) ACI as well as the injection of non-carbon sorbents into the flue gas for mercury control. Phase II field testing also includes an evaluation of PACs designed for HS-ESP applications. Mercury oxidation enhancements are intended to improve the mercury capture efficiency of conventional ACI or downstream APCDs by converting elemental mercury to a more reactive oxidized state. For instance, coal or flue gas treatment with SEA is being investigated in conjunction with conventional ACI, while the performance of mercury oxidation catalysts is being evaluated at units equipped with a downstream wet FGD system. The figure below provides a brief description of the DOE/NETL Phase II test sites.

Coal Rank	Cold-side ESP (low SCA)	Cold-side ESP (medium or high SCA)	Hot-side ESP	TOXECON	ESP/FGD	SDA/FF or SDA/ESP
Bituminous	Miami Fort 6 Yates 1&2	Lee 1 Lee 3 Portland	Cliffside Buck	Gavin	Yates 1 Yates 1 Conesville	
Subbituminous	Crawford	Meramec Dave Johnston Stanton 1	Council Bluffs Louisa Will County	Independence		Holcomb Laramie River[b]
Lignite (North Dakota)		Leland Olds 1 Leland Olds 1			Milton Young	Antelope Valley 1 Stanton 10 Stanton 10
Lignite (Texas)						
PRB / Bit Blend		St. Clair Monroe				
TX Lignite / PRB Blend				Big Brown	Monticello Monticello Monticello	

- Sorbent Injection
- Oxidation Additive
- Chemically-treated sorbent
- Sorbent Injection & Oxidation Additive
- Oxidation Catalyst
- Other – MERCAP, FGD Additive, Combustion

Sunflower Electric's Holcomb Station Unit 1
Full-scale field testing was conducted at the subbituminous-fired unit equipped with a SDA/FF configuration as part of the Phase II-1 project entitled *Evaluation of Sorbent Injection for Mercury Control*. Several mercury control technologies were investigated at Holcomb, including: (1) coal blending; (2) conventional ACI; (3) coal and flue gas treatment with halogenated chemical additives; and (4) brominated/chemically-treated ACI. However, the economics presented in this report are based on mercury control via the injection of brominated DARCO® Hg-LH since this PAC was evaluated during the 30-day long-term test. Field testing was completed in August 2004. Some particulars of the test site are provided in the following graphic.

Sunflower Electric's Holcomb Station

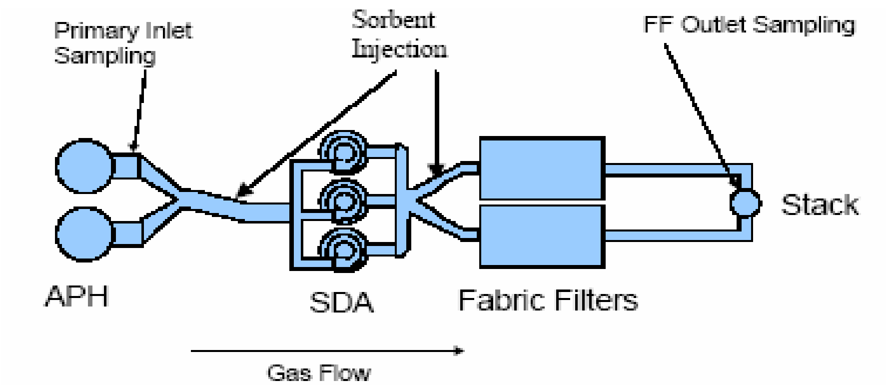
- 360 MW opposed-fired boiler
- Particulate Control
  - Fabric Filter
- Sulfur Control
  - Spray Dryer Absorber
- PRB Subbituminous Coal
  - 8,897 Btu/lb
  - 0.41% S
  - 0.078 ppm Hg
  - 5.83 ppm Cl
- SDA Inlet Temperature: 290°F

The tests were conducted in three phases (baseline, parametric, and long-term testing). Baseline mercury capture was only 13% across the SDA/FF while burning 100% PRB coal. A portion of the parametric tests was devoted to mercury control via coal blending. Blending 15% western bituminous coal with the PRB increased mercury capture to almost 80%. The mercury concentration of the western bituminous coal was similar to the PRB, but the chlorine concentration was higher (106 µg/g vs. 8 µg/g).

Three PACs were evaluated during parametric testing: (1) NORIT's DARCO® Hg – a conventional PAC; (2) Calgon 208CP - a highly activated, but untreated PAC; and (3) NORIT's brominated DARCO® Hg-LH. Total mercury removal was limited to approximately 50% with the injection of DARCO® Hg and 208CP at a flue gas injection concentration of 1.0 lb/MMacf. A proprietary chemical additive, ALSTOM Power's KNX, increased mercury removal from 50% to 86% when used with DARCO® Hg at 1.0

lb/MMacf. The KNX additive decreased the elemental mercury fraction at the air preheater outlet from 70-90% to 20-30%. However, there was no improvement in mercury capture using the KNX without ACI. Meanwhile, DARCO® Hg-LH was able to achieve approximately 75% mercury removal at an injection concentration of 0.7 lb/MMacf.

The results described above suggest that the presence of excess halogens has a significant impact on the mercury capture efficiency of ACI. The importance of halogens was also characterized by injecting PAC downstream of the SDA as shown in the following sketch.[v] With a DARCO® Hg injection concentration of 5.7 lb/MMacf, 90% mercury removal was observed with injection upstream of the SDA while mercury capture was less than 35% when ACI occurred downstream of the SDA.[w] The results indicate that adsorption of halogens by DARCO® Hg is a critical component of mercury control via conventional ACI. Conversely, the ACI location had no impact on the performance of DARCO® Hg-LH.

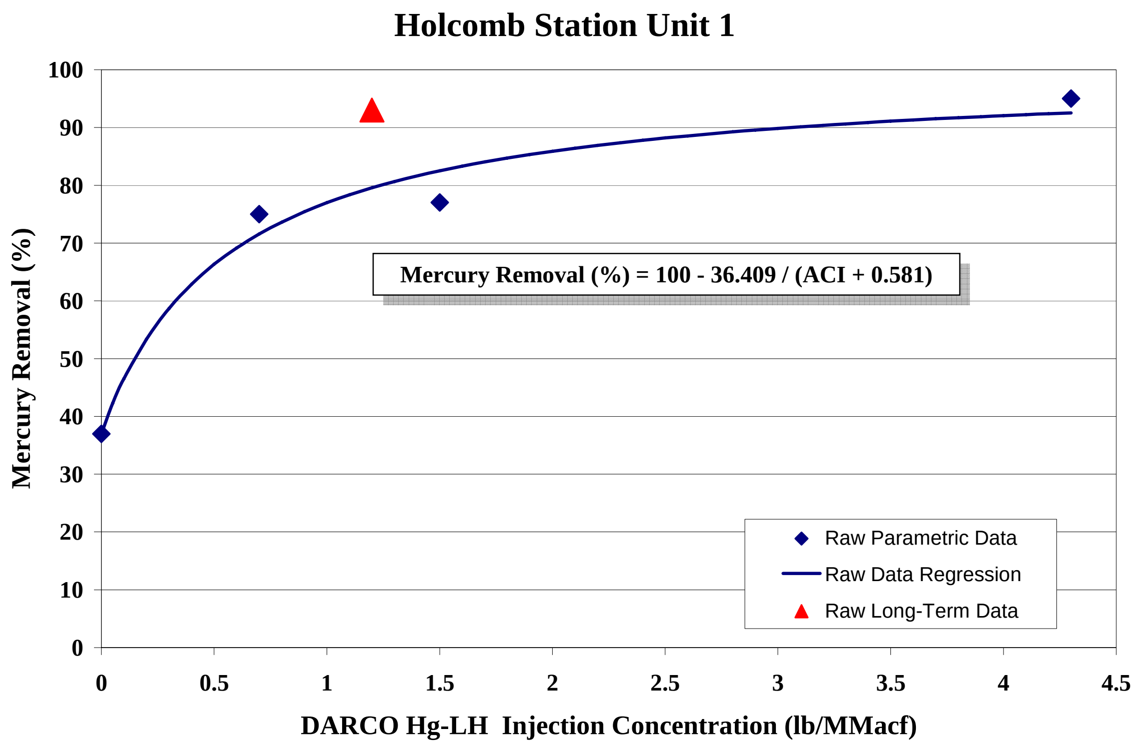


The mercury capture efficiency of DARCO® Hg-LH is shown in the following figure. The performance data shown below was observed with the unit firing 100% PRB coal. The high baseline mercury removal of approximately 37% observed during parametric testing was likely caused by PAC remaining in the system from previous parametric tests. The diamond symbols represent the limited and potentially unreliable parametric dataset. In fact, tests conducted at two DARCO® Hg-LH injection concentrations (1.5 and 4.3 lb/MMacf) were concluded after less than 130 minutes whereas the typical parametric test lasted 6-8 hours to ensure the system had reached equilibrium. However, the complete dataset was used to develop the least squares curve-fit of the parametric performance data as a function of DARCO® Hg-LH injection concentration that is also shown in the following figure.

DARCO® Hg-LH was injected upstream of the SDA for 30 days from July 7 through August 6, 2004. For the first five days of testing, the injection concentration was

[v] Results from EPA M26A tests conducted during the baseline test period indicate that HCl and HF were fairly low at the inlet to the SDA (0.5 and 1.5 ppm respectively) and 41% of the HCl and 75% of the HF was removed in the SDA.
[w] The injection concentration in pounds per *actual* cubic foot, which was calculated at the SDA inlet temperature for comparison purposes, is approximately 17% higher at the SDA outlet location due to the reduced gas volume at the lower temperatures (175ºF downstream of the SDA as compared to 290ºF upstream of the SDA).

increased until 90% mercury removal was achieved. From Day 6 through 30, the DARCO® Hg-LH injection concentration was set for nominally 1.2 lb/MMacf, resulting in an average mercury removal of 93%.[x] The average long-term performance of DARCO® Hg-LH is represented by the red triangle shown below.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the DARCO® Hg-LH injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 36.409
b = 0.581

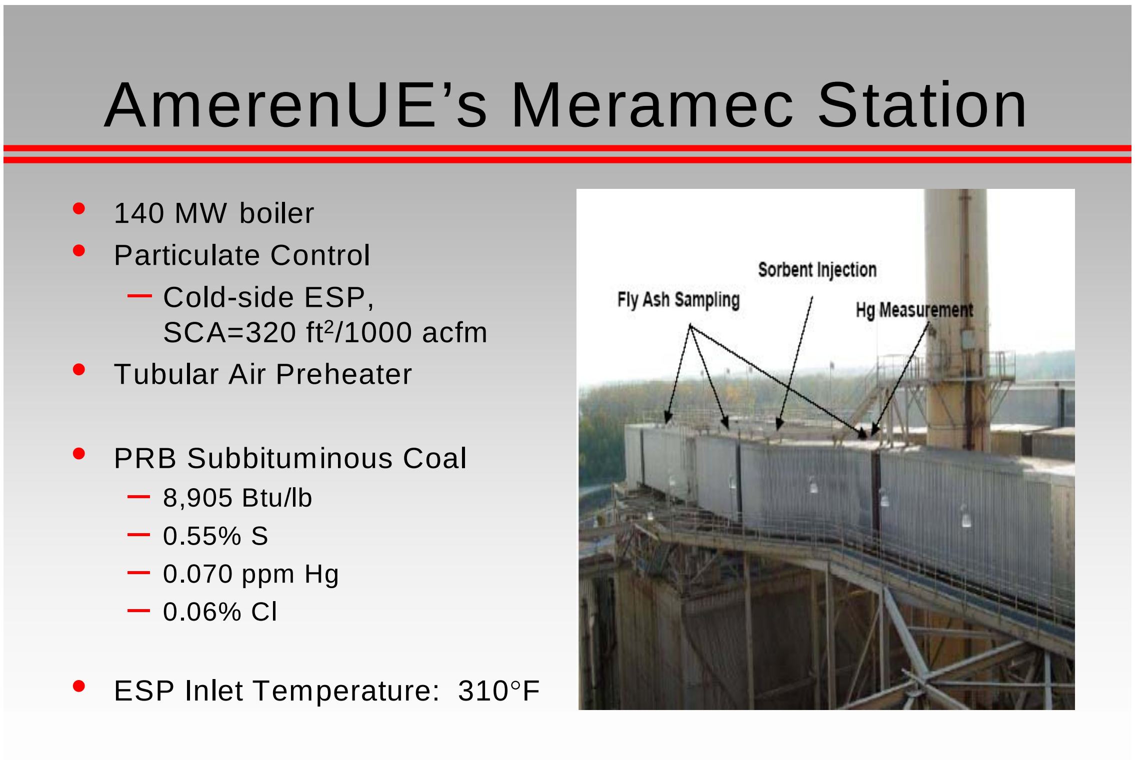
During the 30-day long-term test, no adverse balance-of-plant impacts were noted and excess levels of bromine in the flue gas were not observed. In addition, neither the pressure drop across the FF nor the stack opacity was affected by the presence of DARCO® Hg-LH. Although a 30-day test is too short for a full evaluation of the impacts of ACI on FF bag life, the results will indicate if a catastrophic failure is inevitable. A bag was removed from the baghouse, analyzed for strength, and visually inspected. The results indicated that no loss of strength was apparent and no unusual visual features were noted.

[x] The standard operation at this unit is to recycle approximately 75% of the FF effluent back into the SDA. Therefore, during the long-term continuous injection trial a portion of the injected DARCO® Hg-LH was recycled back into the SDA, which may have contributed to the high level of mercury control observed at this unit. Not all units equipped with the SDA/FF configuration utilize recycle.

The high mercury removal efficiency observed at Holcomb Unit 1 during full-scale field testing may be a product of somewhat unique operating conditions. The standard operation at this unit is to recycle approximately 75% of the material collected in the FF back into the SDA. Therefore, during continuous ACI some injected PAC will also be recycled into the SDA and may improve the overall mercury removal. Not all units equipped with the SDA/FF configuration utilize recycle.

AmerenUE's Meramec Station Unit 2

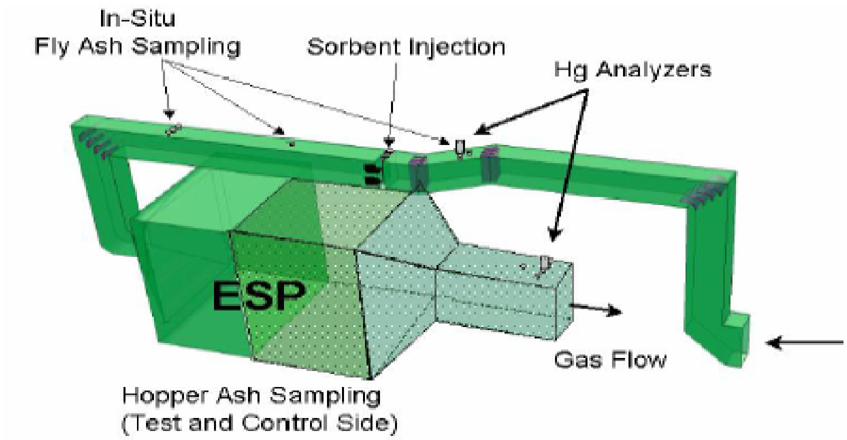
Full-scale field testing was conducted at the subbituminous-fired unit equipped with a CS-ESP as part of the Phase II-1 project entitled *Evaluation of Sorbent Injection for Mercury Control*. Several mercury control technologies were investigated at Meramec, including: (1) conventional ACI; (2) coal or flue gas treatment with halogenated chemical additives; and (3) brominated (or chemically-treated) ACI. However, the economics are based on mercury control via DARCO® Hg-LH injection since this PAC was evaluated during the 35-day long-term test. Field testing was completed in November 2004. Some particulars of the test site are provided in the following graphic.



Baseline mercury capture across the CS-ESP ranged from 15-18% while burning 100% PRB coal. During the parametric tests with DARCO® Hg-LH, Unit 2 experienced an outage in mill B resulting in higher variability in the vapor-phase mercury concentration at the ESP inlet likely caused by rapid changes in the quantity of unburned carbon as measured by the loss-on-ignition (LOI) test method. The LOI carbon variability may have contributed to higher levels of particulate-bound mercury at the CS-ESP inlet and consequently higher than normal baseline mercury removal of approximately 32% across the CS-ESP. In addition, Unit 2 operated at a reduced load of approximately 115 MW due to the mill outage.

Two methods for mercury control were evaluated during parametric testing – ACI (using either DARCO® Hg or DARCO® Hg-LH) and ALSTOM Power's KNX coal additive (with and without conventional DARCO® Hg injection). With a DARCO® Hg injection concentration of 5 lb/MMacf, total mercury removals of 88% and 74% were achieved with and without the addition of halogenated KNX coal additive, respectively. With the KNX coal additive alone, mercury removal ranged from 57-64% compared to 22-34%

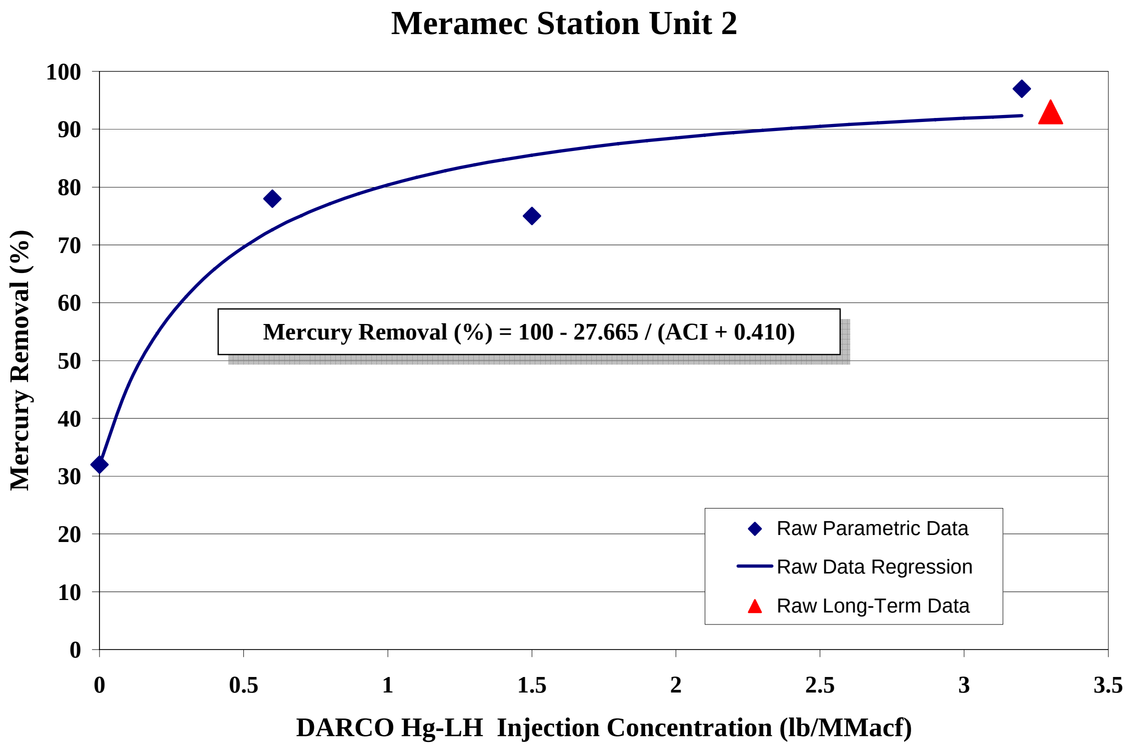
under baseline conditions during the same time period. An illustration of the PAC injection and mercury sampling locations is provided below.



The following figure displays the mercury capture efficiency of DARCO® Hg-LH. The diamond symbols represent the raw parametric data. For example, 97% mercury removal was observed at a DARCO® Hg-LH injection concentration of 3.2 lb/MMacf. However, as explained above, the baseline mercury removal was elevated during parametric tests due to a mill outage. Residual PAC from previous tests may have also been a contributing factor to the high co-benefit mercury capture. Also shown on the figure is a least squares fit of mercury control performance as a function of DARCO® Hg-LH injection concentration.

During the long-term continuous injection trial, DARCO® Hg-LH was injected upstream of the CS-ESP from October 14 through November 17, 2004. For the first five days of testing, an average injection concentration of 1 lb/MMacf was required to achieve 60-70% mercury removal. The DARCO® Hg-LH injection concentration was set for nominally 3.3 lb/MMacf resulting in an average mercury removal of 93% for the remainder of the long-term test. The average long-term performance of DARCO® Hg-LH is represented by the red triangle shown below.

Approximately 30% of the total mercury entering the CS-ESP was particulate bound during the 35-day continuous injection period at Meramec Station Unit 2. The combustion characteristics present during the long-term test resulted in higher than expected LOI carbon in the ash. The high levels of LOI carbon coupled with the high surface area present in Meramec's tubular air pre-heater (APH) and the long duct run between the APH and CS-ESP likely contributed to a higher fraction of particulate-phase mercury than typically observed for units firing PRB coal with lower LOI and regenerative APHs, and may have contributed to the high overall mercury removal observed at this site.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the DARCO® Hg-LH injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

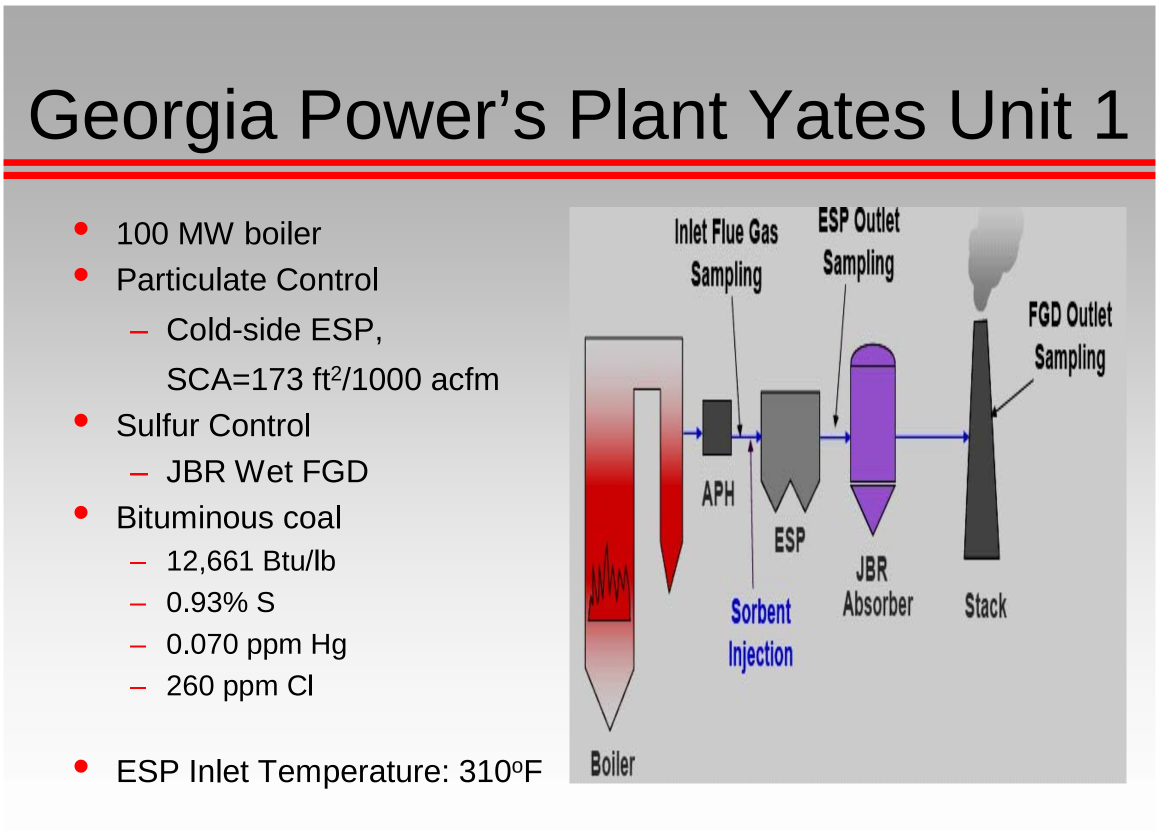
Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 27.665
b = 0.410

As at Holcomb, no adverse balance-of-plant impacts were observed during the long-term test and no excess levels of bromine were measured in the flue gas. In particular, the Synthetic Groundwater Leaching Procedure (SGLP) results revealed that 67% of the bromine in the control-side ash samples leached within 18 hours and 80% within 30 days. For the test-side ash samples where DARCO® Hg-LH injection occurred, the baseline bromine content was higher, but only 31% of the bromine leached within 18 hours and 55% within 30 days. Furthermore, Method 1311, Toxicity Characteristic Leaching Procedure (TCLP) results showed mercury levels below the detection limit in the leachate solution. In addition, there was no measurable increase in stack opacity, SO_2, or NO_x emissions and ACI did not impact the performance of the ESP during the long-term test.

