

MERCURY INFORMATION CLEARINGHOUSE



Quarter 6 – Mercury Control Field Demonstrations

April 2005



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QUARTER 6 – MERCURY CONTROL FIELD DEMONSTRATIONS

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REPORT AVAILABILITY

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QUARTER 6 – MERCURY CONTROL FIELD DEMONSTRATIONS

EXECUTIVE SUMMARY

Introduction

The Canadian Electricity Association (CEA) identified a need and contracted the University of North Dakota (UND) Energy & Environmental Research Center (EERC) to create and maintain an information clearinghouse on global research and development activities related to mercury emissions from coal-fired electric utilities. With the support of the CEA, the Center for Air Toxic Metals[®] (CATM[®]) Affiliates, the U.S. Department of Energy (DOE), and the Canadian Council of Ministers of the Environment (CCME), the EERC is developing comprehensive quarterly information updates to provide a detailed assessment of advances in mercury monitoring, control, policy, and related research progress.

In order to adequately address the many topics pertinent to mercury research and development and provide the detail necessary for the various stakeholders to make informed decisions, selected topics are discussed in detail in each quarterly report. Specific topics that have been addressed in previous quarterly reports include the following:

Quarter 1 – Sorbent Control Technologies for Mercury Control

Quarter 2 – Mercury Measurement

Quarter 3 – Advanced and Developmental Mercury Control Technologies

Quarter 4 – Rerelease of Mercury from Coal Combustion By-Products

Quarter 5 – Mercury Fundamentals

Mercury Policy

The CCME has been in the process of developing Canada-Wide Standards (CWS) for mercury since 1998 for several significant mercury-emitting sectors and products. Standards have been completed for base metal smelters, incinerators, mercury-containing lamps, and dental amalgam wastes. A CWS announcement is scheduled sometime in 2005 for mercury emissions from coal-fired electric power-generating plants, with implementations to begin in 2010.

In the United States, the Environmental Protection Agency (EPA) issued the first Clean Air Mercury Rule (CAMR) on March 15, 2005, to permanently cap and reduce mercury emissions from coal-fired power plants (a power plant is defined as an electrical generating facility that provides >25 MWe). The CAMR is a two-phase market-based cap-and-trade program that will build on to EPA's Clean Air Interstate Rule (CAIR), which was implemented

to permanently cap emission of sulfur dioxide (SO₂) and nitrogen oxide (NO_x) in the eastern 28 states and the District of Columbia. The first phase of CAMR begins in 2010 and will cap Hg emissions at 38 tons, a 21% reduction from current emissions (48 tons). Phase 2 will be implemented in 2018, setting the final cap at 15 tons with an overall reduction of 69%. Although the initial phase of CAMR is expected to be met as a cobenefit of wet scrubber and selective catalytic reduction (SCR) system installations to meet the CAIR, the Phase II cap of 15 tons will require additional mercury-specific controls at many power plants.

For trading purposes, EPA has established allocations for each state, the District of Columbia, and Indian Reservations based on their share of the total heat input from coal. These were then adjusted to reflect coal rank and existing air pollution control equipment. For allocation purposes, coal-firing units were subcategorized as bituminous, subbituminous, lignite, integrated gasification combined cycle (IGCC), and coal refuse. Each state will be free to decide if it wishes to participate in the trading program.

In addition to the cap-and-trade program, new coal-fired sources will have additional mercury requirements as part of the New Source Performance Standards. The requirements have been subcategorized as follows.