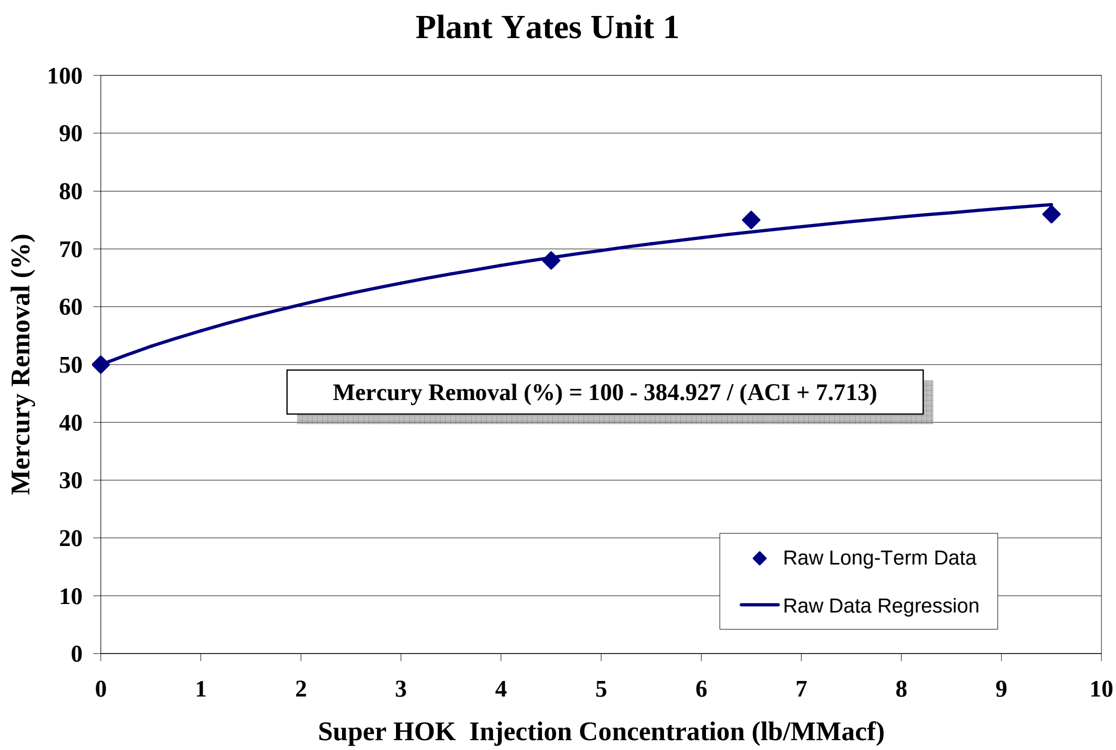
Georgia Power's Plant Yates Unit 1

Full-scale field testing was conducted at the bituminous-fired unit equipped with a CS-ESP as part of the Phase II-1 project entitled *Sorbent Injection for Small ESP Mercury Control in Low Sulfur Eastern Bituminous Coal Flue Gas*. The objectives of this project were to: (1) demonstrate the ability of various PACs to remove mercury from full-scale units configured with small specific collection area (SCA) ESPs; (2) document the impacts of ACI on small-SCA ESP and wet FGD scrubber operations; and (3) evaluate the effect of ACI on combustion byproduct properties. Based on parametric test results, Super HOK - a conventional PAC developed in Germany, was selected for evaluation during the 30-day long-term test conducted on Unit 1. Testing was completed in December 2004. Some particulars of the test site are provided in the following graphic.



During baseline tests, average mercury removal was approximately 35%. However, the baseline mercury capture was approximately 50% across the CS-ESP (80% across the CS-ESP and wet FGD) during parametric testing. Parametric tests lasting approximately two hours each were conducted on Unit 1 at various feed rates using two conventional PACs (NORIT's DARCO® Hg and RWE Rhinebraun's Super HOK) as well as Ningxia Huahui's iodine-impregnated NH Carbon. Performance was similar for the three PACs with maximum mercury removal of approximately 60% across the ESP using an ACI concentration of 6 lb/MMacf. Additional parametric tests performed on Unit 2 revealed that the dual NH_3/SO_3 flue gas conditioning system had no impact on the mercury removal efficiency of DARCO® Hg.

As mentioned above, the mercury capture efficiency of Super HOK was evaluated during the 30-day long-term test that took place in November through December 2004. In contrast to other long-term tests, the ACI concentration varied from 0-16 lb/MMacf in order to evaluate the effect on ESP outlet particulate emissions. For the most part, the Super HOK injection concentration fluctuated between 4 and 10 lb/MMacf with mercury removal ranging from 50-91% across the CS-ESP.[y] The average mercury capture observed during the long-term test as well as a least squares fit of mercury control performance as a function of Super HOK injection concentration are displayed in the following figure.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the Super HOK injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 384.927
b = 7.713

At the conclusion of the long-term continuous injection trial, a second round of parametric testing was conducted in January 2005.[35] These short-term tests evaluated a Coarse HOK sorbent, DARCO® Hg-LH, a 50:50 mixture of DARCO® Hg and Miller (PRB) ash, and DARCO® Hg for reference. A Coarse HOK injection concentration of

[y] During long-term testing, Super HOK injection concentrations of 4.5 lb/MMacf (~12 days), 6.5 lb/MMacf (~4 days), and 9.5 lb/MMacf (~4 days) were required to achieve average mercury removals of approximately 68%, 75%, and 76%, respectively.

16.2 lb/MMacf was required to achieve 77% total mercury removal across the CS-ESP. A DARCO® Hg-Miller ash injection concentration of 10.4 lb/MMacf (equivalent to 5.2 lb/MMacf of DARCO® Hg) was required to achieve 74% total mercury removal across the CS-ESP. For comparison, a DARCO® Hg injection concentration of 5.2 lb/MMacf yielded a total mercury removal of 69% across the CS-ESP. Mercury removal across the CS-ESP appeared to plateau at 82% with a brominated DARCO® Hg-LH injection concentration of 10.4 lb/MMacf. During DARCO® Hg-LH injection, a significant increase in the level of hydrogen bromide (HBr) in the flue gas was observed. Under baseline conditions, Method 26 measurements showed an HBr flue gas concentration of 0.18 ppmv. The HBr flue gas concentration increased to 0.86 ppmv and 1.20 ppmv during the injection of DARCO® Hg-LH at feed rates of 143 lb/hr and 200 lb/hr, respectively. Since DARCO® Hg-LH is brominated; this suggests that a portion of the bromine associated with the carbon desorbed during injection. Furthermore, these data imply that the amount of bromine desorbed into the flue gas is related to the DARCO® Hg-LH injection concentration.

Plant Yates was selected for long-term testing, in part, to gain a better understanding of the effect of ACI on small-SCA ESP and wet FGD operation. Erratic ESP arcing behavior was observed during baseline and short-term ACI parametric tests conducted in Spring 2004. Subsequent inspection of the ESP internals revealed the presence of damaged (i.e., carbon "baked" onto the surface) and broken stand-off insulators that may have caused, or at least contributed to the irregular and potentially detrimental ESP performance observed during these tests. However, it is unclear when the ESP damage occurred, or if the damage was a direct result of the ACI trials. In October 2004, the damaged insulators were either repaired or replaced during a scheduled maintenance outage. This allowed plant operators to monitor the ESP electrical behavior for approximately one month prior to the long-term continuous ACI trial, and compare the baseline ESP performance to that observed during ACI. Analysis of the ESP electrical behavior focused on the first (A) field, because arcing was most severe in the initial electrical field.

In an effort to determine the effect of load and ACI concentration on the arcing rate in field A, raw ESP data was collected from 10/13/04 (immediately following the maintenance outage) until 2/1/05 (approximately 1.5 months after the long-term Super HOK injection test was completed) and reduced to hourly averages. During the long-term injection test, Yates Unit 1 operated at low load (50-60 MW) and high load (95-107 MW) while the Super HOK injection concentration varied from 0-16 lb/MMacf as mentioned above. The following observations were made after sorting the ESP data based upon load and ACI concentration.

- *The arcing rate in field A was higher during ACI.* At low load, the average arc rate was 0.5 arcs per minute (apm) prior to, 4-5 apm during, and 1.2 apm following the long-term injection trial.
- *The arcing rate in field A was higher during high load versus low load.* With a Super HOK injection concentration of 4-5 ln/MMacf, the average arc rate was 4 apm at low load and 17 apm while operating at high load conditions.
- *At low load, the arcing rate in field A appeared to be independent of the Super HOK injection concentration.* Average arc rates of 4.6 apm and 5.2 apm were

observed at ACI concentrations of 4 lb/MMacf and greater than 7 lb/MMacf, respectively.

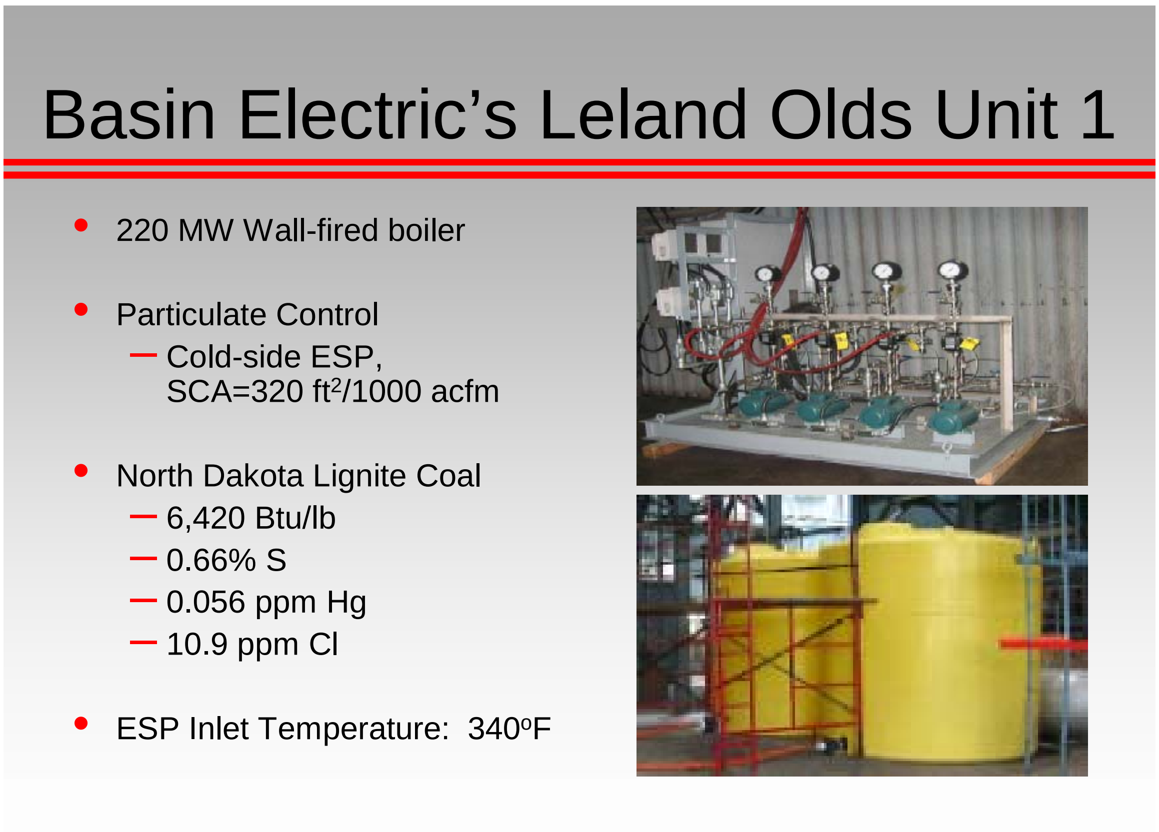
- *At high load, the arcing rate in field A may increase with ACI concentration.* The average arc rate was 17 apm at a Super HOK injection concentration of 4-5 lb/MMacf, while the average arc rate was approximately 29 apm with an ACI concentration greater than 7 lb/MMacf.
- *The long-term injection test caused no visible physical damage to the ESP.* However, it remains unclear what effect the increased arcing rate will have on ESP performance over longer time periods.

The impact of continuous Super HOK injection on the ESP outlet particulate matter concentration was quantified by taking single-point EPA Method 17 transverses. Approximately 70% of the data fell within or below the range of ESP outlet particulate matter concentrations measured during baseline testing. For the 30% of data that exceeded the measured baseline concentrations, there did not appear to be any correlation between the ACI concentration and the ESP outlet particulate matter concentration. However, the presence of carbon on the Method 17 filters confirmed the breakthrough of carbon from the small-SCA ESP.

Samples of the wet scrubber slurry were also taken periodically. The slurry samples were an unusually dark color (suggesting PAC carryover from the ESP) during a two-week period when the ACI concentration ranged from 4-6 lb/MMacf. Prior to and subsequent to this time period, the scrubber slurry did not show any visual evidence of carbon contamination even though the ACI concentration exceeded 10 lb/MMacf at times.

Basin Electric's Leland Olds Unit 1

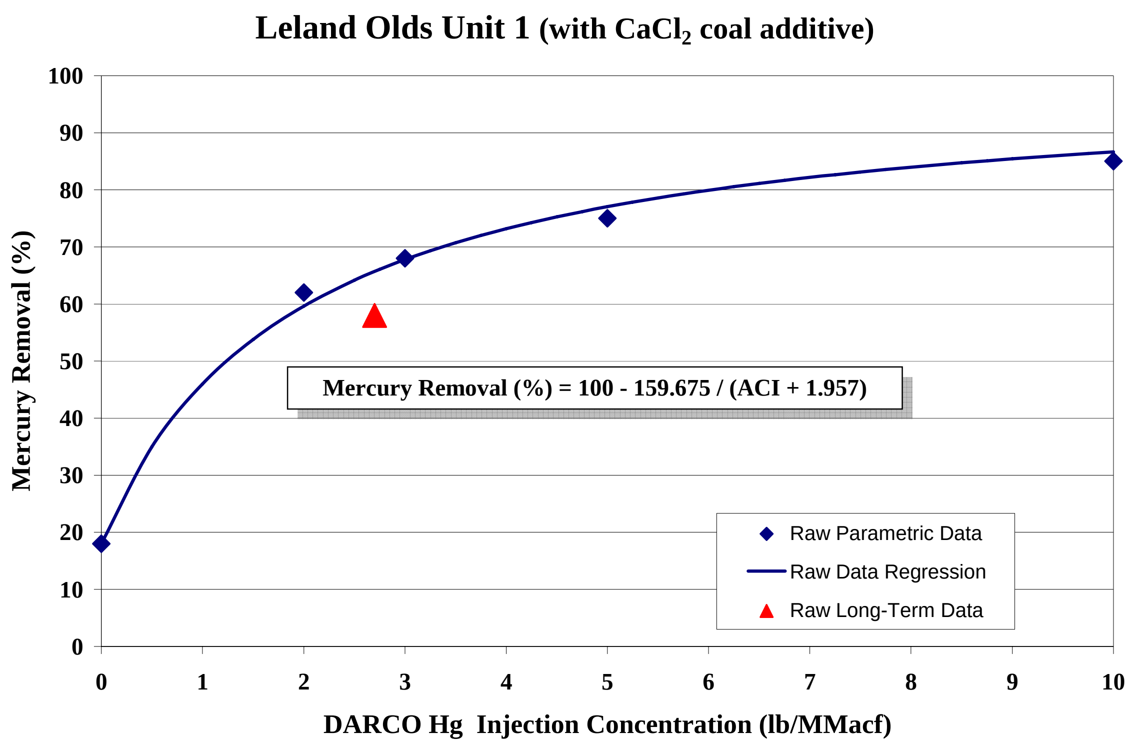
Full-scale field testing was conducted at the ND lignite-fired unit equipped with a CS-ESP as part of the Phase II-1 project entitled *Enhancing Carbon Reactivity for Mercury Control in Lignite-Fired Systems*. The primary objective of this project was to evaluate the improved mercury capture efficiency of conventional ACI when the low-rank coal is treated with an SEA prior to combustion. This technology is intended to serve as an alternative mercury control strategy for units that produce halogen-deficient flue gas from the combustion of low-rank coals. The economics presented in this report are based on the mercury capture observed with the addition of an SEA (i.e., aqueous $CaCl_2$ solution) to the coal in conjunction with DARCO® Hg injection during parametric and long-term testing with the unit firing 100% ND lignite. Testing was completed in May 2004. Some particulars of the test site are provided in the following graphic.



Approximately 56% of the total mercury entering the ESP was elemental resulting in a baseline mercury removal of 18% across the CS-ESP while firing 100% ND lignite coal. During parametric testing, DARCO® Hg injection concentrations of 3 lb/MMacf and 10 lb/MMacf were required to achieve total mercury removals of approximately 47% and 64%, respectively.

The primary objective of this project was to evaluate the mercury capture efficiency of DARCO® Hg when the ND lignite coal is treated with an aqueous $CaCl_2$ solution prior to combustion. With a constant $CaCl_2$ feed rate that is equivalent to adding approximately 500 ppm chlorine to the coal, total mercury removal of 68% and 85% were observed at DARCO® Hg injection concentrations of 3 lb/MMacf and 10 lb/MMacf, respectively.

Based on the parametric results, the 30-day long-term test was conducted with a constant $CaCl_2$ feed rate of about 2.9 lb/MMacf and a DARCO® Hg injection concentration of 2.7 lb/MMacf resulting in 58% average mercury removal across the CS-ESP. The parametric dataset is represented by the small diamond symbols displayed on the following figure. The red triangle corresponds to the average mercury capture observed during the long-term test. Also shown on the figures is a least squares curve-fit of the parametric data as a function of DARCO® Hg injection concentration.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the DARCO® Hg injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 159.675
b = 1.957

One week of parametric testing was devoted to coal blending where a blend consisting of 30% PRB coal was evaluated. With a $CaCl_2$ feed rate of 1 lb/MMacf, total mercury removal of approximately 58% and 66% was observed at DARCO® Hg injection concentrations of 3 lb/MMacf and 5 lb/MMacf, respectively. In addition, approximately 78% mercury removal was achieved with a $CaCl_2$ feed rate of 7 lb/MMacf and a DARCO® Hg injection concentration of 3 lb/MMacf. The results obtained from these short-term coal blending trials reveal that the addition of excess halogens to the flue gas is required to achieve high levels of mercury capture when firing low-rank coals.

No adverse balance-of-plant impacts were observed during the long-term test and no excess halogen levels were measured in the flue gas. In particular, there was no measurable increase in stack opacity and ACI did not impact the performance of the ESP during the long-term test.

Great River Energy's Stanton Station Unit 10

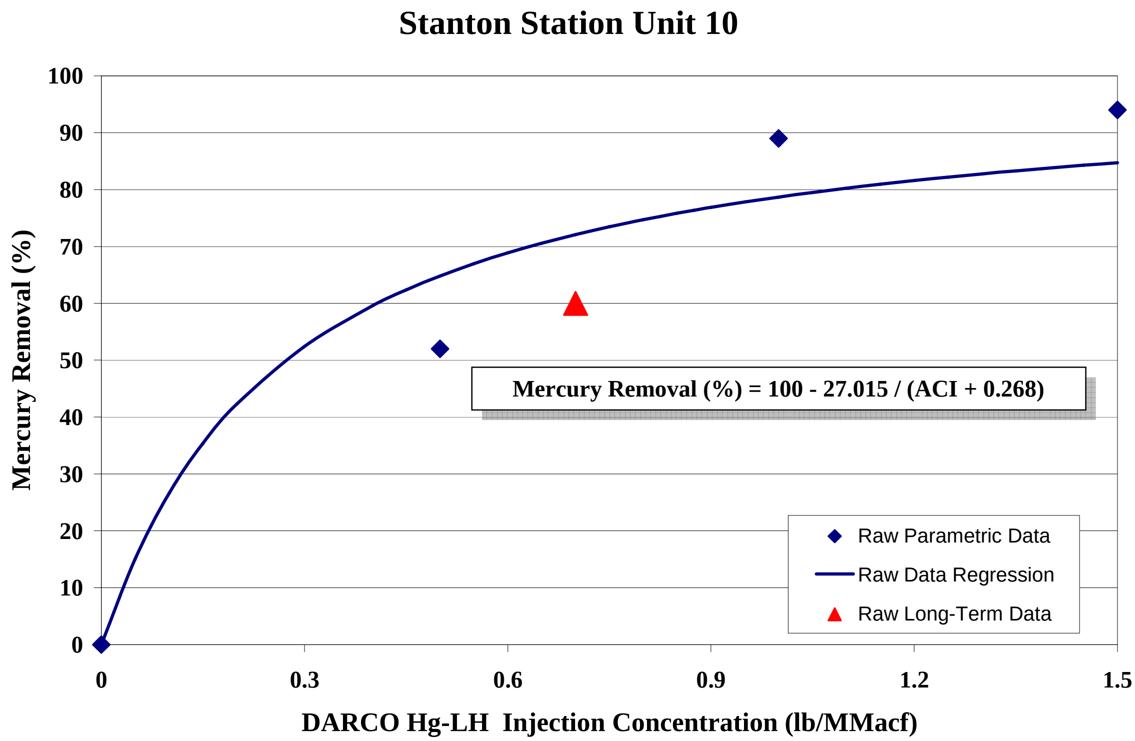
Full-scale field testing was conducted at the ND lignite-fired unit equipped with a SDA/FF configuration as part of the Phase II-1 project entitled *Enhancing Carbon Reactivity for Mercury Control in Lignite-Fired Systems*. Parametric tests were devoted to the evaluation of several PACs. Based on the performance observed during these short-term injection trials, DARCO® Hg-LH was selected for continuous injection during the 30-day long-term test. Testing was completed in July 2004. Some particulars of the test site are provided in the following graphic.

Great River Energy's Stanton Station 10

- 60 MW boiler
- Particulate Control
  - Fabric Filter
- Sulfur Control
  - Spray Dryer Absorber
- North Dakota Lignite Coal
  - 6,613 Btu/lb
  - 0.71% S
  - 0.055 ppm Hg
  - <30 ppm Cl
- SDA Inlet Temperature: 300°F

Baseline mercury removal across the SDA/FF configuration was less than 10%. Total vapor-phase mercury concentrations ranged from 7.5-13 µg/dncm at both the SDA inlet and FF outlet with less than 10% oxidized mercury. The following PACs were evaluated during the parametric testing campaign: (1) DARCO® Hg; (2) NORIT's chemically-treated DARCO® E1; (3) DARCO® Hg-LH; (4) B-PAC™; (5) Barnebey Sutcliffe's super-activated 208CP™; and (6) Barnebey Sutcliffe's iodated CB 200xF™. A DARCO® Hg injection concentration of 6 lb/MMacf was required to achieve 75% mercury removal across the SDA/FF configuration. Mercury removal was limited to 63% with an iodated 200xF™ sorbent injection concentration of 1.7 lb/MMacf. DARCO® E1 was able to achieve 89% mercury removal at an injection concentration of 2 lb/MMacf, while total mercury removal was limited to 58% with a super-activated 208CP™ injection concentration of 1.5 lb/MMacf. Meanwhile, DARCO® Hg-LH and B-PAC™ were able to achieve approximately 95% mercury removal at an injection concentration of 1.5 lb/MMacf.

The following figure displays the performance of DARCO® Hg-LH during parametric and long-term tests. Note the baseline mercury removal during the parametric testing campaign was essentially zero. The diamond symbols represent the results obtained during short-term parametric tests. The red triangle represents the average mercury capture efficiency of DARCO® Hg-LH during long-term testing where mercury removal ranging from 45-80% (60% average) was observed at an average injection concentration of 0.7 lb/MMacf. Also shown on the figures is a least squares curve-fit of the parametric data as a function of DARCO® Hg-LH injection concentration.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the DARCO® Hg-LH injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 27.015
b = 0.268

Over the course of the long-term test, the cleaning frequency of the FF baghouse increased to every three to four hours, as compared to six to eight hours under baseline conditions. However, the contribution of continuous ACI to the increased cleaning cycle cannot be quantified, because the slurry feed to the SDA, which can affect the baghouse cleaning frequency, was not held constant due to coal sulfur variations. In fact, ACI at a concentration of 1 lb/MMacf is estimated to cause only a 0.2% increase in particulate loading. In addition, a 4–6% increase in opacity was observed for a short time (< 5 minutes) immediately after each baghouse cleaning cycle.

DTE Energy's St. Clair Station Unit 1

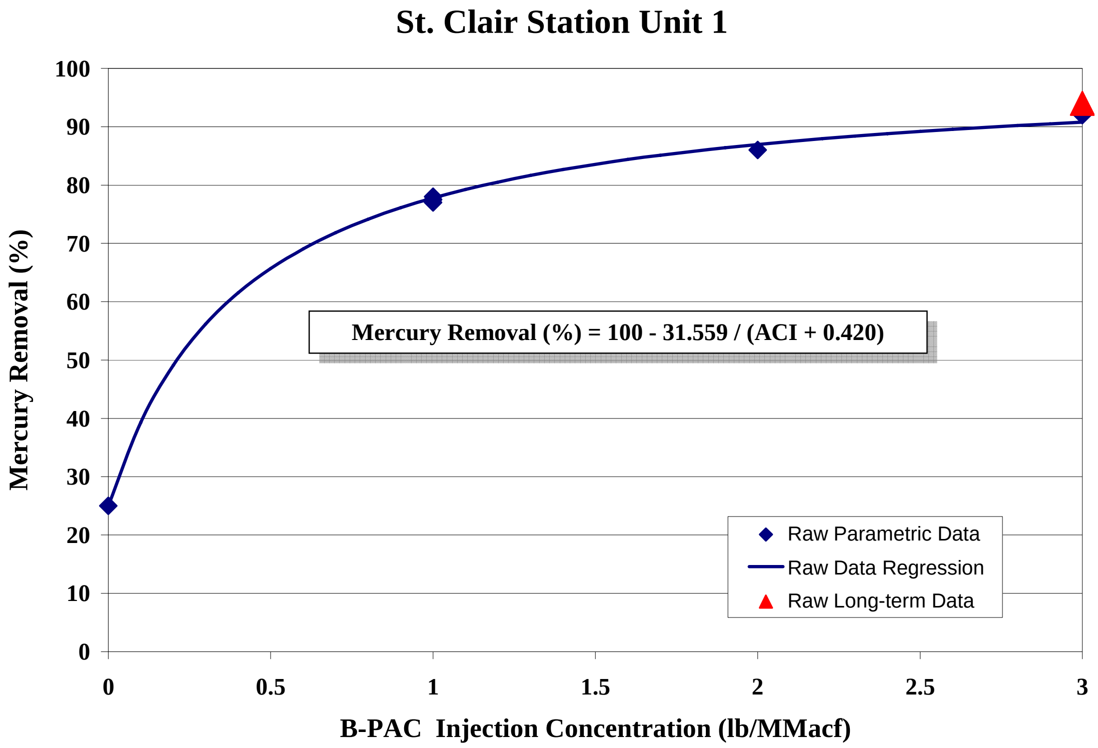
Full-scale field testing was conducted at this site, which typically burns a blend of 85% PRB and 15% eastern bituminous coal and is equipped with a CS-ESP as part of the Phase II-1 project entitled *Advanced Utility Mercury Sorbent Field-Testing Program*. The primary focus of parametric testing as well as the 30-day long-term test was to evaluate the mercury capture efficiency of Sorbent Technologies' brominated B-PAC™. Testing was completed in October 2004. Some particulars of the test site are provided in the following graphic.

DTE Energy's St. Clair Station Unit 1

- 145 MW boiler
- Particulate Control
  - Cold-side ESP, SCA=467 ft^2/1000 acfm
- 85% PRB / 15% Bituminous Coal Blend
  - 9,717 Btu/lb
  - 0.6% S
  - 0.055 ppm Hg
  - 116 ppm Cl
- ESP Inlet Temperature: 290°F

Under baseline conditions, approximately 80% of the total mercury entering the CS-ESP was elemental resulting in 0-40% co-benefit mercury removal. However, baseline mercury removal was approximately 25% prior to the parametric testing campaign. Mercury removal was limited to approximately 70% with DARCO® Hg injection concentrations ranging from 6 to 12 lb/MMacf. Meanwhile, B-PAC™ injection concentrations of 1 lb/MMacf and 3 lb/MMacf were required to achieve total mercury removals of approximately 78% and 93%, respectively.

The following figure displays the performance of B-PAC™ during parametric and long-term tests. The diamond symbols represent the results obtained during short-term parametric tests where the baseline mercury removal was approximately 25%. The red triangle represents the results obtained during the 30-day long-term test where an average mercury removal of 94% was observed at an average B-PAC™ injection concentration of 3 lb/MMacf. Also shown on the figure is a least squares curve-fit of the parametric data as a function of B-PAC™ injection concentration.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the B-PAC™ injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 31.559
b = 0.420

During the long-term continuous injection trial that took place between September 24, 2004 and October 24, 2004, two strategies for potentially reducing the cost of mercury control were investigated. The first test involved switching to a lower-cost version of B-PAC™ that contains less bromine. The low-cost B-PAC™ was injected continuously for approximately 10 hours on October 11, and for about 13 hours on October 23. Total mercury removal on these two days remained constant at approximately 91-92% despite the switch to the lower-cost version of B-PAC™. Another test was conducted where the ACI system was switched on and off every minute for a period of 64 minutes. The intermittent operation of the ACI system effectively reduced the B-PAC™ injection concentration from 3 lb/MMacf to 1.5 lb/MMacf resulting in an average mercury removal of 81%. Conversely, 92% mercury removal was observed before and after this test with a B-PAC™ injection concentration of 3 lb/MMacf.

No adverse balance of plant impacts were observed during continuous B-PAC™ injection at St. Clair. In particular, there was no increase in stack opacity, no brominated PAC-related corrosion issues were identified, the HBr content of the flue gas was minimal, and the performance of the CS-ESP was not impaired.

DTE Energy’s Monroe Station Unit 4

As part of the Phase II-1 project entitled *Evaluation of Sorbent Injection for Mercury Control*, full-scale field testing was conducted at this unit that typically burns a blend of 60% PRB and 40% eastern bituminous coal and is equipped with a sulfur trioxide (SO_3) flue gas conditioning (FGC) system to modify the fly ash resistivity and improve CS-ESP performance. The unit also operates a selective catalytic reduction (SCR) system for nitrogen oxides (NOx) control during the ozone season (May 1 – September 30). Several mercury control technologies were investigated at Monroe, including: (1) coal blending; (2) conventional ACI; (3) brominated (or chemically-treated) ACI; and (4) non-carbon sorbent injection. However, the economics are based on mercury control via DARCO® Hg injection (SCR in-service) since this PAC was evaluated during the 30-day long-term test. Field testing was completed in July 2005. Some particulars of the test site are provided in the following graphic.

DTE Energy’s Monroe Station Unit 4

- 785 MW boiler
- NOx Control
  - SCR System (Ozone season)
- Particulate Control
  - CS-ESP, SCA=285 ft^2/1000 acfm
  - SO_3 flue gas conditioning
- 60% PRB / 40% Bituminous Coal Blend
  - 10,019 Btu/lb
  - 0.57% S
  - 0.056 ppm Hg
  - 556 ppm Cl
- ESP Inlet Temperature: 270°F

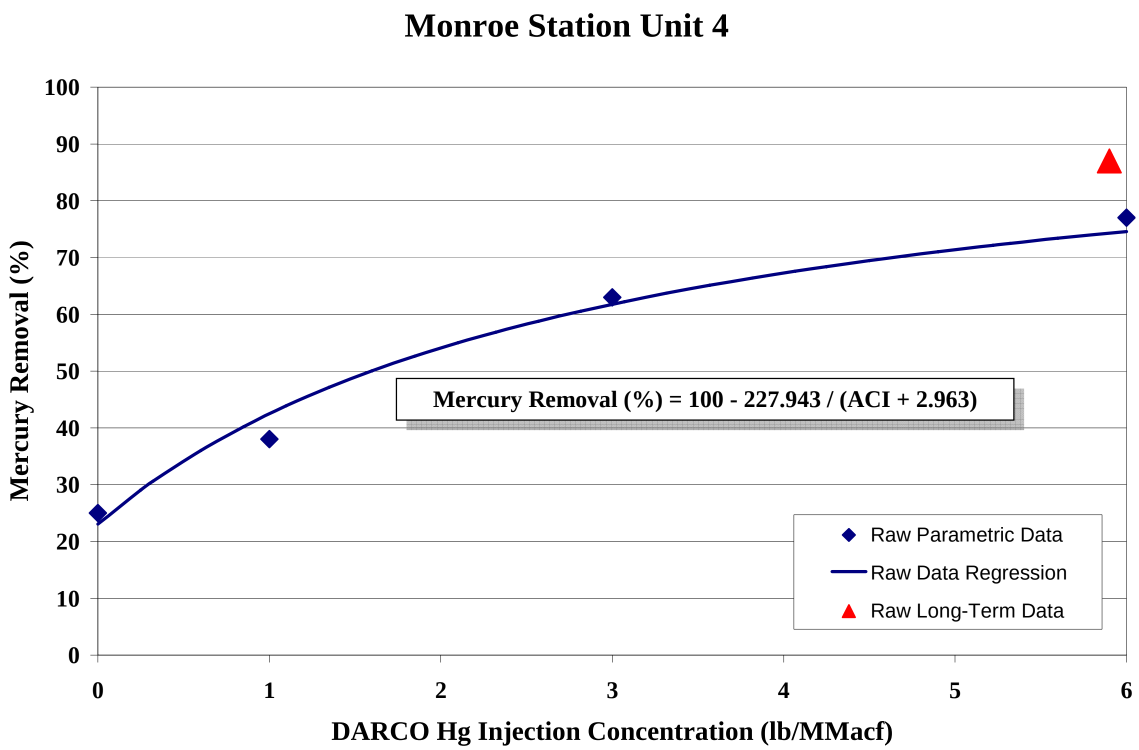
SCR Offline (March 2005)

Baseline mercury capture across the CS-ESP was less than 35% with 20 to 40% elemental mercury in the flue gas. No significant changes in mercury speciation or capture were noted as the coal blend ratio was varied from 60:40 PRB/bituminous to 70:30 PRB/bituminous. During parametric testing, Monroe fired a coal blend consisting of 65% PRB, 20% mid-sulfur bituminous, and 15% low-sulfur bituminous. Results indicate that conventional DARCO® Hg and brominated DARCO® Hg-LH performed similarly with the SCR in bypass. Approximately 90% total mercury capture was achieved with a DARCO® Hg injection concentration of 6 lb/MMacf.

SCR In-Service (May – July 2005)

The fraction of elemental mercury in the flue gas dropped below 10% with the SCR in-service indicating that SCR operation promoted flue gas mercury oxidation. However, baseline mercury capture was slightly lower with the SCR in-service, possibly due to a reduced coal chlorine content during this test period. Average baseline mercury capture was approximately 25% prior to the parametric tests with SCR in-service. During the second round of parametric testing, Monroe fired a coal blend consisting of 65% PRB and 35% mid-sulfur bituminous. At an injection concentration of 3 lb/MMacf, approximately 60% total mercury capture was achieved with DARCO® Hg, DARCO® Hg-LH, and the lower-cost DARCO® XTR. The performance of DARCO® XTR was inferior to that of DARCO® Hg at an injection concentration of 6 lb/MMacf, while DARCO® Hg-LH was not evaluated at this higher injection rate due to a tube leak. Meanwhile, the non-carbon sorbent, NEST, achieved only 10% mercury removal at an injection concentration of 5 lb/MMacf.

The following figure displays the mercury capture efficiency of DARCO® Hg with the SCR in-service. The diamond symbols represent the raw parametric data. For example, 77% total mercury removal was observed at a DARCO® Hg injection concentration of 6 lb/MMacf. Also shown on the figure is a least squares fit of mercury control performance as a function of DARCO® Hg injection concentration, and the unadjusted long-term data. During the long-term continuous injection trial, DARCO® Hg was injected upstream of the CS-ESP from June 1 through July 1, 2005 with the SCR in-service. Total mercury capture averaged 87% with an average DARCO® Hg injection concentration of 5.9 lb/MMacf during the long-term test. The average long-term performance of DARCO® Hg is represented by the red triangle shown below.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the DARCO® Hg injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 227.943
b = 2.963

No adverse balance-of-plant impacts were observed during the long-term test. In particular, DARCO® Hg injection did not impact: (1) CS-ESP spark rate; (2) CS-ESP power requirements; (3) stack opacity; and (4) particulate emissions. Meanwhile, tests on the fly ash/DARCO® Hg mixture collected during long-term testing indicated that less than 0.2% of the mercury collected in the ash samples leached over a 30-day period. In fact, both leaching and thermal desorption results indicated that mercury was more stable on Monroe ash containing DARCO® Hg than ash without DARCO® Hg.

Progress Energy's Lee Station Unit 1

Full-scale field testing was conducted at this low-sulfur eastern bituminous-fired unit that is equipped with an SO_3 FGC system upstream of the air preheater to modify the fly ash resistivity and improve CS-ESP performance as part of the Phase II-2 project entitled *Brominated Sorbents for Cold-Side ESPs, Hot-Side ESPs, and Fly Ash Use in Concrete*. The primary focus of parametric and long-term testing was to evaluate the mercury capture efficiency of Sorbent Technologies' brominated B-PAC™. Testing was completed in April 2006. Some particulars of the test site are provided below.

Progress Energy's Lee Station Unit 1

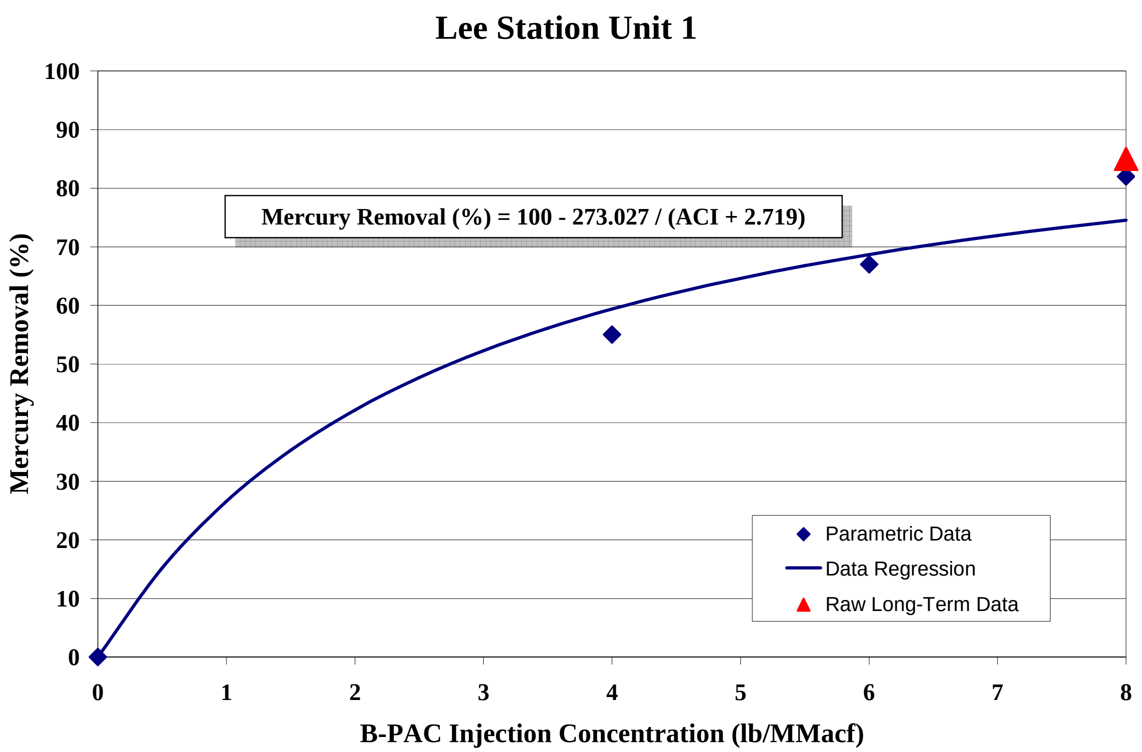
- 79 MW boiler
- Particulate Control
  - Cold-side ESP, SCA=330 ft^2/1000 acfm
  - SO_3 flue gas conditioning
- Eastern Bituminous
  - 12,250 Btu/lb
  - 0.78% S
  - 0.041 ppm Hg
  - 1500 ppm Cl
- ESP Inlet Temperature: 300^{o}F

Under baseline conditions, less than 20% of the total mercury entering the CS-ESP was elemental. Baseline mercury removal generally ranged from 20 to 30% and was approximately 21% prior to the parametric and 30-day long-term field tests.

Parametric testing evaluated the impacts of ACI location and SO_3 conditioning on the mercury capture efficiency of brominated PAC injection by injecting sorbents in three configurations: (1) B-PAC™ injection upstream of the CS-ESP (cold-side injection) with SO_3 conditioning turned on; (2) H-PAC™ injection upstream of the air preheater (hot-side injection) with downstream SO_3 conditioning turned on; and (3) B-PAC™ injection upstream of the CS-ESP (cold-side injection) without SO_3 conditioning. Results indicate that a B-PAC™ (or H-PAC™) injection concentration of 8 lb/MMacf is required to achieve 32, 57 and 81% incremental mercury removal when operating under these three conditions, respectively. This testing clearly shows the impact of flue gas SO_3 on the mercury capture efficiency of brominated PAC injection. In the two conditions where SO_3 injection occurred, the ACI location played a key role. For instance, hot-side H-

PAC™ injection upstream of the SO_3 injection point allowed for additional mercury capture presumably because in-flight mercury capture took place prior to SO_3 interference. Based on these results, the 30-day long-term field test was conducted with cold-side B-PAC™ injection without SO_3 conditioning.

The following figure displays the performance of cold-side B-PAC™ injection during parametric and long-term tests without SO_3 conditioning. The diamond symbols represent the results obtained during short-term parametric tests. Note that Sorbent Technologies adjusted the parametric data to account for the baseline mercury removal observed prior to parametric testing. The red triangle represents the unadjusted results obtained during the 30-day long-term test where an average total mercury removal of 85% was observed at an average B-PAC™ injection concentration of 8 lb/MMacf. Also shown on the figure is a least squares curve-fit of the adjusted parametric data as a function of B-PAC™ injection concentration.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the B-PAC™ injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

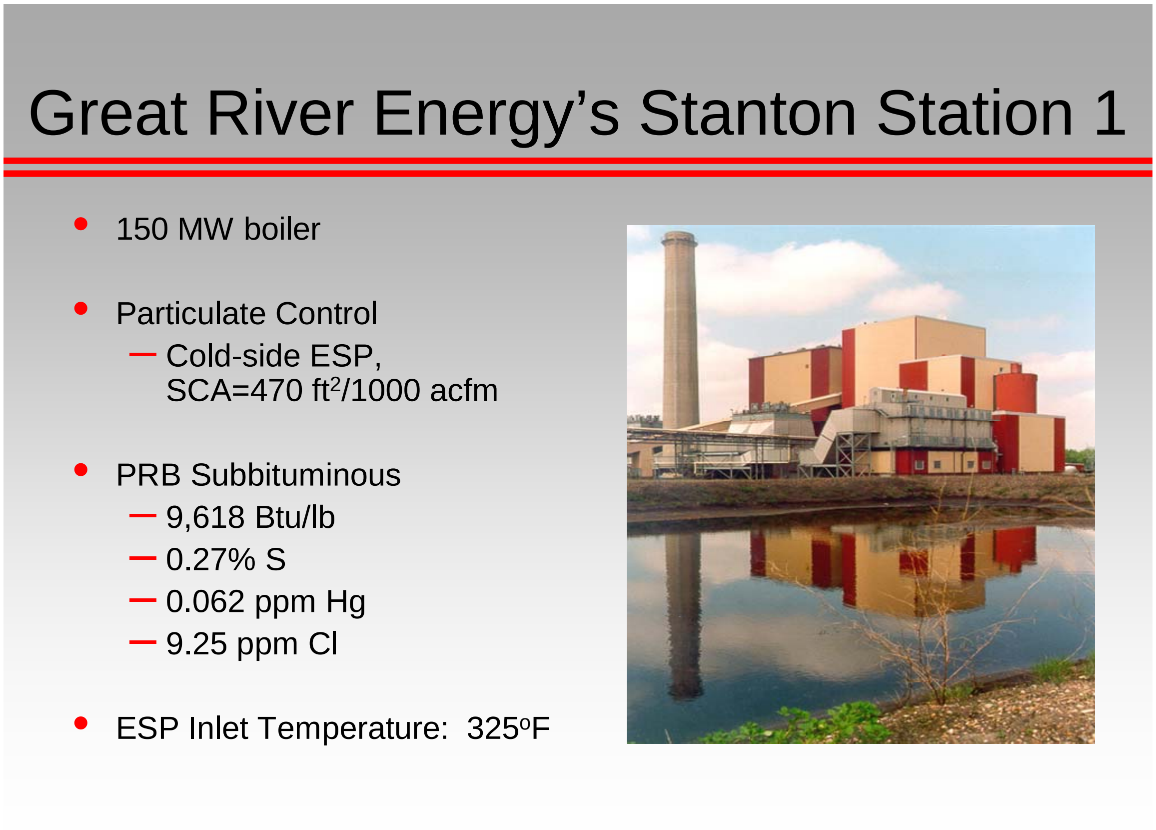
Where a = 273.027
b = 2.719

No adverse balance of plant impacts were observed during continuous B-PAC™ injection at Lee Unit 1. In fact, preliminary results appear to indicate a "co-benefit" of reduced opacity with continuous B-PAC™ injection since the unit was able to operate without

SO_3 FGC during the 30-day long-term test without exceeding plant opacity limits. Following the long-term B-PAC™ trial, opacity levels continually increased until the SO_3 FGC system was re-activated about one day later. In addition, analysis of corrosion coupons (inserted downstream of the air preheater) indicates that corrosion loss per day has higher during the baseline period than during continuous B-PAC™ injection. The disparity is most likely due to SO_3 since the FGC system was operational during baseline testing, but turned off during the long-term B-PAC™ injection test.