- Bituminous units – 21×10^{-6} lb/MWhr
- Subbituminous units
 - Wet flue gas desulfurization (FGD) – 42×10^{-6} lb/MWh
 - Dry FGD – 78×10^{-6} lb/MWh
- Lignite units – 145×10^{-6} lb/MWh
- IGCC units – 20×10^{-6} lb/MWh
- Coal refuse units – 1.4×10^{-6} lb/MWh

Quarter 6 Focus: Mercury Control Field Demonstrations

In 1999, DOE National Energy Technology Laboratory (NETL) issued a request for proposal (RFP) to test mercury control technologies at the full scale. The near-term goal of the RFP was to evaluate technologies that could achieve 50%–70% mercury removal at a cost of less than three-quarters of the estimated cost of \$50,000–\$70,000/lb (Can\$136,000–Can\$191,000/kg) mercury removed. The longer-term goal was to develop technologies that could provide up to 90% control at a cost of half to three-quarters of activated carbon injection technology by the year 2010. During 2003 and 2004, NETL issued three more RFPs to evaluate mercury control technologies through its Office of Fossil Energy's Innovation Program and through the Clean Coal Initiative. This quarterly report focuses on the results of the large-scale mercury control projects that have been recently completed or are ongoing and identifies planned future projects.

Table ES-1 summarizes 41 large-scale mercury control projects. This information identifies the lead contractor for each project, demonstration site, boiler type and size, fuel type, air pollution control device (APCD) employed, Hg control technology being evaluated, and project status. The demonstration sites represent utility boilers across the United States and one in Canada. Boiler types representing the major North American boiler manufacturers are

included. Fuel types represented include U.S. northern plains and Gulf Coast lignite, Powder River Basin subbituminous coal, high- and low-sulfur bituminous coal, and a Canadian lignite. Air pollution control technologies represented include cold- and hot-side electrostatic precipitators (c-ESP and h-ESP), various types of wet FGD systems, and spray dryer absorbers–fabric filter (SDA–FFs). All of these projects involve the evaluation of some type of additive, reagent, or sorbent for its potential to control Hg emissions in conjunction with existing air pollution control technology or modify Hg speciation in the flue gas to facilitate Hg control. Most of the projects involve the injection of some form of activated carbon into the flue gas stream. Several projects involve the use of additives to wet FGD systems to improve Hg emission control. Other approaches include coal blending or the addition of fuel additives to affect Hg speciation and control. Although several projects have been completed, most projects are ongoing, with a significant number scheduled to begin in 2005 or 2006.

Table ES-1 – Mercury Control Demonstration Projects Funded by the U.S. Department of Energy

Lead Contractor	Demonstration Site	Boiler Type/Size	Fuel Type	APCD	Hg Control Technology	Status
UND EERC	Leland Olds Station Unit 1 Basin Electric Power Cooperative	B&W wall-fired 220 MW	ND lignite	c-ESP	ACI with SEA	Complete
ADA-ES Inc.	Coal Creek Station Unit 1 Great River Energy	CE t-fired 546 MW	ND lignite	c-ESP Wet FGD	TOXECON II™	Complete
B&W	Endicott Station Michigan South Central Power Agency	B&W Stirling Boiler 55 MW	Bituminous	c-ESP Wet FGD	FGD reagent additive	Complete
B&W	Zimmer Station Cinergy	B&W Carolina boiler 1300 MW	Bituminous	c-ESP Wet FGD	FGD reagent additive	Complete
Mobotec USA	Cape Fear Station Unit 5 Progress Energy	CE t-fired 154 MW	Low-sulfur bituminous	c-ESP	Sorbent injection ROFA™/ROTAMIX™	Complete
Southern Company	E.C. Gaston Station Unit 3 Alabama Power	CE t-fired 270 MW	Low-sulfur bituminous	h-ESP COHPAC™	ACI	Ongoing
URS	Plant Yates Unit 1 Georgia Power	CE t-fired 100 MW	Low-sulfur bituminous	c-ESP	ACI	Ongoing
URS	Plant Yates Unit 2 Georgia Power	CE t-fired 100 MW	Low-sulfur bituminous	c-ESP Wet FGD	ACI	Ongoing
Sorbent Technologies Corporation	St. Clair Station Unit 1 DTE Energy	B&W wall-fired 160 MW	PRB PRB-bit. blend	c-ESP	Brominated ACI	Ongoing
Sorbent Technologies Corporation	Buck Station Duke Energy	NA	Low-sulfur bituminous	h-ESP	Brominated ACI	Ongoing
ADA-ES Inc.	Holcomb Station Sunflower Electric Power Corporation	B&W Carolina Boiler 360 MW	PRB PRB/W-bit.	SDA-FF	ACI Coal blending	Ongoing
URS	Stanton Station Unit 1 Great River Energy	FW wall-fired 150 MW	PRB	c-ESP	ACI	Ongoing
URS	Stanton Station Unit 10 Great River Energy	CE t-fired 60 MW	ND lignite	SDA-FF	ACI	Ongoing
SaskPower and UND EERC	Poplar River Power Station Units 1 and 2 SaskPower	NA 300 MW	Poplar River lignite	c-ESP	ACI Pilot-scale slipstream	Ongoing
ADA-ES Inc.	Meramec Station AmerenEU	NA 140 MW	PRB	c-ESP	ACI	Ongoing
UND EERC	Stanton Station Unit 1 Great River Energy	FW wall-fired 150 MW	PRB	c-ESP	ACI	2005
UND EERC	Antelope Valley Station Unit 1 Basin Electric Power Cooperative	CE t-fired 440 MW	ND lignite	SDA-FF	ACI ACI with SEA	2005

Continued . . .

Table ES-1 – Mercury Control Demonstration Projects Funded by the U.S. Department of Energy (continued)

Lead Contractor	Demonstration Site	Boiler Type/Size	Fuel Type	APCD	Hg Control Technology	Status
UND EERC	Milton R. Young Station Unit 2 Minnkota Power Cooperative	B&W cyclone-fired 450 MW	ND lignite	c-ESP Wet FGD	Mercury oxidation fuel/FG additives	2005
UND EERC	Monticello Station Unit 3 Texas Utilities Company	B&W wall-fired 750 MW	Texas lignite	c-ESP Wet FGD	Mercury oxidation fuel/FG additives	2005
UND EERC	Big Brown Station Texas Utilities Company	CE t-fired 600 MW	Texas lignite Lignite-PRB	c-ESP	ACI	2005
URS	Monticello Station Unit 3 Texas Utilities Company	B&W wall-fired 750 MW	Texas lignite	c-ESP Wet FGD	Wet FGD additives	2005
URS	Plant Yates Unit 2 Georgia Power	CE t-fired 100 MW	Low-sulfur bituminous	c-ESP Wet FGD	Wet FGD additive	2005
URS	Conesville Station American Electric Power	NA 400 MW	Bituminous	c-ESP Wet FGD	Wet FGD additive	2005
ADA-ES Inc.	Conesville Station American Electric Power	NA 400 MW	Bituminous	c-ESP Wet FGD	ACI	2005
ADA-ES Inc.	Laramie River Station Unit 3 Missouri Basin Power Project	B&W 550 MW	PRB	SDA-ESP	ACI	2005
ADA-ES Inc.	Monroe Station Unit 4 Detroit Edison	B&W 785 MW	PRB-bit. blend	c-ESP	ACI	2005
ADA-ES Inc.	Louisa Station Unit 1 MidAmerican	B&W 650 MW	PRB	h-ESP	Sorbent injection	2005
ADA-ES Inc.	Independence Station Unit 1 Entergy	CE 840 MW	PRB	c-ESP	TOXECON II™	TBD
ADA-ES Inc.	Gavin Station American Electric Power	B&W 1300 MW	Bituminous	c-ESP	TOXECON II™	TBD
ADA-ES Inc.	Council Bluff Unit 2 MidAmerican	NA	PRB	h-ESP	Sorbent injection	TBD
ALSTOM Power, Inc.	Dave Johnston Station PacificCorp	NA	PRB	c-ESP	ACI with additives	2005
ALSTOM Power, Inc.	Leland Olds Station Unit 1 Basin Electric Power Cooperative	B&W 440 MW	ND lignite	c-ESP	ACI with additives	2006
ALSTOM Power, Inc.	Portland Station Reliant Energy	NA	Bituminous	c-ESP	ACI with additives	2006
GE EER	John Sevier Station Tennessee Valley Authority	NA	Bituminous	NA	Combined Hg and NO _x Control	2005

Continued . . .