Great River Energy's Stanton Station Unit 1

Full-scale field testing was conducted at this PRB-fired unit equipped with a CS-ESP as part of the Phase II-1 project entitled *Enhancing Carbon Reactivity for Mercury Control in Lignite-Fired Systems*. Parametric tests were devoted to the evaluation of several chemically-treated sorbents. Based on the performance observed during these short-term injection trials, B-PAC™ was selected for continuous injection during the 30-day long-term test. Testing was completed in October 2005. Some particulars of the test site are provided in the following graphic.

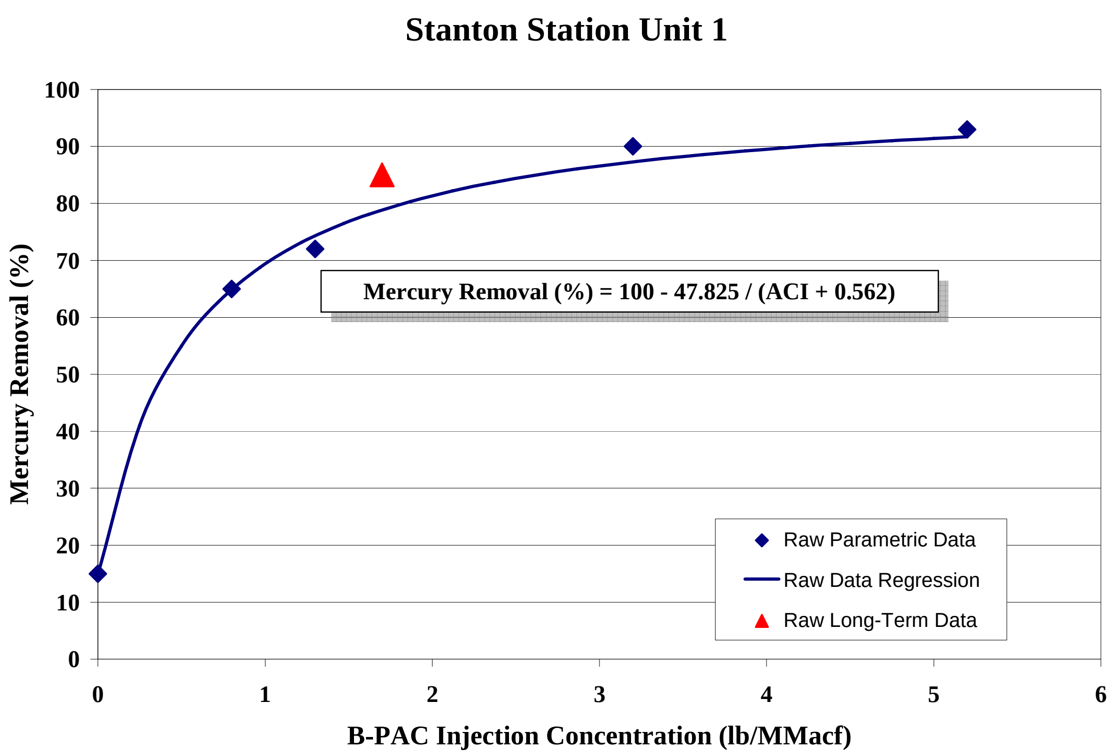


During baseline testing, the flue gas contained very little oxidized mercury and removal across the CS-ESP generally ranged from 10 to 25%. Short-term parametric tests were conducted in two phases. In July 2005, five sorbents were evaluated: (1) DARCO® Hg; (2) DARCO® Hg-LH; (3) B-PAC™; (4) B-PAC™-LC1 (lower cost); and (5) Calgon Carbon's iodated HGR-LH sorbent. The brominated B-PAC™ and DARCO® Hg-LH sorbents achieved 90% total mercury removal at injection concentrations of 3.2 and about 5.5 lb/MMacf, respectively. Approximately 85% total mercury removal was observed with a B-PAC™-LC1 injection concentration of 3.8 lb/MMacf. Mercury removal was limited to about 50% with DARCO® Hg injection concentrations ranging from 3 to over 7 lb/MMacf. Similar results were observed during HGR-LH sorbent injection. Based on these results, brominated B-PAC™ was selected for evaluation during the 30-day long-term field test.

Following long-term testing, a second round of parametric testing was conducted in October 2005 with two additional sorbents: Ningxia Huahui's iodated carbon (NH

Carbon), and B-PAC™-LC2. Baseline mercury removal ranged from 35 to 50% prior to these tests. The increase in native mercury capture was likely caused by residual B-PAC™ remaining in the ductwork from the long-term testing period. The NH Carbon achieved 76% total mercury removal at an injection concentration of 3.4 lb/MMacf, while 68% total mercury removal was demonstrated with a B-PAC™-LC2 injection concentration of 4.8 lb/MMacf.

The following figure displays the performance of B-PAC™ during parametric and long-term tests. The diamond symbols represent the results obtained during short-term parametric tests. The red triangle represents the average long-term results where 85% total mercury removal was demonstrated at an average B-PAC™ injection concentration of 1.7 lb/MMacf. Also shown on the figures is a least squares curve-fit of the parametric data as a function of B-PAC™ injection concentration.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the B-PAC™ injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

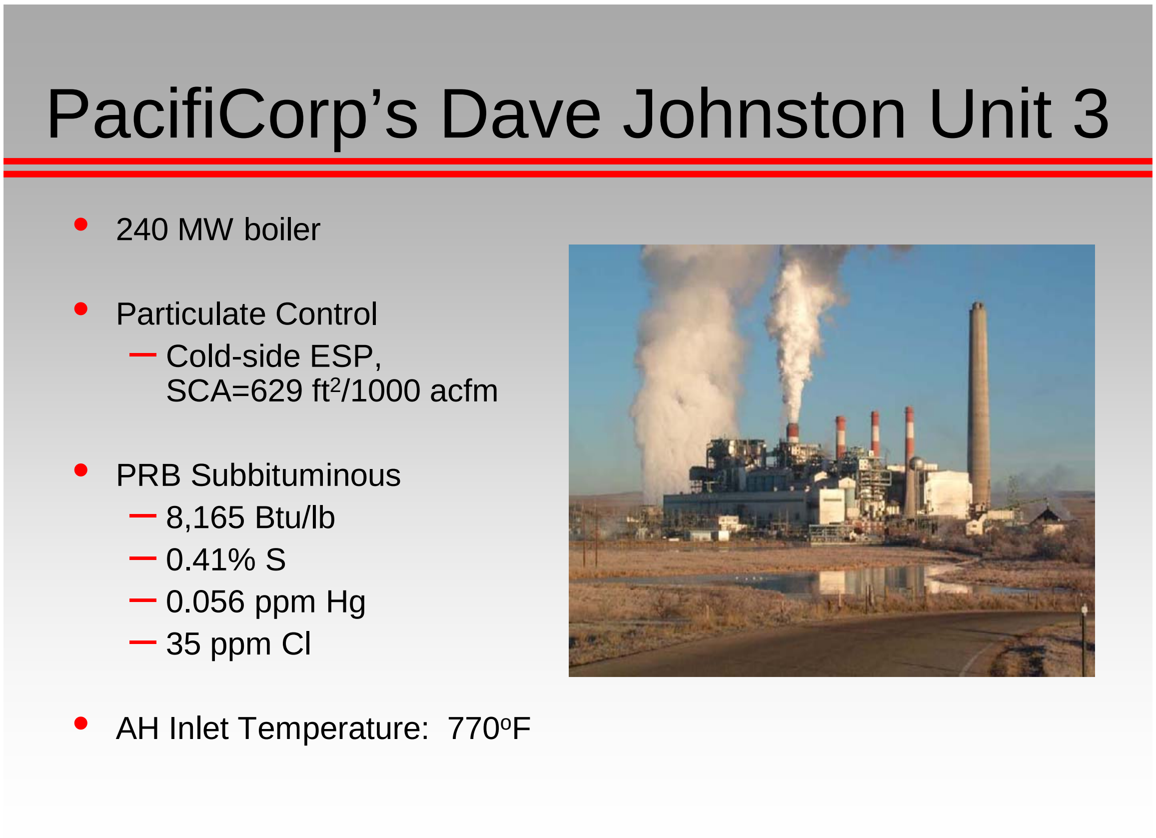
Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 47.825
b = 0.562

Plant operation parameters were not measurably affected by continuous B-PAC™ injection over the 30-day long-term test. In particular, B-PAC™ injection had little to no effect on ESP operation, particulate emissions, and opacity measurements. While no problems with ESP performance were noticed during the long-term B-PAC™ injection test, these observations cannot be extrapolated to interpret how sustained injection over the lifetime of an ESP would affect its mechanical integrity.

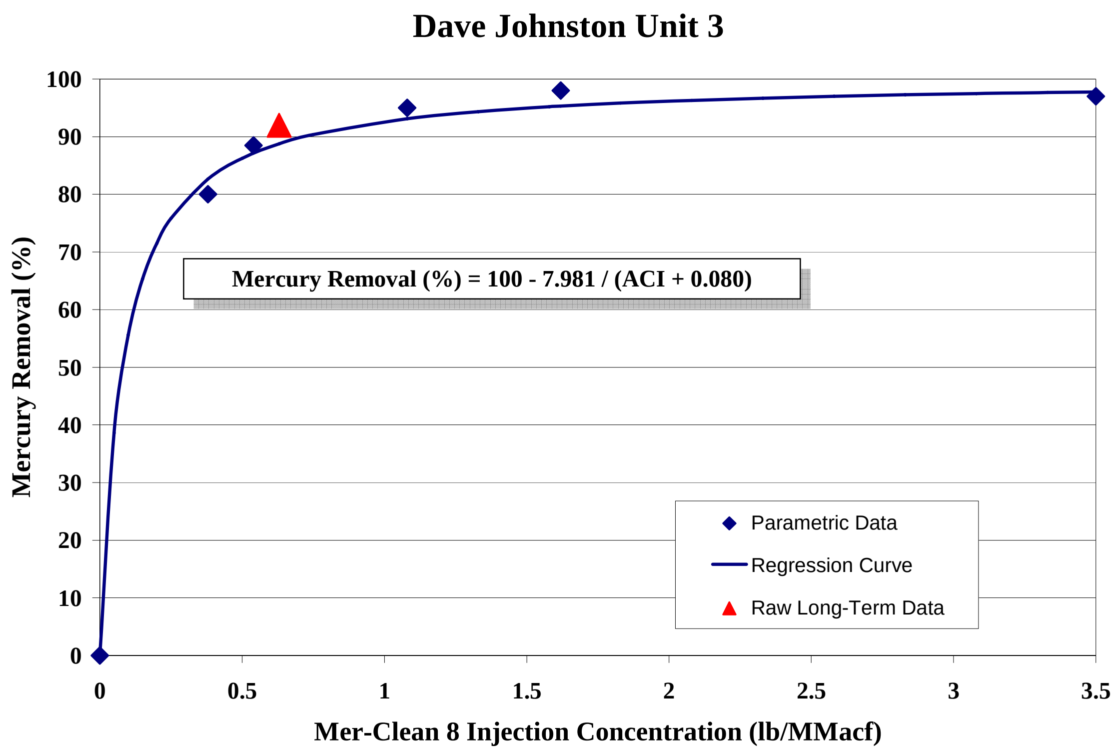
PacifiCorp's Dave Johnston Unit 3

Full-scale field testing was conducted at this PRB-fired unit equipped with a CS-ESP as part of the Phase II-2 project entitled *Field Demonstration of Enhanced Sorbent Injection for Mercury Control*. Parametric tests were devoted to the evaluation of several chemically-treated Mer-Clean™ sorbents in the Mer-Cure™ system. The Mer-Cure™ process is unique in that chemically-treated sorbent injection takes place in the high-temperature region upstream of the air preheater. Based on the performance observed during these short-term injection trials, the Mer-Clean™ 8 sorbent was selected for continuous injection during the 30-day long-term test. Testing was completed in September 2005. Some particulars of the test site are provided in the following graphic.



During baseline testing, the flue gas contained very little oxidized mercury and removal across the CS-ESP was generally less than 10%. Four Mer-Clean™ sorbents – labeled Mer-Clean™ 2, 4, 6, and 8 – were evaluated during the short-term parametric tests. The Mer-Cure™ technology performed well with each of the Mer-Clean™ sorbents achieving greater than 90% mercury removal at an injection concentration less than 2 lb/MMacf. The Mer-Clean™ 8 sorbent was the high performer, achieving 90% and 98% mercury removal at approximate injection concentrations of 0.6 and 1.6 lb/MMacf, respectively.

The following figure displays the performance of Mer-Clean™ 8 during parametric and long-term tests. The diamond symbols represent the results obtained during short-term parametric tests. Note that ALSTOM adjusted the parametric data to account for the baseline mercury removal observed prior to parametric testing. The red triangle represents the average unadjusted long-term results where 92% total mercury removal was demonstrated at an average Mer-Clean™ 8 injection concentration of 0.63 lb/MMacf. Also shown on the figures is a least squares curve-fit of the parametric data as a function of Mer-Clean™ 8 injection concentration.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the Mer-Clean™ 8 injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

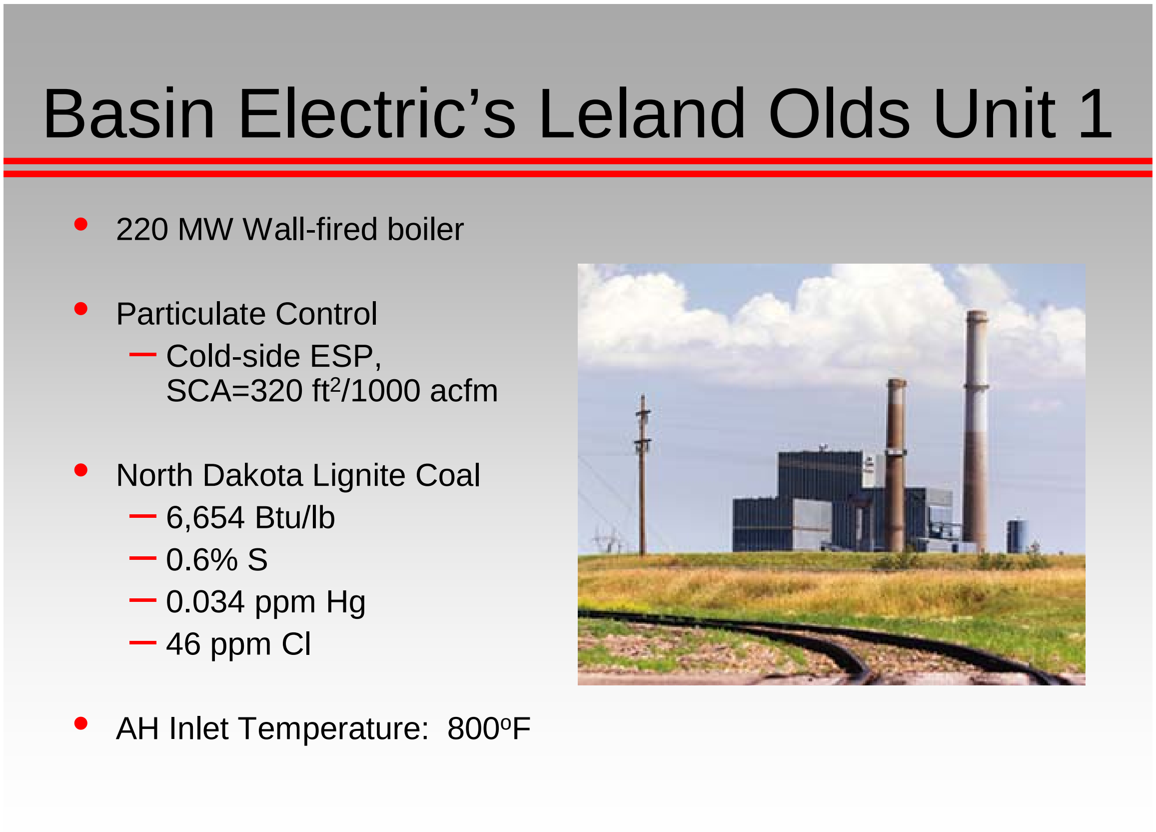
Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 7.981
b = 0.080

Preliminary results indicate that no adverse balance-of-plant impacts were observed during the long-term Mer-Cure™ field test.

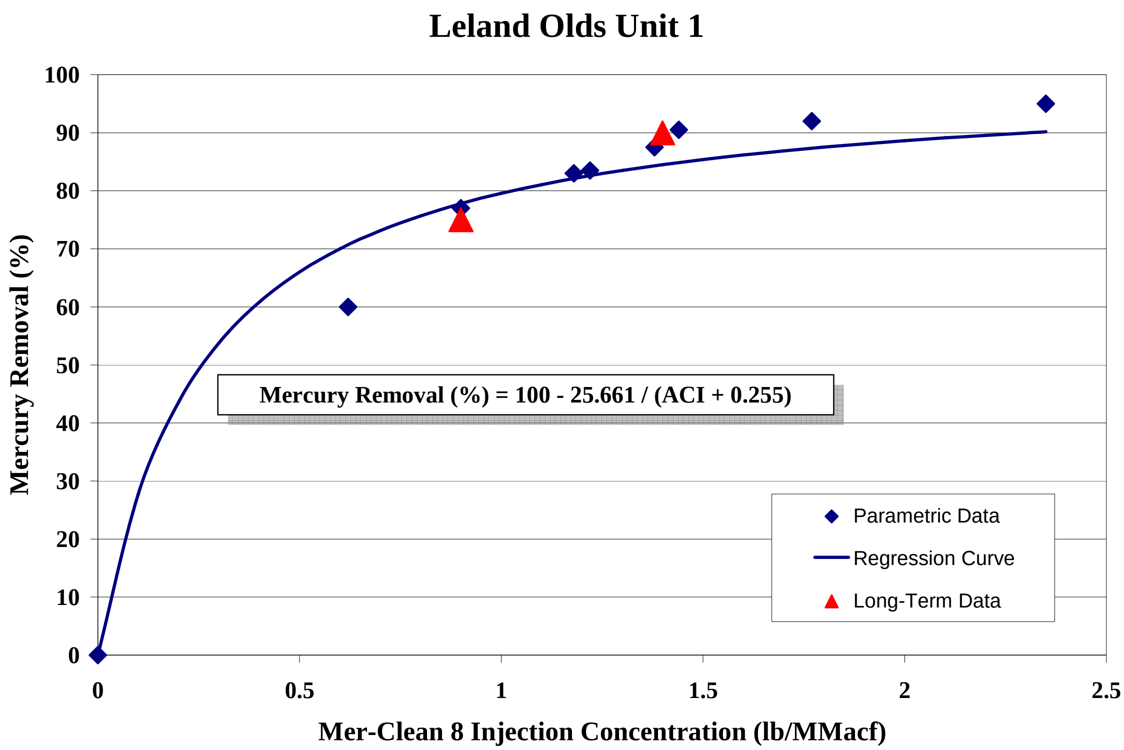
Basin Electric's Leland Olds Station Unit 1

Full-scale field testing was conducted at this ND lignite-fired unit equipped with a CS-ESP as part of the Phase II-2 project entitled *Field Demonstration of Enhanced Sorbent Injection for Mercury Control*. Parametric tests were devoted to the evaluation of several chemically-treated Mer-Clean™ sorbents in the Mer-Cure™ system. Based on the performance observed during these short-term injection trials, the Mer-Clean™ 8 sorbent was selected for continuous injection during the 30-day long-term test. Testing was completed in November 2005. Some particulars of the test site are provided in the following graphic.



Approximately 80% of the total gaseous mercury was elemental during baseline testing, and removal across the CS-ESP was generally less than 10%. Four Mer-Clean™ sorbents – labeled Mer-Clean™ 2, 4, 6, and 8 – were evaluated during the short-term parametric tests. Mercury removal was limited to 50% with a Mer-Clean™ 6 injection concentration of about 2.9 lb/MMacf. The Mer-Clean™ 2 and 4 sorbents performed similarly, achieving at least 90% mercury removal at an injection concentration of about 2.9 lb/MMacf. Mer-Clean™ 8 demonstrated the best performance, achieving 90% and 95% mercury removal at estimated injection concentrations of 1.5 and 2.2 lb/MMacf, respectively.

The following figure displays the performance of Mer-Clean™ 8 during parametric and long-term tests. The diamond symbols represent the results obtained during short-term parametric tests. Note that ALSTOM adjusted the parametric data to account for the baseline mercury removal observed prior to parametric testing. The red triangles represent the average unadjusted long-term results. During the initial five days of long-term testing, 75% total mercury removal was achieved with an average Mer-Clean™ 8 injection concentration of 0.9 lb/MMacf. For the remainder of long-term testing, total mercury removal averaged 90% with an average Mer-Clean™ 8 injection concentration of 1.4 lb/MMacf. Also shown on the figures is a least squares curve-fit of the parametric data as a function of Mer-Clean™ 8 injection concentration.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the Mer-Clean™ 8 injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 25.661
b = 0.255

Preliminary results indicate that no adverse balance-of-plant impacts were observed during the long-term Mer-Cure™ field test.

Reliant Energy’s Portland Station Unit 1

Full-scale field testing was conducted at this medium-sulfur eastern bituminous coal-fired unit equipped with a CS-ESP as part of the Phase II-2 project entitled *Field Demonstration of Enhanced Sorbent Injection for Mercury Control*. Parametric tests were devoted to the evaluation of several chemically-treated Mer-Clean™ sorbents in the Mer-Cure™ system. Based on the performance observed during these short-term injection trials, the Mer-Clean™ 8-21 sorbent variation was selected for continuous injection during the long-term test. Testing was completed in June 2006. Some particulars of the test site are provided in the following graphic.

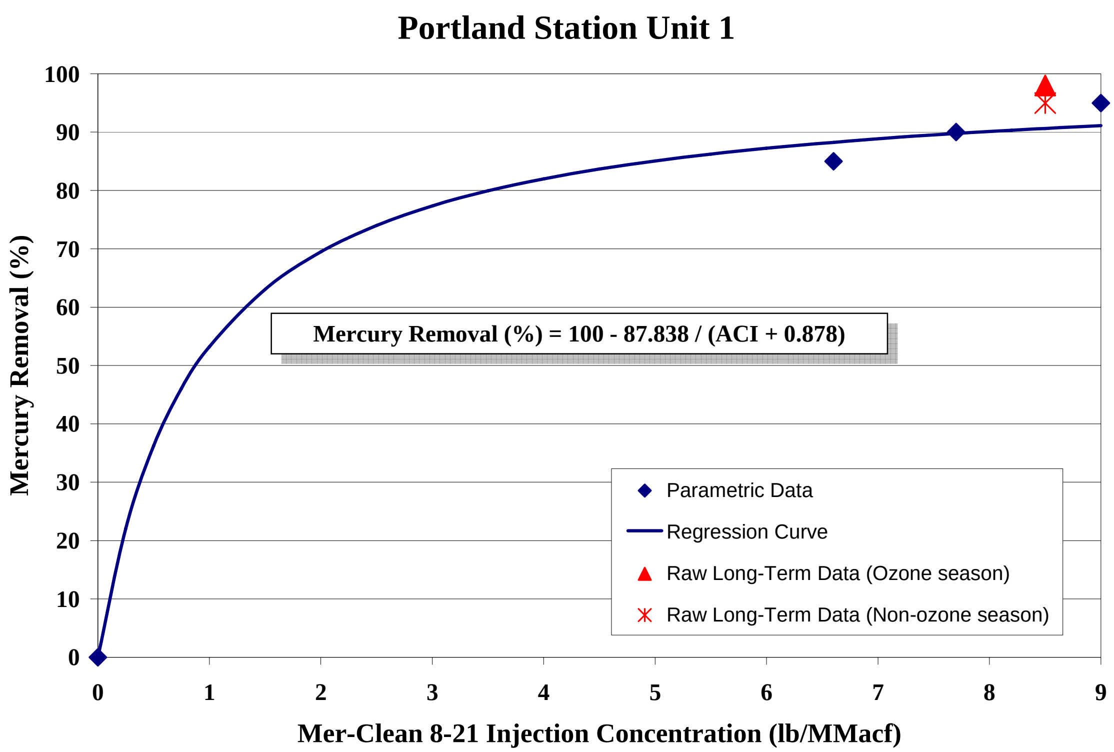
Reliant Energy’s Portland Station Unit 1

- 170 MW boiler
- Particulate Control
  - Cold-side ESP, SCA=284 ft^2/1000 acfm
- Eastern Bituminous
  - 13,002 Btu/lb
  - 1.98% S
  - 0.103 ppm Hg
  - 1144 ppm Cl
- AH Inlet Temperature: 640^{o}F

During baseline testing, no native mercury capture was observed between the boiler and air preheater inlet. Several Mer-Clean™ sorbents – labeled Mer-Clean™ 2, 4, 6, 8, 9, 8-2, 8-4, and 8-21 – were evaluated during the short-term parametric tests completed prior to ozone season. At an injection concentration of 6.6 lb/MMacf, mercury removal generally ranged from 72 to 85% with most of the Mer-Clean™ sorbents, although removal was limited to about 53% with the Mer-Clean™ 6 sorbent. The Mer-Clean™ 8-21 sorbent demonstrated the best performance, achieving 90% and 95% mercury removal at estimated injection concentrations of 7.7 and 9 lb/MMacf, respectively. These are higher Mer-Clean™ sorbent injection rates than were required at Dave Johnston and Leland Olds, which is believed to be due to elevated levels of SO_3 in the flue gas. The combustion of medium-sulfur eastern bituminous coal leads to higher levels of SO_3, which competes with the mercury for bonding sites on the Mer-Clean™ sorbent surface.