Table ES-1 – Mercury Control Demonstration Projects Funded by the U.S. Department of Energy (continued)

Lead Contractor	Demonstration Site	Boiler Type/Size	Fuel Type	APCD	Hg Control Technology	Status
GE EER	Lee Station Unit 3 Progress Energy	NA	Bituminous	c-ESP	Combined Hg and NO _x control	2005
Sorbent Technologies Corporation	Lee Station Unit 1 Progress Energy	NA	Bituminous	c-ESP	Brominated ACI	2005
Sorbent Technologies Corporation	Crawford Station Unit 7 Midwest Generation	NA	PRB	c-ESP	Brominated ACI	2006
Sorbent Technologies Corporation	Will County Station Midwest Generation	NA	PRB	h-ESP	Brominated ACI	TBD
Mobotec USA	Whitewater Station Richmond Power and Light	NA	NA	NA	Sorbent injection ROFA™/ROTAMIX™	2005
ADA-ES Inc.	Presque Isle Station WE Energy	NA	NA	NA	TOXECON II™	2005
Amended Silicates, LLC	Miami Fort Station Unit 6 Cinergy	NA 175 MW	Bituminous	c-ESP	Amended Silicates™	2005

ACI – activated carbon injection
 CE – Combustion Engineering
 FGD – flue gas desulfurization
 h-ESP – hot-side electrostatic precipitator
 ROFA™ – Rotating Opposed-Fire Air
 SEA – sorbent enhancement additive
 UND EERC – University of North Dakota Energy & Environmental Research Center
 W-bit. – western bituminous coal

ADA-ES Inc. – ADA Environmental Solutions Inc.
 COHPAC – compact hybrid particulate collector
 FW – Foster Wheeler
 NA – not available
 ROTAMIX™ – Rotating Mixing
 TBD – to be determined

B&W – Babcock & Wilcox Company
 c-ESP – cold-side electrostatic precipitator
 GE EER – GE Energy and Environmental Research
 PRB – Powder River Basin subbituminous coal
 SDA-FF – spray dryer absorber-fabric filter
 t-fired – tangentially fired
 URS – URS

MERCURY INFORMATION CLEARINGHOUSE

QUARTER 6 – MERCURY CONTROL FIELD DEMONSTRATIONS

INTRODUCTION

The Canadian Electricity Association (CEA) identified a need and contracted the Energy & Environmental Research Center (EERC) to create and maintain an information clearinghouse on global research and development activities related to mercury emissions from coal-fired electric utilities. With the support of the CEA, the Center for Air Toxic Metals[®] (CATM[®]) Affiliates, the U.S. Department of Energy (DOE), and the Canadian Council of Ministers of the Environment (CCME), the EERC is developing comprehensive quarterly information updates to provide a detailed assessment of advances in mercury monitoring, control, policy, and related research progress.

Ongoing developments in mercury regulations for coal-fired power plants in Canada in the form of Canada-Wide Standards (CWS) and the United States in the recently published U.S. Environmental Protection Agency's (EPA's) mercury rule illustrate the need for a solid understanding of mercury chemistry and effective mercury control strategies for coal-fired electric utilities.

In order to adequately address the many topics pertinent to mercury research and development and provide the detail necessary for the various stakeholders to make informed decisions, selected topics will be discussed in detail in each quarterly report. Issues related to mercury from coal-fired utilities include measurement, control, policy, and transformations. The discussion in this quarterly report will focus on the status and results of the many large-scale mercury control projects that are ongoing or recently completed. Specific topics that have been addressed in previous quarterly reports include the following:

Quarter 1 – Sorbent Control Technologies for Mercury Control

Quarter 2 – Mercury Measurement

Quarter 3 – Advanced and Developmental Mercury Control Technologies

Quarter 4 – Rerelease of Mercury from Coal Combustion By-Products

Quarter 5 – Mercury Fundamentals

Topics that will be addressed in upcoming quarterly reports include, but are not limited to, the following:

- Quarter 7 will provide a summary of the status of mercury regulations in the various states, provinces, and federal entities. Specifically, a review of the EPA final Utility

Clean Air Mercury Rule (CAMR) will be reviewed and presented in this quarterly. It will also include a summary of possible compliance strategies for utilities in the United States and impacts on state regulations and litigation.

- Quarter 8 will review commercialization aspects of mercury control technologies including warranties, phase-in, material supply, balance-of-plant impacts, and operational issues.
- Quarter 9 will be the final report and will summarize pertinent updates in areas presented in earlier quarterly reports. Additionally, it will summarize the status of the CEA mercury program, including data summaries from stack sampling, coal and ash analysis, and the laboratory round-robin. These results will be compared against program objectives.

MERCURY POLICY

The CCME has been developing a CWS for mercury since 1998 for several significant mercury-emitting sectors and products. Standards have been completed for base-metal smelters, incinerators, mercury-containing lamps, and dental amalgam wastes. A CWS announcement is scheduled in 2005 for mercury emissions from coal-fired electric power-generating plants, with implementations to begin in 2010. In anticipation of the 2005 CWS announcement, the Canadian coal-fired generating companies have embarked on a multiyear program to improve the mercury measurement and control information base. Data from this effort are still in verification and analysis by the CCME; however, preliminary results can be accessed in the program Web site: www.ceamercuryprogram.ca.

EPA issued the first CAMR on March 15, 2005, to permanently cap and reduce mercury emissions from coal-fired power plants (a power plant is defined as an electrical generating facility that provides >25 MWe). The CAMR is a two-phase market-based cap-and-trade program that will build on EPA's Clean Air Interstate Rule (CAIR), which was implemented to permanently cap emission of sulfur dioxide (SO₂) and nitrogen oxide (NO_x) in the eastern 28 states and the District of Columbia. The first phase of CAMR begins in 2010 and will cap Hg emissions at 38 tons per year from the current 48 tons, a 21% reduction. Phase 2 will be implemented in 2018 and will set the final cap at 15 tons, a reduction of 69%. It is expected that the initial phase of CAMR will be met as a cobenefit by the additional wet scrubbers and selective catalytic reduction (SCR) systems that will be installed to meet the CAIR. However, a cap of 15 tons will require additional mercury-specific controls at many power plants.

For trading purposes, EPA has established allocations for each state, the District of Columbia, and Indian reservations based on their share of the total heat input from coal. These were adjusted to reflect coal rank and existing air pollution control equipment. Mercury emission limit subcategorizations were developed for bituminous coal, subbituminous coal, lignite coal, coal refuse, as well as integrated gasification combined-cycle (IGCC) configurations and wet and dry scrubber systems when used at facilities burning subbituminous fuel. The total

2010–2017 state allocations are 38 tons of mercury emission, and from 2018 and thereafter, the state allocations are 15 tons of mercury emission. Each state will be free to decide if it wishes to participate in the trading program.

In addition to the cap-and-trade program, new coal-fired sources will have additional mercury requirements as part of the New Source Performance Standards. The requirements have been subcategorized as follows:

- Bituminous units – 21×10^{-6} lb/MWh
- Subbituminous units
 - Wet flue gas desulfurization (WFGD) – 42×10^{-6} lb/MWh
 - Dry FGD – 78×10^{-6} lb/MWh
- Lignite units – 145×10^{-6} lb/MWh
- IGCC units – 20×10^{-6} lb/MWh
- Coal refuse units – 1.4×10^{-6} lb/MWh

In addition to the CAMR, several states are in various stages of establishing state-specific regulations for mercury to further reduce mercury emissions. A more comprehensive review of the CAMR and of the status of state regulatory activities will be provided in the Quarter 7 report.