During ozone season (May 1 – September 30), the boiler at Portland Station Unit 1 is operated with deeper air staging to further reduce NOx emissions. This boiler modification could also impact mercury speciation and capture due to variations in unburned carbon. To investigate the impact of ozone season operation on mercury control, long-term testing was conducted in two phases, covering both the non-ozone and ozone seasons. Note that baseline mercury removal was approximately 29% prior to long-term testing. During non-ozone season long-term testing, total mercury removal averaged 95% with an average Mer-Clean™ 8-21 injection concentration of 8.5 lb/MMacf. Mercury removal was slightly higher during ozone season. Total mercury removal averaged 98% with an average Mer-Clean™ 8-21 injection concentration of 8.5 lb/MMacf, during ozone season long-term testing.

The following figure displays the performance of Mer-Clean™ 8-21 during parametric and long-term tests. The diamond symbols represent the results obtained during non-ozone season parametric tests. The red triangles represent the average unadjusted long-term results where 95% and 98% total mercury removal was demonstrated at an average Mer-Clean™ 8-21 injection concentration of 8.5 lb/MMacf during the non-ozone and ozone seasons, respectively. Also shown on the figures is a least squares curve-fit of the parametric data as a function of Mer-Clean™ 8-21 injection concentration.



The following non-linear regression equation was used to empirically fit the data. Note that ACI represents the Mer-Clean™ 8-21 injection concentration in lb/MMacf. Details of the regression results are provided in Appendix E of this report.

Mercury Removal (%) = 100 – a / (ACI + b)

Where a = 87.838
b = 0.878

No adverse balance-of-plant impacts were observed during long-term testing. In particular, both stack opacity and particulate matter measurements indicate that Mer-Clean™ sorbent injection did not increase particulate emission levels at the stack.

APPENDIX C

Phase II Data Adjustment Methodology

Phase II Data Adjustment Methodology

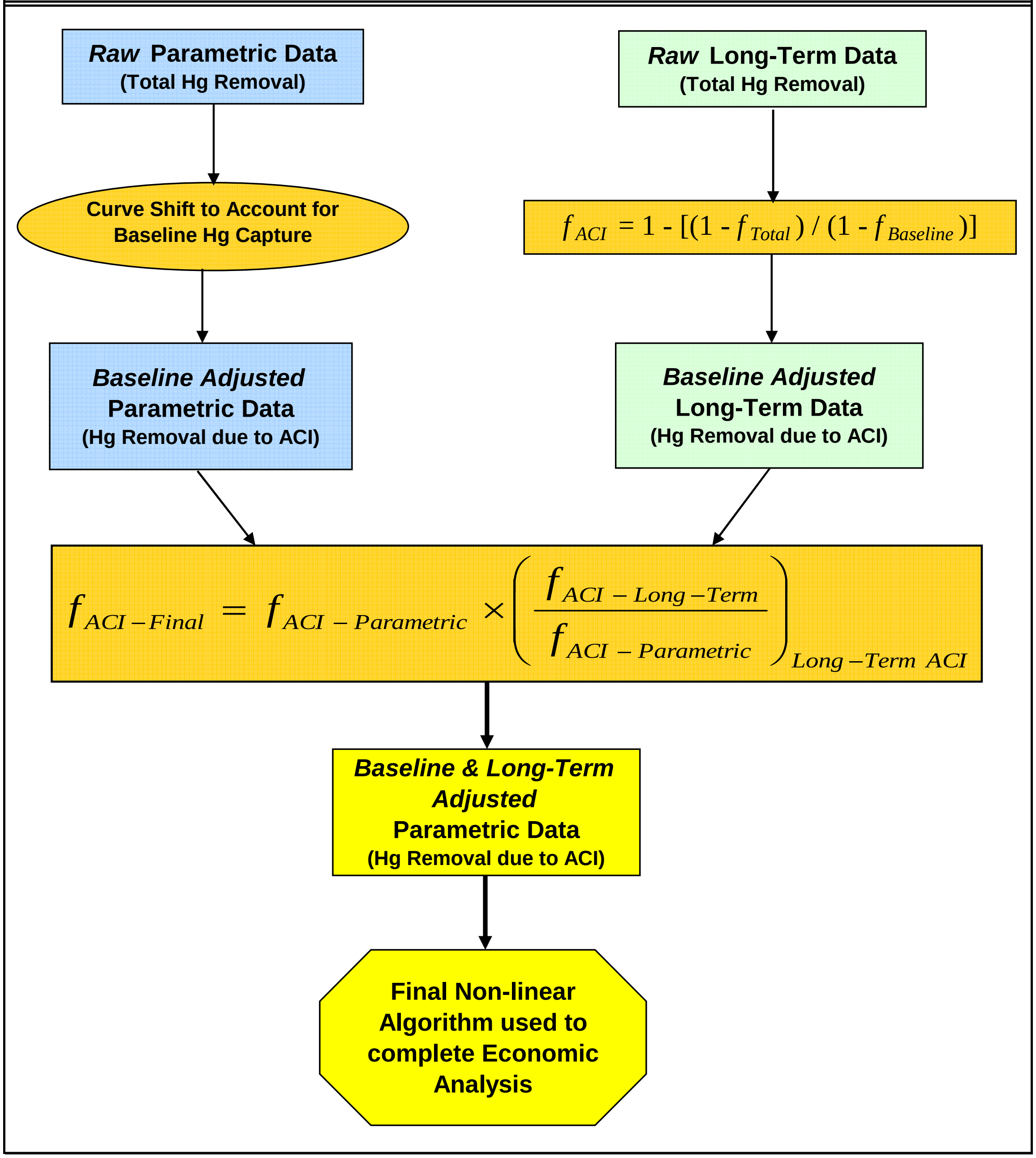
In order to estimate ACI costs, it is necessary to establish a mathematical relationship (algorithm) between ACI concentration and mercury capture performance for each of the DOE/NETL Phase II field test sites.

To calculate the percent mercury removal that is directly attributable to ACI, a methodology was developed to incorporate the baseline, short-term parametric, and long-term field test data. The methodology is comprised of the following steps:

(1) Develop an ACI concentration versus mercury removal non-linear regression algorithm using the short-term parametric field test data;
(2) Shift the ACI performance curve developed in step 1 to account for the baseline mercury capture observed prior to the short-term parametric tests;
(3) Adjust the average total mercury removal achieved during the long-term field test to account for the baseline removal calculated for the average long-term ACI concentration;
(4) Scale the adjusted algorithm developed in step 2 to include the baseline adjusted long-term field test data point developed in step 3; and
(5) Re-calculate the ACI performance algorithm using the baseline and long-term adjusted parametric test data.

It is important to note that the algorithm adjustment used in step 2 assumes that during ACI the effective baseline mercury capture gradually decreases and approaches zero as the ACI concentration increases. This approach is supported by the results of thermal desorption tests conducted at Holcomb Station, which led to the conclusion that during ACI, *there is no "native" mercury capture by the fly ash*; instead, the gaseous mercury is captured by the more reactive activated carbon rather than the fly ash.

Phase II Data Adjustment Methodology



Variables	Definition
f_{ACI}	Fractional Hg removal due to ACI
f_{Total}	Fractional total Hg removal
$f_{Baseline}$	Fractional Hg removal by existing APCDs
$f_{ACI\text{ - }Final}$	Fractional Hg removal due to ACI that accounts for baseline Hg capture and incorporates the average long-term ACI performance
$f_{ACI\text{ - }Parametric}$	Fractional Hg removal due to ACI during short-term parametric tests
$f_{ACI\text{ - }Long\text{-}Term}$	Fractional Hg removal due to ACI during long-term testing
$Long\text{-}Term\ \ ACI$	Average ACI concentration during long-term test

To facilitate a better understanding of the methodology described above, the following section demonstrates how the adjustments were made to the baseline, parametric, and average long-term data collected during Phase II field testing at Holcomb Station Unit 1.

Data Adjustment for Holcomb Station Unit 1

The economic analysis of mercury control is based on the performance of DARCO® Hg-LH during parametric and long-term testing. The results obtained from these full-scale field tests are shown in the following table.

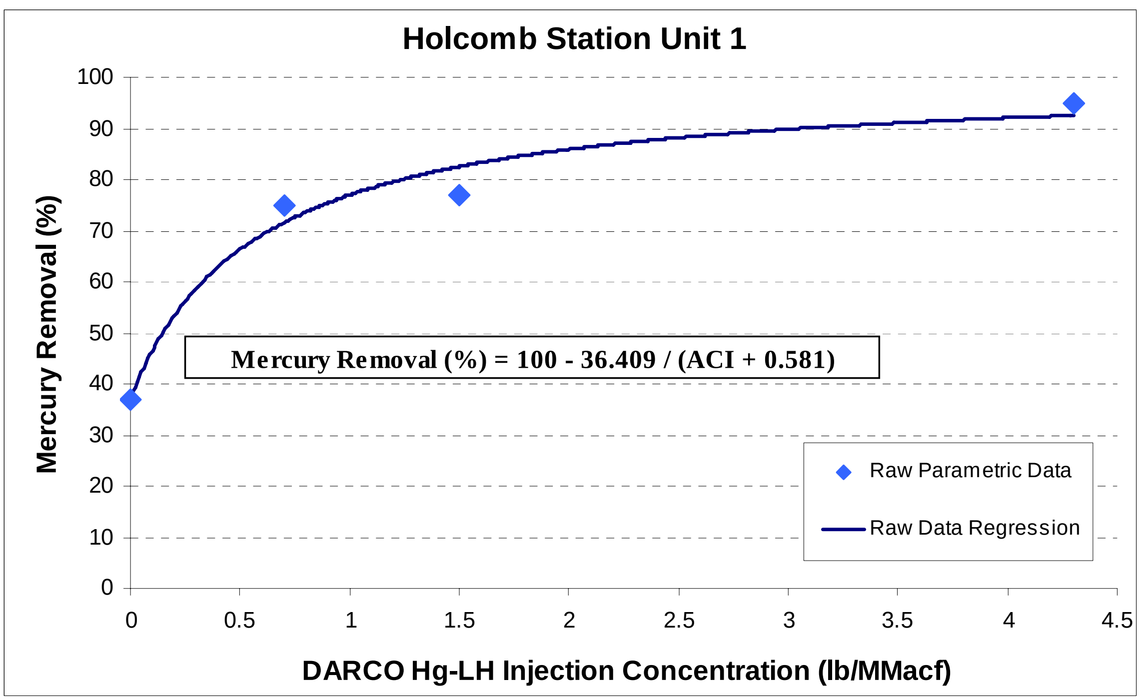
Raw Parametric Data		Average Long-Term Data	
DARCO® Hg-LH, lb/MMacf	Mercury Removal, %	DARCO® Hg-LH, lb/MMacf	Mercury Removal, %
0	37	1.2	93
0.7	75		
1.5	77		
4.3	95		

Step 1

The raw parametric data was used to develop the non-linear algorithm shown below in Figure C-1. Details of the regression results are provided in Appendix E of this report.

$$\%\,Hg\ \mathrm{Re}moval = 100 - \frac{36.409}{ACI + 0.581}$$

Figure C-1 – Parametric ACI Performance Data and Algorithm – Unadjusted



Step 2

The unadjusted parametric performance curve from step 1 was extrapolated to determine the X-axis intercept of the algorithm, which corresponds to a theoretical DARCO® Hg-LH injection concentration of -0.22 lb/MMacf. According to the unadjusted parametric performance curve, a DARCO® Hg-LH injection concentration of 0.22 lb/MMacf would be required to achieve the baseline mercury removal of 37% observed prior to the parametric testing campaign. Therefore, the unadjusted curve was shifted to the right by 0.22 lb/MMacf. The resultant adjusted parametric regression curve displays the level of mercury control that is directly attributable to ACI as a function of DARCO® Hg-LH injection concentration.

This parametric data adjustment assumes that during ACI the effective baseline mercury capture gradually decreases and approaches zero as the ACI concentration increases. To quantify this declining baseline phenomenon, the levels of mercury control predicted by the unadjusted (total mercury removal) and adjusted (mercury capture due to ACI) parametric regression curves were compared to develop a relationship expressing the predicted level of baseline mercury capture as a function of DARCO® Hg-LH injection concentration. The following calculation was repeated over the entire range of ACI concentrations investigated during the parametric testing campaign.

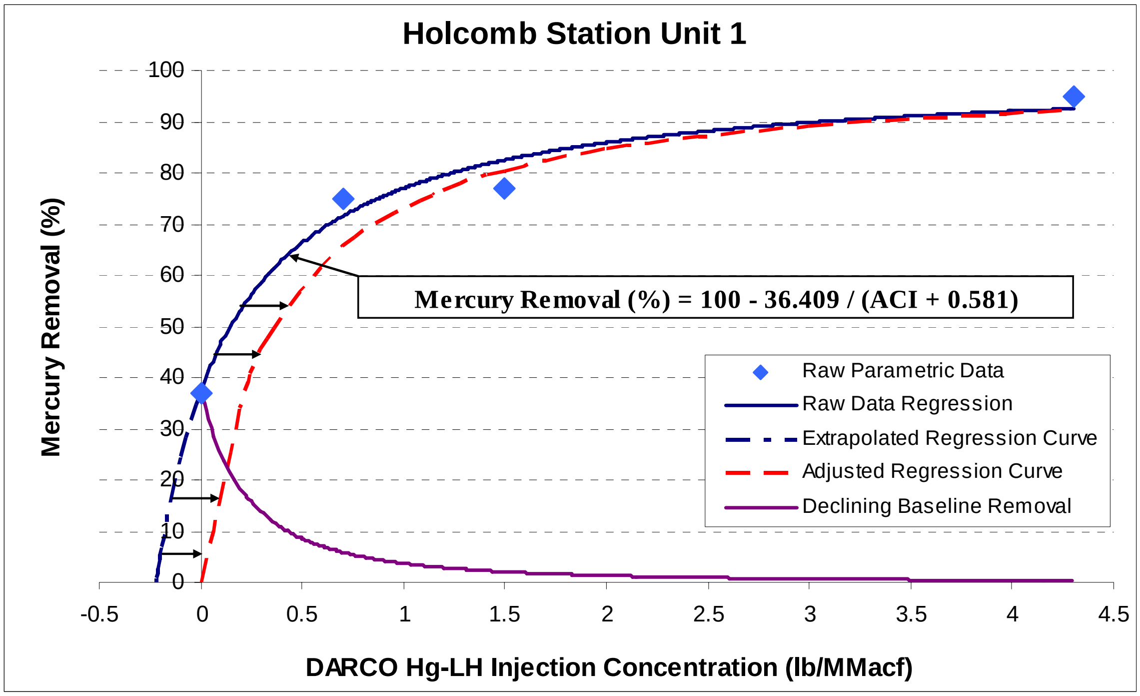
Baseline Hg Removal, % = Total Hg Removal, % – Hg Capture due to ACI, %

Table C-1 provides the non-linear regression results for several DARCO® Hg-LH injection concentrations, the adjusted DARCO® Hg-LH injection concentrations, and the baseline mercury removal calculated for each of the adjusted ACI concentrations. The adjustment made to the parametric performance curve as well as the declining baseline curve are graphically illustrated in Figure C-2.

Table C-1 –Parametric Performance Data - Adjustment for Baseline Removal

Raw Data Regression		Adjustment	Baseline Mercury Removal, %
[DARCO® Hg-LH], lb/MMacf	Mercury Removal, %	[DARCO® Hg-LH], lb/MMacf	
-0.22	0	**0**	37.33
0	37.33	0.22	17.21
0.48	65.68	**0.70**	5.89
0.70	71.58	0.92	4.17
0.98	**76.68**	**1.20**	**2.88**
1.20	79.56	1.42	2.25
1.28	80.44	**1.50**	2.07
1.50	82.50	1.72	1.67
4.08	92.19	**4.30**	0.35
4.30	92.54	4.52	N/A

Figure C-2 – Parametric Data Adjustment and Declining Baseline Mercury Capture



Step 3

During long-term testing at Holcomb, an average total mercury removal of 93% was observed at an average DARCO® Hg-LH injection concentration of 1.2 lb/MMacf. To determine the level of mercury control that is attributable to ACI, the level of baseline mercury capture at an ACI concentration of 1.2 lb/MMacf was calculated as 2.88% by taking the difference between total mercury removal (79.56%) and ACI mercury removal (76.68%) from the unadjusted and adjusted parametric regression curves, respectively. Using 2.88% as the baseline removal, the average level of long-term mercury control that is attributable to ACI was determined using the following equation, where *f* represents fractional mercury removal.

$$f_{ACI} = 1 - \left(\frac{1 - f_{Total}}{1 - f_{Baseline}} \right) = 1 - \left(\frac{1 - 0.93}{1 - 0.0288} \right) = 0.9279 \Rightarrow 92.79\%$$

Step 4

The baseline adjusted parametric regression curve was scaled to include the average level of long-term mercury control that is attributable to ACI as calculated in step 3. This was accomplished by applying the following equation over the entire range of DARCO® Hg-LH injection concentrations investigated during parametric testing.

$$f_{Final} = f_{ACI-Parametric} \times \left(\frac{f_{ACI-Long-Term}}{f_{ACI-Parametric}} \right)_{Long-Term\ ACI}$$

The following sample calculation applies to an ACI concentration of 1.5 lb/MMacf. Note that the adjusted parametric regression curve yields 76.68% mercury removal due to ACI for an injection concentration of 1.2 lb/MMacf.

$$f_{Final} = 80.44\% \times \frac{92.79\%}{76.68\%} = 97.34\%$$

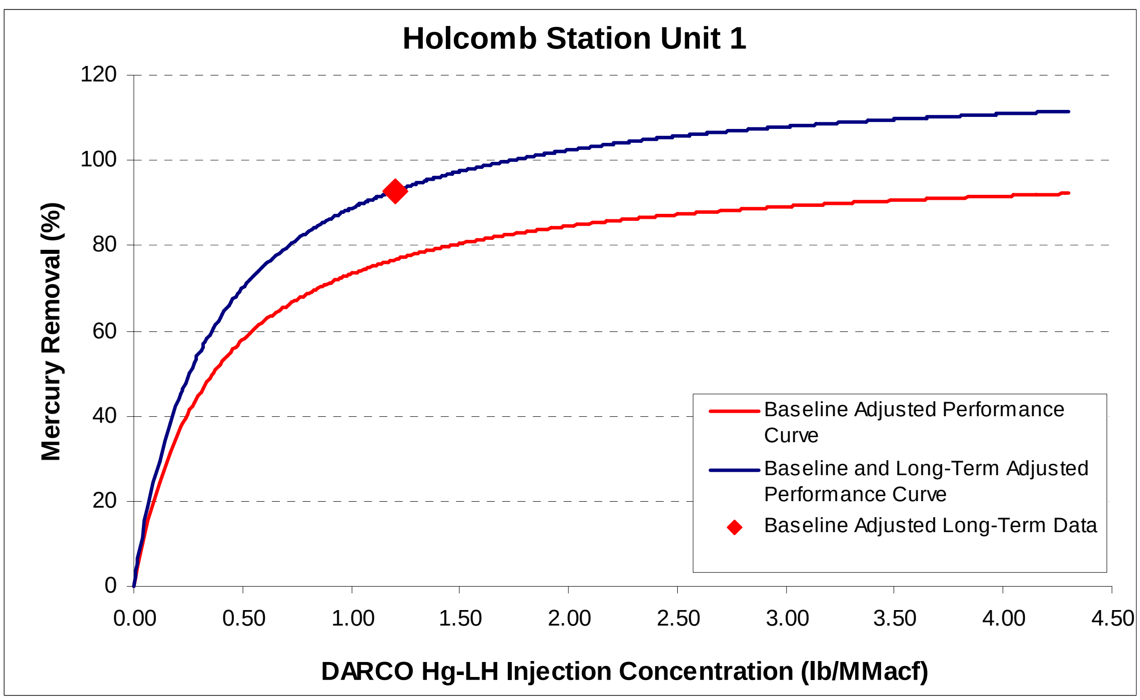
The baseline adjusted parametric data calculated in step 2 as well as the baseline adjusted parametric data that incorporates the average level of long-term mercury control due to the injection of DARCO® Hg-LH are presented in Table C-2.

Table C-2 –Parametric Performance Data - Adjustment for Long-Term Data

	Parametric Performance Data – Adjusted for Baseline	Parametric Performance Data – Adjusted for Baseline and Long-Term Data
[DARCO® Hg-LH], lb/MMacf	Mercury Removal due to ACI, %	Mercury Removal due to ACI, %
0.0	0.00	0.00
0.7	65.68	79.49
1.2	76.68	92.79
1.5	80.44	97.34
4.3	92.19	111.57

Figure C-3 displays the baseline adjusted parametric performance curve, the baseline adjusted parametric performance curve that incorporates the average level of long-term mercury control due to the injection of DARCO® Hg-LH as well as the adjusted long-term data calculated in step 3.

Figure C-3 – Adjusted Parametric Performance Curves and Long-Term Data



Step 5

The baseline and long-term adjusted parametric performance data from step 4 was then used to develop the final adjusted non-linear algorithm shown below. The form of this equation ensures that the level of mercury control due to ACI approaches, but never exceeds 100%. Details of the regression results are provided in Appendix E of this report.