QUARTER 6 FOCUS: MERCURY CONTROL FIELD DEMONSTRATIONS

FIELD DEMONSTRATIONS COMPLETED

In 1999, the DOE National Energy Technology Laboratory (NETL) issued a request for proposal (RFP) to test mercury control technologies at the full scale. The near-term goal of the RFP was to evaluate technologies that could achieve 50%–70% mercury removal at a cost of less than three-quarters of the estimated cost of \$50,000–\$70,000/lb (Can\$136,000–Can\$191,000/kg) mercury removed. The longer-term goal was to develop technologies that could provide up to 90% control at a cost of half to three-quarters of activated carbon injection (ACI) technology by the year 2010. In September 2000, NETL announced an award to a team headed by ADA-ES to do full-scale testing of ACI at four power plants (1). A brief description of the plants and the month tested is provided in Table 1.

Table 1. Description of the Power Plant Tests by ADA-ES Using ACI

Company	Plant	Coal Rank	Configuration	Test Completed
Alabama Power	E.C. Gaston	Low-sulfur bit.	h-ESP ¹ and COHPAC TM	April 2001
WE Energies	Pleasant Prairie	PRB ²	c-ESP ³	November 2001
PG&E	Brayton Point	Low-sulfur bit.	c-ESP	August 2001
PG&E	Salem Harbor	Low-sulfur bit.	c-ESP SNCR ⁴	November 2002

¹ Hot-side electrostatic precipitator (h-ESP).

² Powder River Basin.

³ Cold-side ESP.

⁴ Selective noncatalytic reduction.

The testing at each of these facilities included parametric testing using several different commercially available powdered activated carbons (PACs) followed by a 1- to 2-week test using one of the PACs based on the parametric testing. The results of the tests are shown in Figure 1. As expected, the use of a fabric filter (FF) (high air-to-cloth ratio, COHPACTM) with ACI at the E.C. Gaston Station provided the best mercury removal at the lowest ACI rate, 87%–90% removal at an ACI rate of 1.5 lb/Macf. However, as a result of increased particulate loading to the COHPAC FF, the cleaning frequency increased significantly. For the same type of coal (low-sulfur bituminous), an ACI rate of 20 lb/Macf was needed at the Brayton Point Station (ESP alone) to obtain 90% mercury removal. At an ACI rate of 1.5 lb/Macf, only about 15% mercury removal was achieved at the Brayton Station. For the PRB coal with a c-ESP (Pleasant Prairie Station), the maximum mercury removal was 66% regardless of the ACI rate. However, at an ACI rate of 1.5 lb/Macf, mercury removal was ~40%.

The effect of temperature, unburned carbon (loss-on-ignition [LOI]), and an SNCR with and without ACI was evaluated at the Salem Harbor Station (2). With the SNCR online, an ESP inlet temperature of 295°F, and the plant at full load (86 MW), the LOI was 25%–35%, and the baseline mercury removal range was 87%–94%. When the SNCR was taken off-line, the