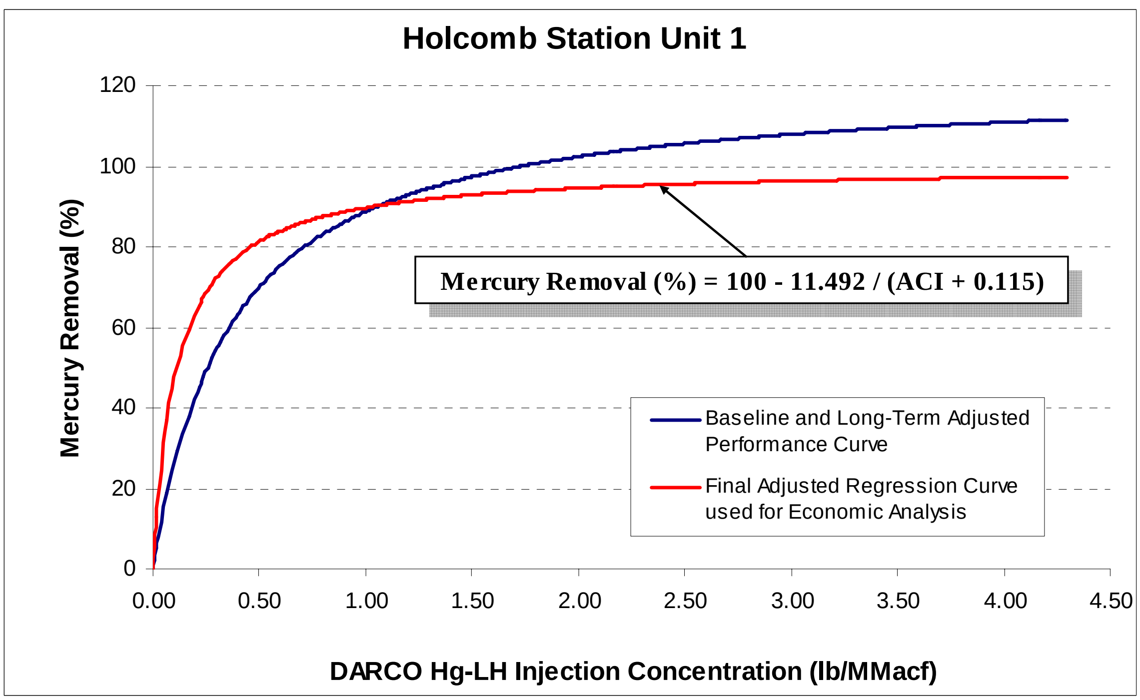
$$\%\,Hg\ removal\ due\ to\ ACI = 100 - \frac{11.492}{ACI + 0.115}$$

Table C-3 presents a comparison of the baseline and long-term adjusted parametric performance data to the results of the final adjusted algorithm that was used for the economic analysis. Figure C-4 presents that same data plotted graphically.

Table C-3 – Parametric Performance Data – Adjustment to Limit Maximum Mercury Removal to less than 100%

	Parametric Performance Data – Adjusted for Baseline and Long-Term Data	Final Adjusted Algorithm
[DARCO® Hg-LH], lb/MMacf	Mercury Removal due to ACI, %	Mercury Removal due to ACI, %
0.0	0.00	0.07
0.7	79.49	85.85
1.2	92.79	91.24
1.5	97.34	92.87
4.3	111.57	97.40

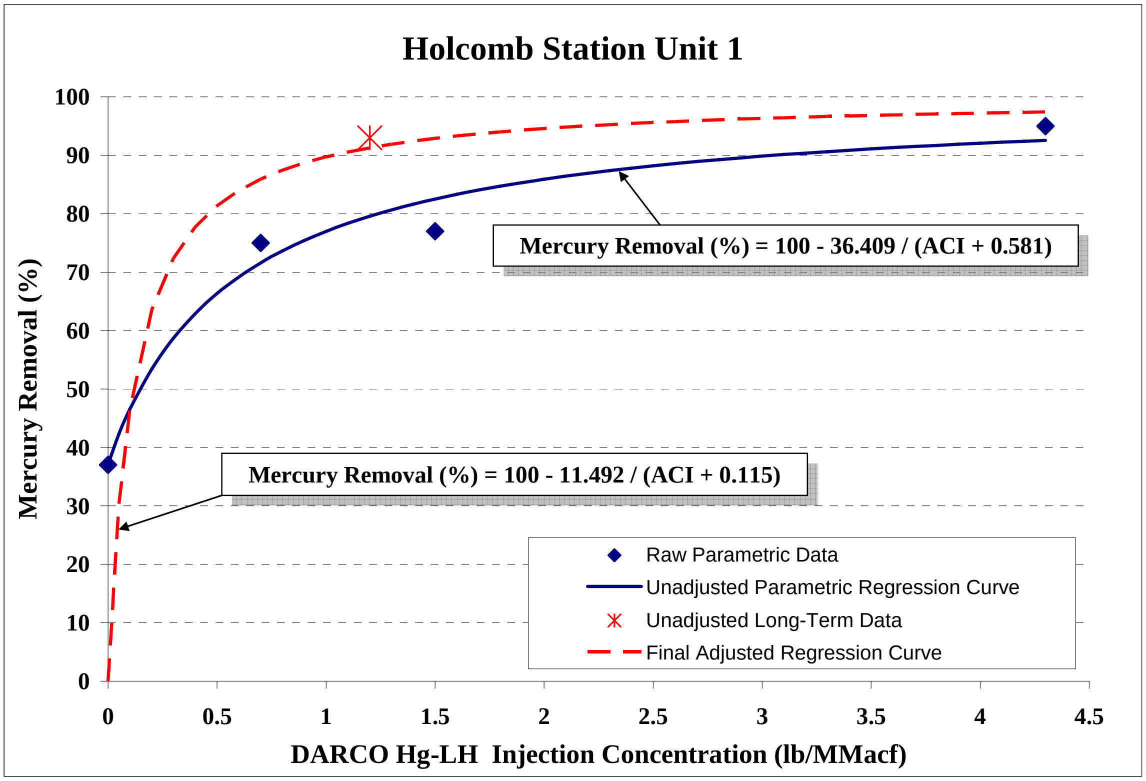
Figure C-4 – Parametric Performance Data - Adjustment to Limit Maximum Mercury Removal to less than 100%



Summary of Data Adjustment for Holcomb Station Unit 1

Figure C-5 illustrates the final adjusted (dashed curve) and unadjusted (solid curve) mercury removal performance of DARCO® Hg-LH at Holcomb. The diamond symbols represent the raw parametric data and the asterisk represents the average total mercury capture observed during the long-term continuous injection trial.

Figure C-5 – Summary of Unadjusted and Adjusted ACI Performance Data

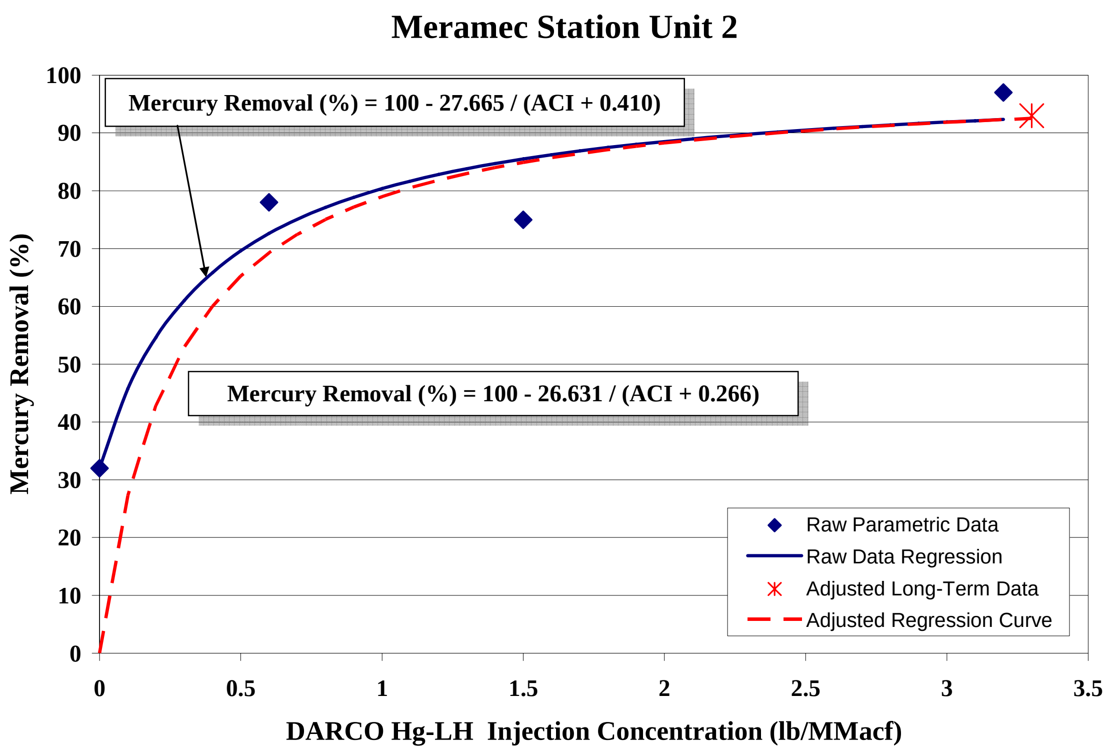


Meramec Station Unit 2

The entire data adjustment methodology was also applied to the parametric and average long-term performance data obtained during full-scale field testing at Meramec Station. Once again, the economics of mercury control are based on the performance of DARCO® Hg-LH. Injection upstream of the existing CS-ESP resulted in an average total mercury removal of 93% with an average DARCO® Hg-LH injection concentration of 3.3 lb/MMacf during the long-term continuous injection trial. The average level of long-term mercury control that is attributable to the injection of DARCO® Hg-LH was calculated to be 92.98% using a predicted baseline mercury capture of 0.27% for an injection concentration of 3.3 lb/MMacf. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\% Hg\ \mathrm{Re}moval\ due\ to\ ACI = 100 - \frac{26.631}{ACI + 0.266}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the unadjusted parametric regression curve (solid curve) for Meramec Station Unit 2. The asterisk represents the average total mercury capture observed during the long-term continuous injection trial with DARCO® Hg-LH.

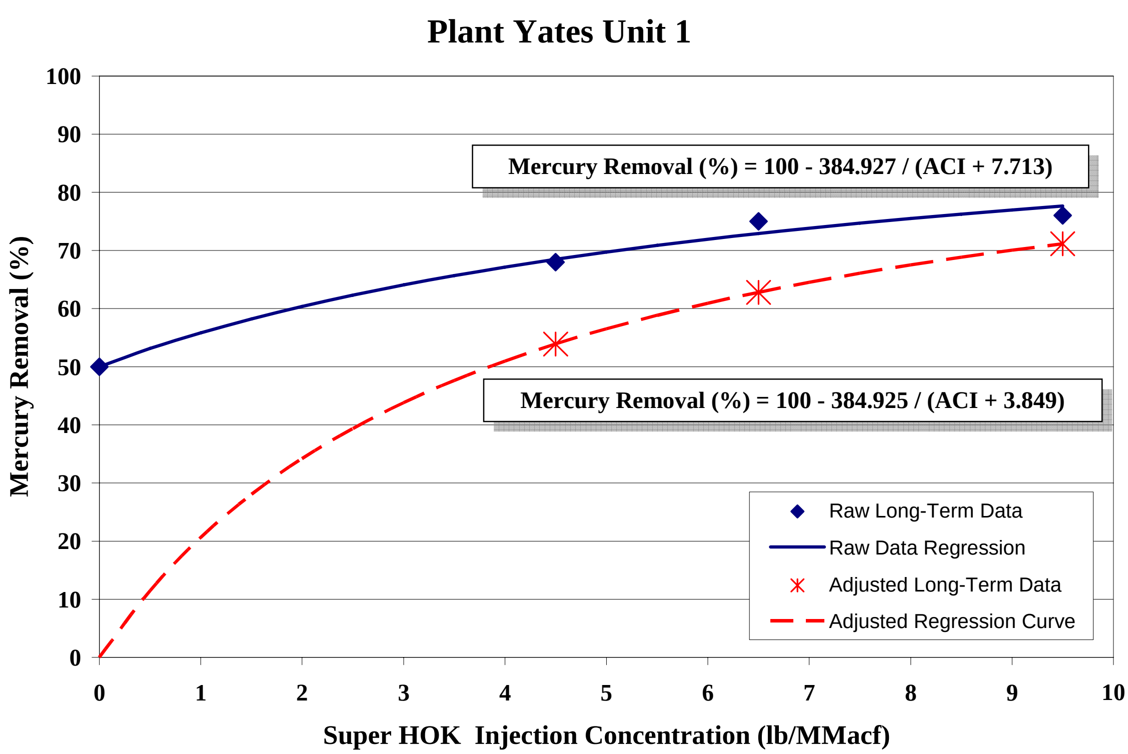


Plant Yates Unit 1

The economic analysis for Plant Yates is based on the performance of Super HOK during the long-term continuous injection trial since three distinct ACI concentrations were investigated over the 30-day period. Therefore, the average long-term data was simply adjusted to account for the baseline mercury removal of approximately 50% observed prior to the long-term test. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\%\,Hg\,\mathrm{Re}\,moval\;due\,to\,ACI = 100 - \frac{384.925}{ACI + 3.849}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the unadjusted raw regression curve (solid curve) for Plant Yates Unit 1. The asterisks represent the average long-term mercury capture that is directly attributable to the injection of Super HOK.



Leland Olds Unit 1

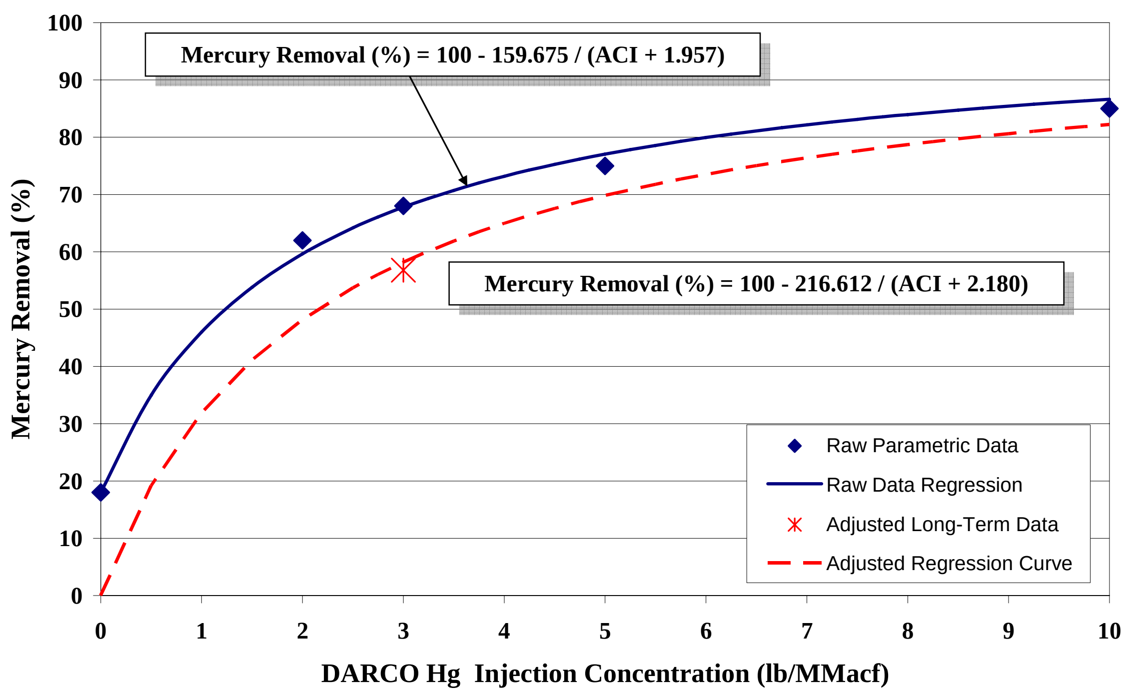
The economic analysis is intended to show the mercury capture efficiency of DARCO® Hg when the low-rank coal is treated with an aqueous $CaCl_2$ solution prior to combustion. To complete this analysis, the entire data adjustment methodology shown for Holcomb Station was completed. During long-term testing, an average DARCO® Hg injection concentration of 2.7 lb/MMacf, coupled with $CaCl_2$ coal treatment, was required to achieve 58% total mercury removal. The average level of long-term mercury control that is attributable to the mercury-specific control technologies was calculated to be 56.80% using a predicted baseline mercury capture of 2.79% for an injection concentration of 2.7 lb/MMacf.

The final adjusted algorithm, derived from a statistical regression, is shown below. For this analysis, the adjusted algorithm actually yields the level of mercury control that is attributable to the co-injection of an aqueous $CaCl_2$ solution onto the coal and DARCO® Hg into the flue gas upstream of the existing CS-ESP. Details of the regression results are provided in Appendix E of this report.

$$\%\,Hg\ \mathrm{Re}\,moval\ due\ to\ ACI = 100 - \frac{216.612}{ACI + 2.180}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the unadjusted parametric regression curve (solid curve) for Leland Olds Unit 1. The asterisk represents the average long-term mercury capture that is directly attributable to the co-injection of an aqueous $CaCl_2$ solution and DARCO® Hg.

Leland Olds Unit 1 (with $CaCl_2$ coal additive)

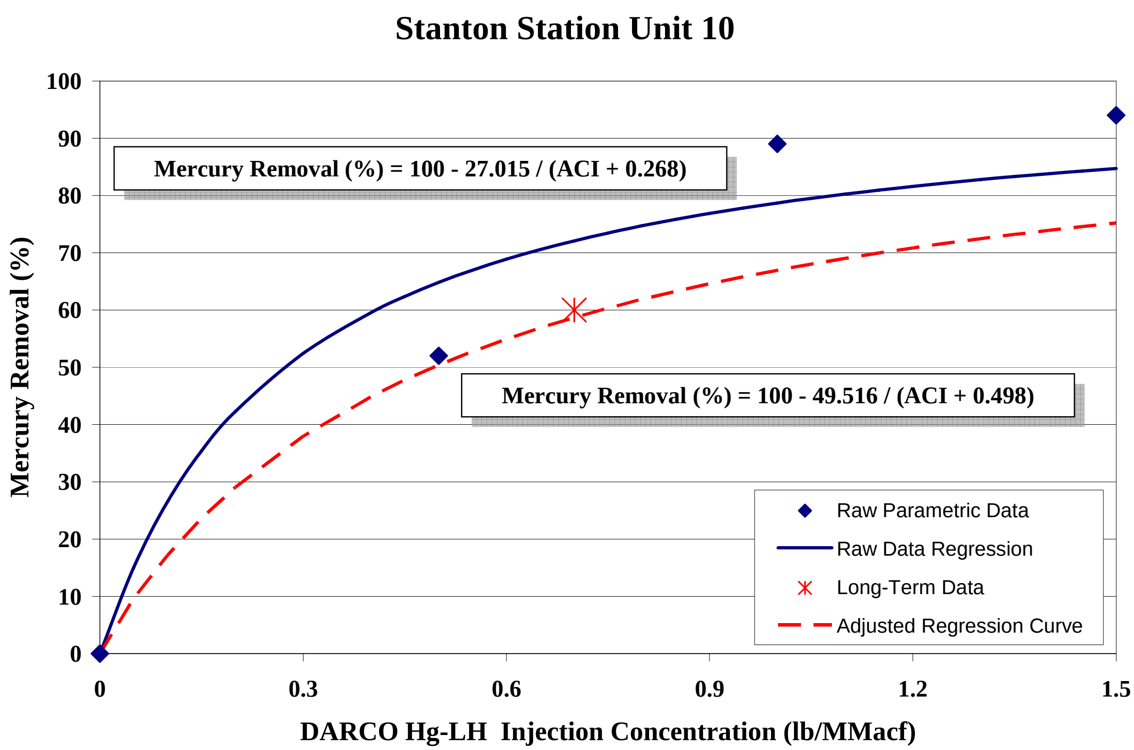


Stanton Station Unit 10

During full-scale field testing, baseline mercury capture across the SDA/FF configuration was 0% throughout the parametric testing campaign. Therefore, the raw parametric regression curve was simply scaled to include the average long-term results where 60% mercury capture was observed at an average DARCO® Hg-LH injection concentration of 0.7 lb/MMacf. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\% \, Hg \, Removal \, due \, to \, ACI = 100 - \frac{49.516}{ACI + 0.498}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the unadjusted parametric regression curve (solid curve) for Stanton Station Unit 10. The asterisk represents the average total mercury capture observed during the long-term continuous injection trial with DARCO® Hg-LH.

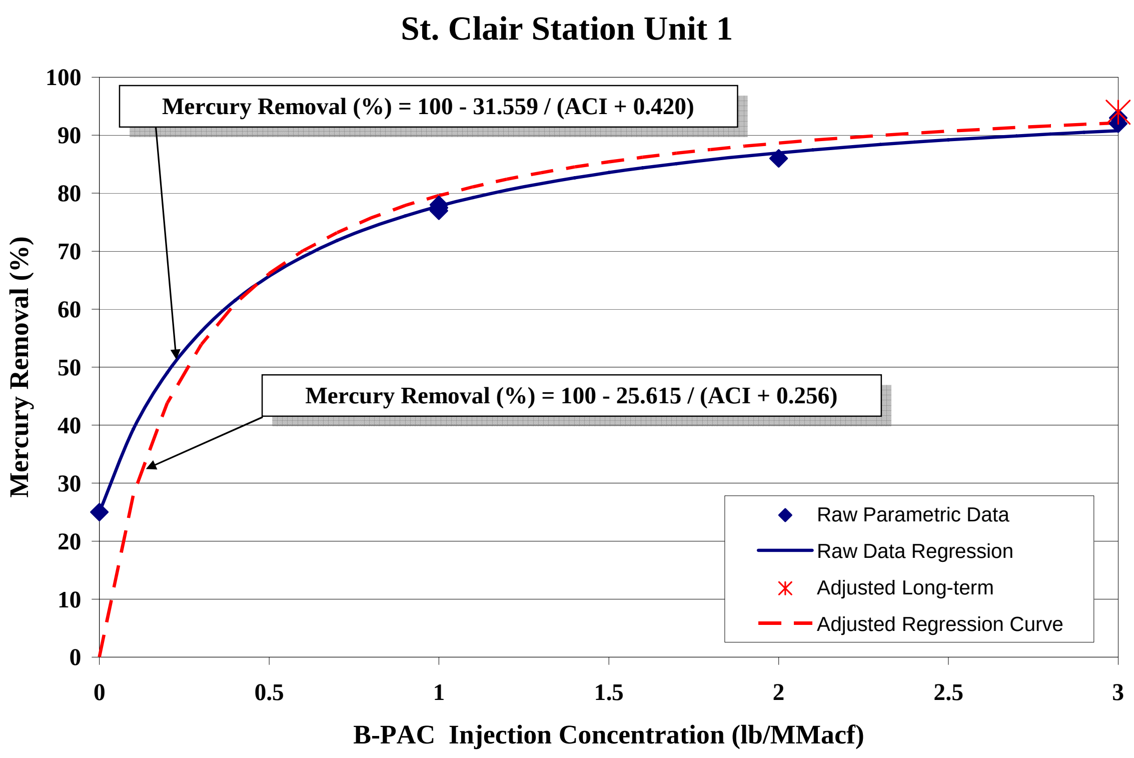


St. Clair Station Unit 1

The entire data adjustment methodology was also applied to the parametric and average long-term performance data obtained during full-scale field testing at St. Clair Station. The economics of mercury control for this unit are based on the performance of B-PAC™. Injection upstream of the existing CS-ESP resulted in an average total mercury removal of 94% with an average B-PAC™ injection concentration of 3 lb/MMacf during the long-term continuous injection trial. The average level of long-term mercury control that is attributable to the injection of B-PAC™ was calculated to be 93.98% using a predicted baseline mercury capture of 0.28% for an injection concentration of 3 lb/MMacf. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\%\,Hg\,\mathrm{Re}moval\;due\,to\,ACI = 100 - \frac{25.615}{ACI + 0.256}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the unadjusted parametric regression curve (solid curve) for St. Clair Station Unit 1. The asterisk represents the average total mercury capture observed during the long-term continuous injection trial with B-PAC™.

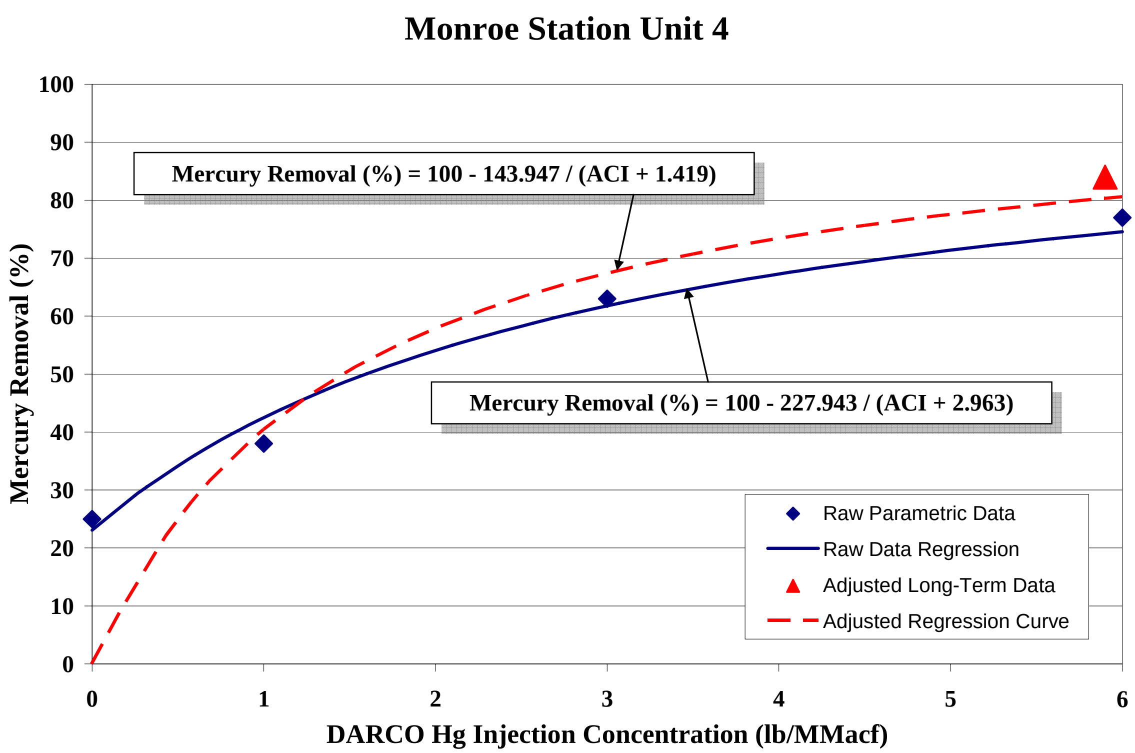


Monroe Station Unit 4

The data adjustment methodology was also applied to the parametric and average long-term performance data obtained during full-scale field testing at Monroe Station. The economics of mercury control for this unit are based on the performance of DARCO® Hg with an upstream SCR in-service. Injection upstream of the existing CS-ESP resulted in an average total mercury removal of 87% with an average DARCO® Hg injection concentration of 3 lb/MMacf during the long-term continuous injection trial. The average level of long-term mercury control that is attributable to the injection of DARCO® Hg is 84%. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\% Hg \text{ Re} moval\ due\ to\ ACI = 100 - \frac{143.947}{ACI + 1.419}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the unadjusted parametric regression curve (solid curve) for Monroe Station Unit 4. The red triangle represents the average mercury capture observed during the long-term continuous injection trial with DARCO® Hg.

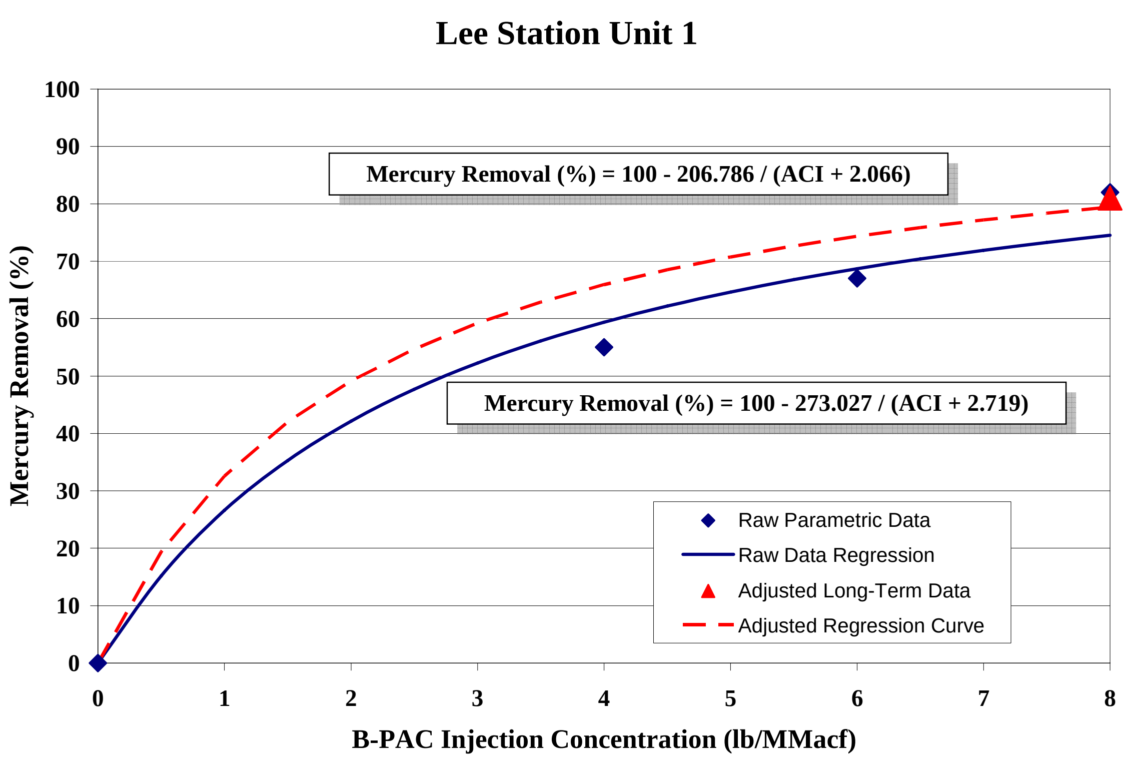


Lee Station Unit 1

The data adjustment methodology was also applied to the parametric and average long-term performance data obtained during full-scale field testing at Lee Station. The economics of mercury control for this unit are based on the performance of cold-side B-PAC™ injection with the SO_3 FGC system idled. Injection upstream of the existing CS-ESP resulted in an average total mercury removal of 85% with an average B-PAC™ injection concentration of 8 lb/MMacf during the long-term continuous injection trial. The average level of long-term mercury control that is attributable to the injection of B-PAC™ is 81%. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\%\, Hg\ \mathrm{Re}\, moval\ due\ to\ ACI = 100 - \frac{206.786}{ACI + 2.066}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the parametric regression curve (solid curve) for Lee Station Unit 1. The red triangle represents the average mercury capture observed during the long-term continuous injection trial with B-PAC™.

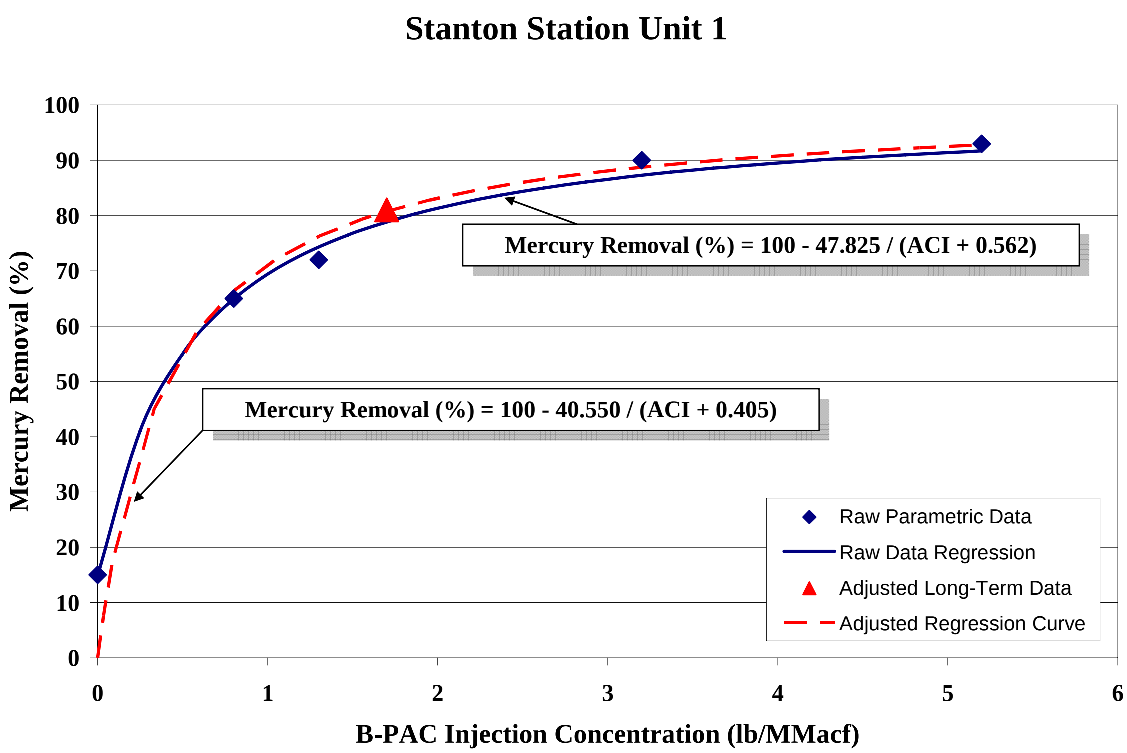


Stanton Station Unit 1

The data adjustment methodology was also applied to the parametric and average long-term performance data obtained during full-scale field testing at Stanton Station. The economics of mercury control for this unit are based on the performance of B-PAC™ injection. Injection upstream of the existing CS-ESP resulted in an average total mercury removal of 85% with an average B-PAC™ injection concentration of 1.7 lb/MMacf during the long-term continuous injection trial. The average level of long-term mercury control that is attributable to the injection of B-PAC™ is 81%. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\%\,Hg\,\mathrm{Re}\,moval\;due\;to\;ACI = 100 - \frac{40.550}{ACI + 0.405}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the unadjusted parametric regression curve (solid curve) for Stanton Station Unit 1. The red triangle represents the average mercury capture observed during the long-term continuous injection trial with B-PAC™.

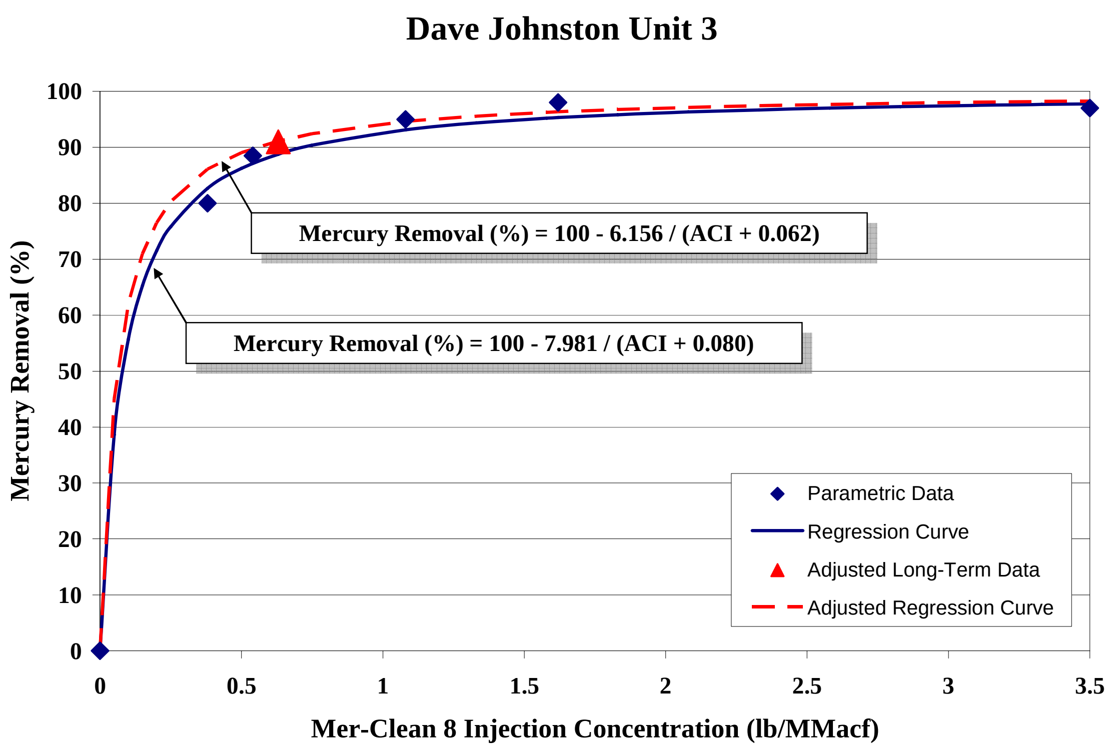


Dave Johnston Unit 3

The data adjustment methodology was also applied to the parametric and average long-term performance data obtained during full-scale field testing at Dave Johnston. The economics of mercury control for this unit are based on the performance of Mer-Clean™ 8 injection. Injection upstream of the existing CS-ESP resulted in an average total mercury removal of 92% with an average Mer-Clean™ 8 injection concentration of 0.63 lb/MMacf during the long-term continuous injection trial. The average level of long-term mercury control that is attributable to the injection of Mer-Clean™ 8 is 91%. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\%\,Hg\ Removal\ due\ to\ ACI = 100 - \frac{6.156}{ACI + 0.062}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the parametric regression curve (solid curve) for Dave Johnston Unit 3. The red triangle represents the average mercury capture observed during the long-term continuous injection trial with Mer-Clean™ 8.

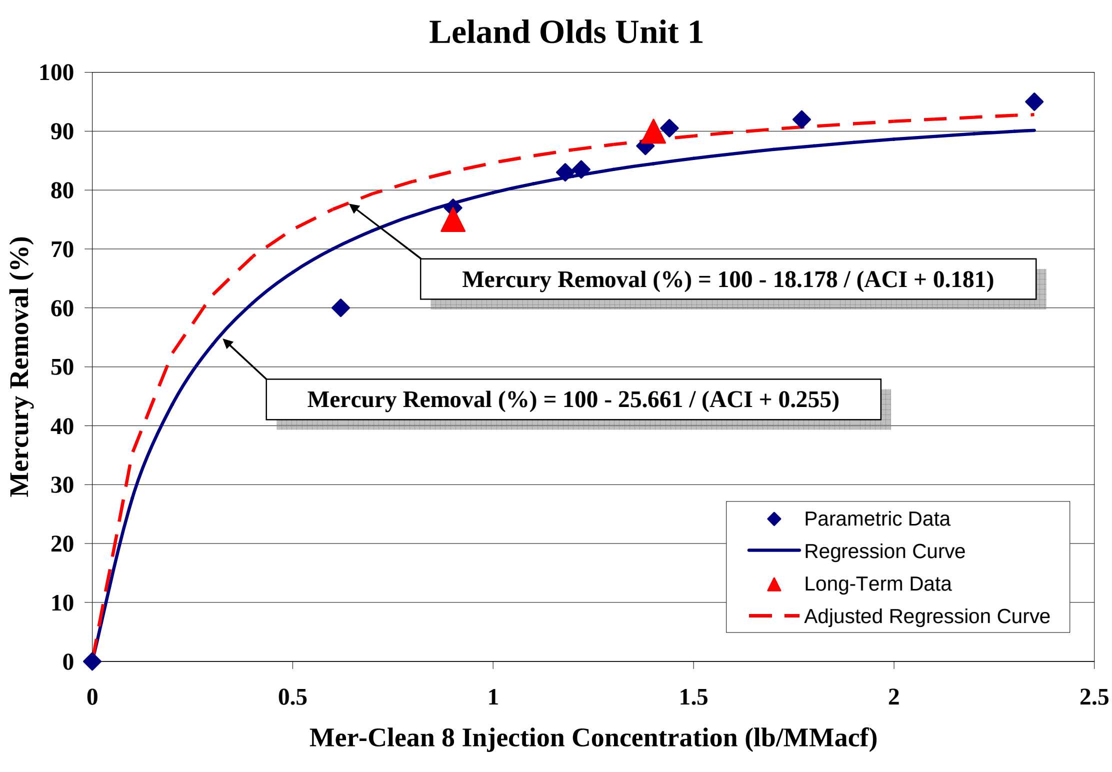


Leland Olds Station Unit 1

The data adjustment methodology was also applied to the parametric and average long-term performance data obtained during full-scale field testing at Leland Olds Station. The economics of mercury control for this unit are based on the performance of Mer-Clean™ 8 injection. During long-term testing, injection upstream of the existing CS-ESP resulted in average total mercury removal values of 75% and 90% with average Mer-Clean™ 8 injection concentrations of 0.9 and 1.4 lb/MMacf, respectively. The long-term data was not adjusted since no baseline mercury capture was observed prior to these tests. The parametric regression curve was simply scaled to incorporate the long-term field testing results. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\%\,Hg\,\mathrm{Re}\,moval\;due\,to\,ACI = 100 - \frac{18.178}{ACI + 0.181}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the parametric regression curve (solid curve) for Leland Olds Unit 1. The red triangles represent the average mercury capture observed during the long-term continuous injection trial with Mer-Clean™ 8.

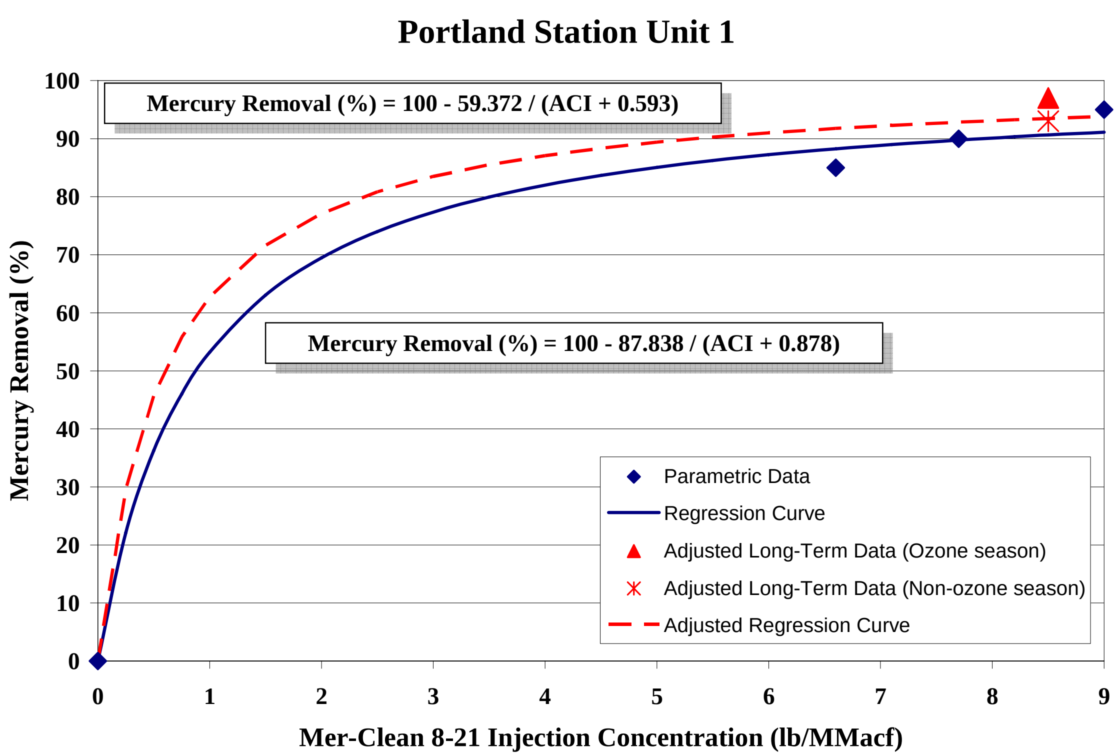


Portland Station Unit 1

The data adjustment methodology was also applied to the parametric and average long-term performance data obtained during full-scale field testing at Portland Station. The economics of mercury control for this unit are based on the performance of Mer-Clean™ 8-21 injection. During long-term testing, injection upstream of the existing CS-ESP resulted in average total mercury removal values of 95% and 98% with an average Mer-Clean™ 8-21 injection concentration of 8.5 lb/MMacf during the non-ozone and ozone seasons, respectively. The average levels of long-term mercury control that are attributable to the injection of Mer-Clean™ 8-21 are 93% and 97% during the non-ozone and ozone seasons, respectively. Note that the parametric regression curve was scaled to incorporate the overall average level of mercury capture (95%) observed during these long-term testing periods. The final adjusted algorithm, derived from a statistical regression, is shown below. Details of the regression results are provided in Appendix E of this report.

$$\%\,Hg\ \mathrm{Re}moval\ due\ to\ ACI = 100 - \frac{59.372}{ACI + 0.593}$$

The figure below displays the final adjusted regression curve (dashed curve) as well as the parametric regression curve (solid curve) for Portland Station Unit 1. The red triangle and asterisk represent the average mercury capture observed during the long-term continuous injection trial with Mer-Clean™ 8-21.



APPENDIX D

Capital Cost Estimates

Activated Carbon Storage and Injection System
As part of the DOE/NETL Phase II field testing program, ADA-ES recently completed economic evaluations of mercury control via ACI based on the results obtained during full-scale testing at the Holcomb, Meramec, and Monroe Stations.[14,15,20] With input obtained from NORIT Americas, which has built and installed dozens of similar systems at waste-to-energy and incineration plants, ADA-ES provided estimates for the total capital cost required to install a full-scale PAC storage and injection system. These estimates were used to approximate the capital costs required to retrofit similar ACI systems at some of the other Phase II field testing sites included in this economic analysis. Meanwhile, ALSTOM-PPL provided an installed capital cost estimate of about $8/kW for the Mer-Cure™ system.

The total direct cost (TDC) for the ACI system is calculated as the sum of the following cost components:

(1) *Uninstalled equipment cost* (e.g., bulk storage silo, pneumatic conveying systems, foundations, distribution manifold, injection lances, etc.);
(2) Materials and labor associated with *site integration* (e.g., electrical supply upgrades, process control integration, instrument air, adequate lighting, etc.);
(3) *Sales tax* of 6%; and
(4) *Installation costs* that can vary significantly depending on plant-specific retrofit issues.

The indirect costs were estimated as percentages of the TDC using the EPRI TAG™ methodology. For instance, 10% of the TDC was set aside for general facility fees as well as engineering fees. The project contingency was calculated as 15% of the TDC, while 5% was used for the process contingency since the technology is relatively simple. The total capital requirement (TCR) for the ACI system is calculated with the inclusion of indirect costs and contingencies. However, the capital cost required to install and calibrate a mercury monitoring system were excluded from this economic analysis. The TCR is commonly expressed as a function of unit capacity ($/kW). Note that no adjustments were made for interest during construction since the ACI system can be installed in a few months. Tables D-1 and D-2 provide a detailed breakdown of the individual cost components used to calculate the TCR for the ACI systems.

Table D-1 – Itemized Capital Cost Estimates for ACI Technology

Unit	Holcomb Unit 1	Meramec Unit 2	Yates Unit 1	Leland Olds Unit 1	Stanton Unit 10	St. Clair Unit 1
ACI Equipment	$711,000	$696,000	$691,000	$706,000	$691,000	$696,000
Installed SEA Equipment	N/A	N/A	N/A	$125,000	N/A	N/A
Site Integration	$51,900	$50,800	$50,400	$51,500	$50,400	$50,800
Installation	$124,000	$124,000	$118,000	$120,000	$118,000	$119,000
Taxes	$45,800	$44,800	$44,500	$45,500	$44,500	$44,800
Indirects / Contingencies	$373,000	$366,000	$362,000	$370,000	$362,000	$364,000
TCR, $	$1,306,000	$1,282,000	$1,266,000	$1,418,000	$1,266,000	$1,275,000
TCR, $/kW	$3.63	$9.16	$12.66	$6.45	$21.10	$8.79

Table D-2 - Itemized Capital Cost Estimates for ACI Technology

Unit	Monroe Unit 4	Lee Unit 1	Stanton Unit 1	Dave Johnston Unit 3	Leland Olds Unit 1 (Mer-Cure)	Portland Unit 1
ACI Equipment	$1,770,000	$691,000	$696,000	$1,130,000	$1,020,000	$748,000
Installed SEA Equipment	N/A	N/A	N/A	N/A	N/A	N/A
Site Integration	$54,700	$50,400	$50,800	$54,300	$53,600	$54,600
Installation	$212,000	$118,000	$119,000	$120,000	$120,000	$120,000
Taxes	$109,000	$44,500	$44,800	$70,800	$64,400	$48,200
Indirects / Contingencies	$857,000	$362,000	$364,000	$548,000	$503,000	$388,000
TCR, $	$3,001,000	$1,266,000	$1,275,000	$1,919,000	$1,760,000	$1,360,000
TCR, $/kW	$3.82	$16.02	$8.50	$8.00	$8.00	$8.00

APPENDIX E

Non-Linear Regression Analysis

Holcomb Station Unit 1
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	3589.351	4.400	.400
1.1	1445.021	34.747	1.276
2.0	1445.021	34.747	1.276
2.1	70593.264	22.580	-.801
2.2	145.851	37.098	.700
3.0	145.851	37.098	.700
3.1	54.243	36.141	.555
4.0	54.243	36.141	.555
4.1	48.180	36.329	.578
5.0	48.180	36.329	.578
5.1	48.167	36.404	.581
6.0	48.167	36.404	.581
6.1	48.167	36.408	.581
7.0	48.167	36.408	.581
7.1	48.167	36.409	.581

Derivatives are calculated numerically.

b. Run stopped after 15 model evaluations and 7 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	36.409	8.654	-.826	73.643
B	.581	.154	-.080	1.242

Correlations of Parameter Estimates

	A	B
A	1.000	.957
B	.957	1.000

ANOVA [a]

Source	Sum of Squares	df	Mean Squares
Regression	21899.833	2	10949.917
Residual	48.167	2	24.083
Uncorrected Total	21948.000	4	
Corrected Total	1784.000	3	

Dependent variable: VAR00003

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .973.

Holcomb Station Unit 1
Adjusted Parametric & Long-Term Data - Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	1309.364	40.000	.400
1.1	705.360	1.907	.017
2.0	705.360	1.907	.017
2.1	445.698	5.178	.047
3.0	445.698	5.178	.047
3.1	302.055	8.260	.079
4.0	302.055	8.260	.079
4.1	265.367	11.543	.114
5.0	265.367	11.543	.114
5.1	264.046	11.496	.115
6.0	264.046	11.496	.115
6.1	264.046	11.492	.115
7.0	264.046	11.492	.115
7.1	264.046	11.492	.115

Derivatives are calculated numerically.

b. Run stopped after 14 model evaluations and 7 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	11.492	6.681	-9.769	32.752
B	.115	.068	-.101	.331

Correlations of Parameter Estimates

	A	B
A	1.000	.987
B	.987	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	36587.601	2	18293.801
Residual	264.046	3	88.015
Uncorrected Total	36851.647	5	
Corrected Total	7790.332	4	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .966.

Meramec Station Unit 2
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	1429.372	40.000	.400
1.1	161.905	27.617	.406
2.0	161.905	27.617	.406
2.1	161.663	27.648	.409
3.0	161.663	27.648	.409
3.1	161.663	27.663	.410
4.0	161.663	27.663	.410
4.1	161.663	27.665	.410

Derivatives are calculated numerically.

b. Run stopped after 8 model evaluations and 4 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	27.665	11.990	-23.925	79.254
B	.410	.194	-.423	1.242

Correlations of Parameter Estimates

	A	B
A	1.000	.961
B	.961	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	21980.337	2	10990.169
Residual	161.663	2	80.831
Uncorrected Total	22142.000	4	
Corrected Total	2261.000	3	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .928.

Meramec Station Unit 2
Adjusted Parametric & Long-Term Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	133.304	40.000	.400
1.1	2.928	24.980	.250
2.0	2.928	24.980	.250
2.1	.281	26.610	.266
3.0	.281	26.610	.266
3.1	.281	26.631	.266
4.0	.281	26.631	.266
4.1	.281	26.631	.266
5.0	.281	26.631	.266
5.1	.281	26.631	.266

Derivatives are calculated numerically.

b. Run stopped after 10 model evaluations and 5 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	26.631	.388	24.959	28.302
B	.266	.004	.249	.284

Correlations of Parameter Estimates

	A	B
A	1.000	.970
B	.970	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	20646.840	2	10323.420
Residual	.281	2	.140
Uncorrected Total	20647.120	4	
Corrected Total	5385.359	3	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = 1.000.

Plant Yates Unit 1
Raw Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter	
		A	B
1.0	3636.724	4.400	.400
1.1	2507.508	184.347	15.341
2.0	2507.508	184.347	15.341
2.1	6939.842	200.959	-31.330
2.2	282.914	277.918	7.246
3.0	282.914	277.918	7.246
3.1	8.242	383.971	7.827
4.0	8.242	383.971	7.827
4.1	7.260	384.937	7.711
5.0	7.260	384.937	7.711
5.1	7.260	384.927	7.713
6.0	7.260	384.927	7.713
6.1	7.260	384.927	7.713

Derivatives are calculated numerically.

b. Run stopped after 13 model evaluations and 6 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval	
			Lower Bound	Upper Bound
A	384.927	39.166	216.410	553.445
B	7.713	.952	3.615	11.811

Correlations of Parameter Estimates

	A	B
A	1.000	.962
B	.962	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	18517.740	2	9258.870
Residual	7.260	2	3.630
Uncorrected Total	18525.000	4	
Corrected Total	434.750	3	

Dependent variable: VAR00003

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .983.

Plant Yates Unit 1
Adjusted Data - Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	3116.517	40.000	.400
1.1	235.942	256.402	2.564
2.0	235.942	256.402	2.564
2.1	3.250	367.896	3.679
3.0	3.250	367.896	3.679
3.1	.001	384.634	3.846
4.0	.001	384.634	3.846
4.1	.000	384.925	3.849
5.0	.000	384.925	3.849
5.1	.000	384.925	3.849
6.0	.000	384.925	3.849
6.1	.000	384.925	3.849

Derivatives are calculated numerically.

b. Run stopped after 12 model evaluations and 6 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008, and the relative reduction between successive parameter estimates is at most PCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	384.925	.003	384.913	384.938
B	3.849	.000	3.849	3.849

Correlations of Parameter Estimates

	A	B
A	1.000	.947
B	.947	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	11727.819	2	5863.909
Residual	.000	2	.000
Uncorrected Total	11727.819	4	
Corrected Total	3049.965	3	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = 1.000.

Leland Olds 1 (DARCO Hg w/ $CaCl_2$)
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	8089.289	4.400	.400
1.1	6028.176	115.114	7.886
2.0	6028.176	115.114	7.886
2.1	14185.382	142.217	-18.491
2.2	85.574	164.554	2.247
3.0	85.574	164.554	2.247
3.1	14.503	159.051	1.918
4.0	14.503	159.051	1.918
4.1	12.652	159.570	1.955
5.0	12.652	159.570	1.955
5.1	12.651	159.670	1.957
6.0	12.651	159.670	1.957
6.1	12.651	159.675	1.957
7.0	12.651	159.675	1.957
7.1	12.651	159.675	1.957

Derivatives are calculated numerically.

b. Run stopped after 15 model evaluations and 7 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	159.675	9.851	128.326	191.024
B	1.957	.142	1.505	2.408

Correlations of Parameter Estimates

	A	B
A	1.000	.943
B	.943	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	21629.349	2	10814.675
Residual	12.651	3	4.217
Uncorrected Total	21642.000	5	
Corrected Total	2669.200	4	

Dependent variable: VAR00003

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .995.

Leland Olds 1 (DARCO Hg w/ $CaCl_2$)
Adjusted Parametric & Long-Term Data - Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	3793.744	40.000	.400
1.1	321.201	150.090	1.501
2.0	321.201	150.090	1.501
2.1	32.467	206.477	2.071
3.0	32.467	206.477	2.071
3.1	27.420	216.121	2.173
4.0	27.420	216.121	2.173
4.1	27.409	216.595	2.179
5.0	27.409	216.595	2.179
5.1	27.409	216.611	2.180
6.0	27.409	216.611	2.180
6.1	27.409	216.612	2.180

Derivatives are calculated numerically.

b. Run stopped after 12 model evaluations and 6 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	216.612	12.175	182.808	250.415
B	2.180	.152	1.758	2.601

Correlations of Parameter Estimates

	A	B
A	1.000	.936
B	.936	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	19950.658	2	9975.329
Residual	27.409	4	6.852
Uncorrected Total	19978.067	6	
Corrected Total	3716.709	5	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .993.

Stanton Station Unit 10
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	9854.876	4.400	.400
1.1	57859.289	23.663	-1.140
1.2	4373.061	6.864	.150
2.0	4373.061	6.864	.150
2.1	1352.967	9.064	.108
3.0	1352.967	9.064	.108
3.1	756.593	13.008	.132
4.0	756.593	13.008	.132
4.1	443.448	19.927	.198
5.0	443.448	19.927	.198
5.1	357.536	27.147	.270
6.0	357.536	27.147	.270
6.1	357.413	26.992	.268
7.0	357.413	26.992	.268
7.1	357.412	27.018	.268
8.0	357.412	27.018	.268
8.1	357.412	27.014	.268
9.0	357.412	27.014	.268
9.1	357.412	27.015	.268

Derivatives are calculated numerically.

b. Run stopped after 19 model evaluations and 9 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	27.015	11.648	-23.102	77.132
B	.268	.125	-.269	.805

Correlations of Parameter Estimates

	A	B
A	1.000	.959
B	.959	1.000

ANOVA [a]

Source	Sum of Squares	df	Mean Squares
Regression	19103.588	2	9551.794
Residual	357.412	2	178.706
Uncorrected Total	19461.000	4	
Corrected Total	5654.750	3	

Dependent variable: VAR00003

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .937.

Stanton Station Unit 10
Adjusted Parametric & Long-Term Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	122.194	40.000	.400
1.1	39.850	48.495	.487
2.0	39.850	48.495	.487
2.1	39.073	49.473	.498
3.0	39.073	49.473	.498
3.1	39.071	49.515	.498
4.0	39.071	49.515	.498
4.1	39.071	49.516	.498
5.0	39.071	49.516	.498
5.1	39.071	49.516	.498

Derivatives are calculated numerically.

b. Run stopped after 10 model evaluations and 5 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	49.516	4.148	36.314	62.718
B	.498	.050	.339	.658

Correlations of Parameter Estimates

	A	B
A	1.000	.939
B	.939	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	15732.895	2	7866.447
Residual	39.071	3	13.024
Uncorrected Total	15771.966	5	
Corrected Total	3276.365	4	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .988.

St. Clair Station Unit 1
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	5820.850	4.400	.400
1.1	291.969	31.549	.538
2.0	291.969	31.549	.538
2.1	60.707	30.843	.375
3.0	60.707	30.843	.375
3.1	8.694	31.480	.415
4.0	8.694	31.480	.415
4.1	8.209	31.560	.420
5.0	8.209	31.560	.420
5.1	8.209	31.559	.420
6.0	8.209	31.559	.420
6.1	8.209	31.559	.420

Derivatives are calculated numerically.

b. Run stopped after 12 model evaluations and 6 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	31.559	1.070	28.941	34.177
B	.420	.017	.380	.461

Correlations of Parameter Estimates

	A	B
A	1.000	.922
B	.922	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	49151.291	2	24575.646
Residual	8.209	6	1.368
Uncorrected Total	49159.500	8	
Corrected Total	3255.000	7	

Dependent variable: VAR00003

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .997.

St. Clair Station Unit 1
Adjusted Parametric & Long-Term Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	337.787	40.000	.400
1.1	14.431	24.013	.240
2.0	14.431	24.013	.240
2.1	9.369	25.607	.256
3.0	9.369	25.607	.256
3.1	9.369	25.615	.256
4.0	9.369	25.615	.256
4.1	9.369	25.615	.256

Derivatives are calculated numerically.

b. Run stopped after 8 model evaluations and 4 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	25.615	.904	23.402	27.828
B	.256	.010	.232	.280

Correlations of Parameter Estimates

	A	B
A	1.000	.946
B	.946	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	50687.156	2	25343.578
Residual	9.369	6	1.562
Uncorrected Total	50696.525	8	
Corrected Total	6622.611	7	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .999.

Monroe Station Unit 4
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	2659.852	40.000	.400
1.1	533.864	117.954	1.281
2.0	533.864	117.954	1.281
2.1	79.720	191.246	2.309
3.0	79.720	191.246	2.309
3.1	32.142	225.604	2.899
4.0	32.142	225.604	2.899
4.1	31.232	228.251	2.967
5.0	31.232	228.251	2.967
5.1	31.230	227.919	2.962
6.0	31.230	227.919	2.962
6.1	31.230	227.946	2.963
7.0	31.230	227.946	2.963
7.1	31.230	227.943	2.963

Derivatives are calculated numerically.

b. Run stopped after 14 model evaluations and 7 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	227.943	33.710	82.901	372.986
B	2.963	.515	.746	5.179

Correlations of Parameter Estimates

	A	B
A	1.000	.968
B	.968	1.000

ANOVA [a]

Source	Sum of Squares	df	Mean Squares
Regression	11935.770	2	5967.885
Residual	31.230	2	15.615
Uncorrected Total	11967.000	4	
Corrected Total	1664.750	3	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .981.

Monroe Station Unit 4
Adjusted Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	2161.843	40.000	.400
1.1	180.098	112.686	1.127
2.0	180.098	112.686	1.127
2.1	58.653	143.320	1.422
3.0	58.653	143.320	1.422
3.1	58.105	143.931	1.419
4.0	58.105	143.931	1.419
4.1	58.105	143.949	1.419
5.0	58.105	143.949	1.419
5.1	58.105	143.947	1.419

Derivatives are calculated numerically.

b. Run stopped after 10 model evaluations and 5 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	143.947	12.985	107.896	179.999
B	1.419	.151	1.000	1.838

Correlations of Parameter Estimates

	A	B
A	1.000	.943
B	.943	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	25744.823	2	12872.411
Residual	58.105	4	14.526
Uncorrected Total	25802.928	6	
Corrected Total	5678.508	5	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .990.

Lee Station Unit 1
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	2180.272	40.000	.400
1.1	180.193	206.733	2.067
2.0	180.193	206.733	2.067
2.1	78.230	269.334	2.688
3.0	78.230	269.334	2.688
3.1	77.887	273.104	2.720
4.0	77.887	273.104	2.720
4.1	77.887	273.024	2.719
5.0	77.887	273.024	2.719
5.1	77.887	273.027	2.719

Derivatives are calculated numerically.

b. Run stopped after 10 model evaluations and 5 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	273.027	46.206	74.219	471.836
B	2.719	.519	.484	4.954

Correlations of Parameter Estimates

	A	B
A	1.000	.948
B	.948	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	14160.113	2	7080.056
Residual	77.887	2	38.944
Uncorrected Total	14238.000	4	
Corrected Total	3834.000	3	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .980.

Lee Station Unit 1
Adjusted Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	1262.562	40.000	.400
1.1	49.280	168.040	1.680
2.0	49.280	168.040	1.680
2.1	4.514	204.999	2.049
3.0	4.514	204.999	2.049
3.1	4.425	206.794	2.066
4.0	4.425	206.794	2.066
4.1	4.425	206.786	2.066
5.0	4.425	206.786	2.066
5.1	4.425	206.786	2.066

Derivatives are calculated numerically.

b. Run stopped after 10 model evaluations and 5 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	206.786	9.211	167.156	246.416
B	2.066	.101	1.632	2.500

Correlations of Parameter Estimates

	A	B
A	1.000	.953
B	.953	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	16297.217	2	8148.608
Residual	4.425	2	2.212
Uncorrected Total	16301.641	4	
Corrected Total	4179.081	3	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .999.

Stanton Station Unit 1
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter	
		A	B
1.0	249.019	40.000	.400
1.1	26.963	46.660	.526
2.0	26.963	46.660	.526
2.1	14.472	47.806	.560
3.0	14.472	47.806	.560
3.1	14.431	47.826	.562
4.0	14.431	47.826	.562
4.1	14.431	47.825	.562
5.0	14.431	47.825	.562
5.1	14.431	47.825	.562

Derivatives are calculated numerically.

b. Run stopped after 10 model evaluations and 5 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval	
			Lower Bound	Upper Bound
A	47.825	3.513	36.645	59.004
B	.562	.046	.415	.708

Correlations of Parameter Estimates

	A	B
A	1.000	.951
B	.951	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	26368.569	2	13184.284
Residual	14.431	3	4.810
Uncorrected Total	26383.000	5	
Corrected Total	3938.000	4	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .996.

Stanton Station Unit 1
Adjusted Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	9.545	40.000	.400
1.1	9.288	40.555	.405
2.0	9.288	40.555	.405
2.1	9.288	40.550	.405
3.0	9.288	40.550	.405
3.1	9.288	40.550	.405

Derivatives are calculated numerically.

b. Run stopped after 6 model evaluations and 3 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	40.550	1.786	35.590	45.509
B	.405	.020	.351	.459

Correlations of Parameter Estimates

	A	B
A	1.000	.950
B	.950	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	33725.822	2	16862.911
Residual	9.288	4	2.322
Uncorrected Total	33735.110	6	
Corrected Total	6090.844	5	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .998.

Dave Johnston Unit 3
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	2797.623	40.000	.400
1.1	3023.843	-7.601	-.074
1.2	692.567	15.330	.196
2.0	692.567	15.330	.196
2.1	57704.603	5.539	.016
2.2	251.012	14.741	.150
3.0	251.012	14.741	.150
3.1	70.007	10.872	.111
4.0	70.007	10.872	.111
4.1	21.171	7.763	.077
5.0	21.171	7.763	.077
5.1	20.276	7.984	.080
6.0	20.276	7.984	.080
6.1	20.275	7.981	.080
7.0	20.275	7.981	.080
7.1	20.275	7.981	.080

Derivatives are calculated numerically.

b. Run stopped after 16 model evaluations and 7 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	7.981	.902	5.478	10.485
B	.080	.009	.054	.105

Correlations of Parameter Estimates

	A	B
A	1.000	.981
B	.981	1.000

ANOVA [a]

Source	Sum of Squares	df	Mean Squares
Regression	42249.975	2	21124.988
Residual	20.275	4	5.069
Uncorrected Total	42270.250	6	
Corrected Total	7233.208	5	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .997.

Dave Johnston Unit 3
Adjusted Nonlinear Regression Analysis

Iteration History [b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	3276.199	40.000	.400
1.1	3709.032	-10.076	-.097
1.2	888.293	14.572	.192
2.0	888.293	14.572	.192
2.1	69766.385	3.196	-.019
2.2	346.187	14.126	.144
3.0	346.187	14.126	.144
3.1	116.320	10.283	.105
4.0	116.320	10.283	.105
4.1	16.728	5.763	.056
5.0	16.728	5.763	.056
5.1	11.449	6.158	.061
6.0	11.449	6.158	.061
6.1	11.421	6.156	.062
7.0	11.421	6.156	.062
7.1	11.421	6.156	.062

Derivatives are calculated numerically.

b. Run stopped after 16 model evaluations and 7 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	6.156	.581	4.662	7.651
B	.062	.006	.046	.077

Correlations of Parameter Estimates

	A	B
A	1.000	.988
B	.988	1.000

ANOVA [a]

Source	Sum of Squares	df	Mean Squares
Regression	54050.050	2	27025.025
Residual	11.421	5	2.284
Uncorrected Total	54061.471	7	
Corrected Total	7873.768	6	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .999.

Leland Olds Unit 1 (Mer-Clean 8)
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter A	Parameter B
1.0	646.440	40.000	.400
1.1	219.858	23.330	.229
2.0	219.858	23.330	.229
2.1	203.883	25.717	.256
3.0	203.883	25.717	.256
3.1	203.871	25.659	.255
4.0	203.871	25.659	.255
4.1	203.871	25.661	.255
5.0	203.871	25.661	.255
5.1	203.871	25.661	.255

Derivatives are calculated numerically.

b. Run stopped after 10 model evaluations and 5 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	25.661	3.381	17.666	33.656
B	.255	.038	.166	.344

Correlations of Parameter Estimates

	A	B
A	1.000	.932
B	.932	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	56521.879	2	28260.939
Residual	203.871	7	29.124
Uncorrected Total	56725.750	9	
Corrected Total	7071.056	8	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .971.

Leland Olds Unit 1 (Mer-Clean 8)
Adjusted Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter	
		A	B
1.0	778.283	40.000	.400
1.1	104.423	12.859	.127
2.0	104.423	12.859	.127
2.1	29.162	17.991	.179
3.0	29.162	17.991	.179
3.1	29.051	18.184	.182
4.0	29.051	18.184	.182
4.1	29.051	18.178	.181
5.0	29.051	18.178	.181
5.1	29.051	18.178	.181

Derivatives are calculated numerically.

b. Run stopped after 10 model evaluations and 5 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval	
			Lower Bound	Upper Bound
A	18.178	1.783	13.229	23.127
B	.181	.019	.129	.234

Correlations of Parameter Estimates

	A	B
A	1.000	.966
B	.966	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	38325.700	2	19162.850
Residual	29.051	4	7.263
Uncorrected Total	38354.751	6	
Corrected Total	6749.645	5	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .996.

Portland Station Unit 1
Raw Parametric Data - Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter	
		A	B
1.0	112.400	40.000	.400
1.1	25.995	85.415	.854
2.0	25.995	85.415	.854
2.1	25.796	87.849	.878
3.0	25.796	87.849	.878
3.1	25.796	87.838	.878
4.0	25.796	87.838	.878
4.1	25.796	87.838	.878

Derivatives are calculated numerically.

b. Run stopped after 8 model evaluations and 4 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval	
			Lower Bound	Upper Bound
A	87.838	19.659	3.251	172.426
B	.878	.200	.019	1.737

Correlations of Parameter Estimates

	A	B
A	1.000	.987
B	.987	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	24324.204	2	12162.102
Residual	25.796	2	12.898
Uncorrected Total	24350.000	4	
Corrected Total	6125.000	3	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .996.

Portland Station Unit 1
Adjusted Nonlinear Regression Analysis

Iteration History[b]

Iteration Number	Residual Sum of Squares	Parameter	
		A	B
1.0	55.696	40.000	.400
1.1	13.095	58.916	.589
2.0	13.095	58.916	.589
2.1	13.072	59.379	.594
3.0	13.072	59.379	.594
3.1	13.072	59.371	.593
4.0	13.072	59.371	.593
4.1	13.072	59.372	.593

Derivatives are calculated numerically.

b. Run stopped after 8 model evaluations and 4 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval	
			Lower Bound	Upper Bound
A	59.372	5.637	43.719	75.024
B	.593	.058	.433	.754

Correlations of Parameter Estimates

	A	B
A	1.000	.983
B	.983	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	42114.082	2	21057.041
Residual	13.072	4	3.268
Uncorrected Total	42127.154	6	
Corrected Total	7141.598	5	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .998.

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