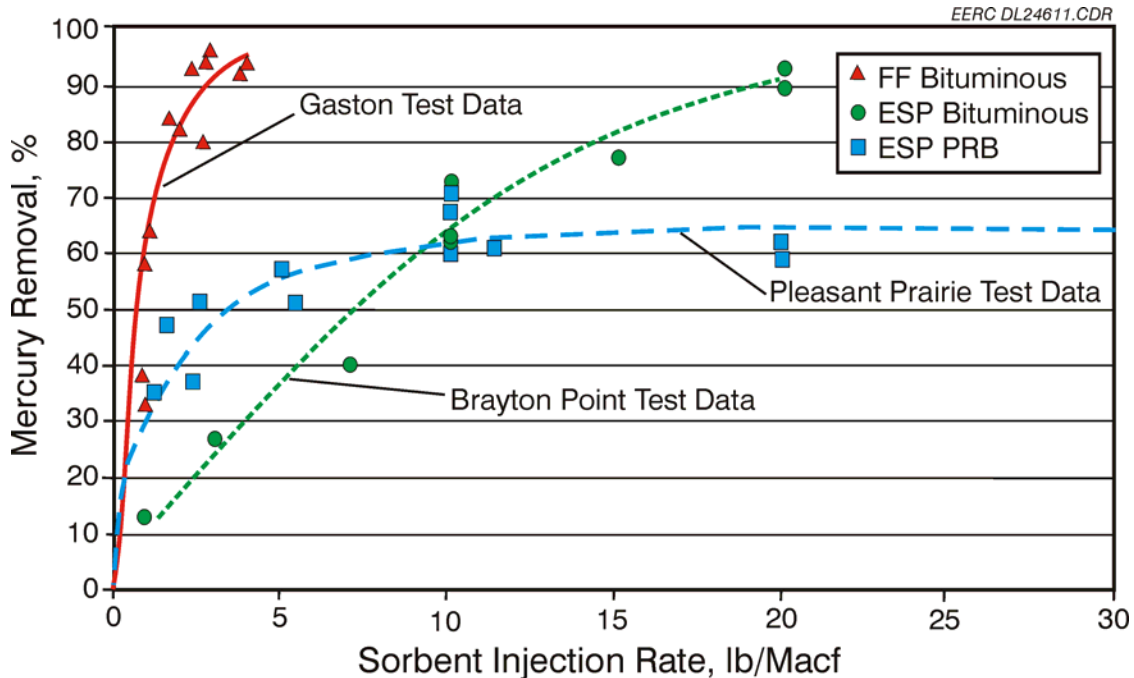


Figure 1. Mercury removal (%) vs. sorbent injection rate (lb/Macf) for tests at three sites.

baseline mercury removal was essentially unchanged, but the data were more variable. The results were similar when the LOI was decreased to 15%–20% by reducing the load to 65 MW. However, when the temperature at the ESP inlet was increased to 350°F, the baseline mercury removal decreased to only 5%–20%.

Prior to the tests with ACI, the Salem Harbor facility had switched to a lower-sulfur coal resulting in a lower baseline removal efficiency of about 47% at an ESP inlet temperature of 298°–306°F and less than 10% at 343°–347°F. At an ACI rate of 10 lb/Macf, the mercury removal increased to 82% for the lower temperature range compared to 65% at the higher temperatures.

With new requirements for additional SO₂ and NO_x control on existing power plants, it is expected in the next 5–10 years that a number of plants will be installing SCRs and WFGD systems. Based on field mercury measurements (3), it is possible that for these systems, 90% mercury control will be achieved without any sorbent or additional mercury controls. However, this appears to be true only when an eastern bituminous coal is fired. Mercury control is more problematic for western lower-rank fuels: lignites and subbituminous coals. In general, lignites and subbituminous coals contain significantly lower levels of chlorine and have a much higher concentration of alkali components compared to bituminous coals. As a result, most of the mercury generated is in the form of elemental mercury (Hg⁰), which is more difficult to remove. Therefore, the focus for mercury control research and testing in the last several years has been to develop mercury control technologies for low-rank fuels.

As a result, in 2003 and 2004, NETL issued three more RFPs to evaluate mercury control technologies through its Office of Fossil Energy's Innovation Program and through the Clean Coal Initiative with a focus on low-rank coals. A total of 11 projects were selected that involved ACI either as a primary control option or as a comparison for a novel control technology. The balance of this section summarizes additional demonstration projects that have been completed. Subsequent sections of this document summarize ongoing demonstration projects as well as projects that will begin in 2005.

Leland Olds Station – Basin Electric Power Cooperative

The EERC, in conjunction with Basin Electric Power Cooperative and NETL, completed a sorbent injection project in 2004 at the Leland Olds Station (LOS). LOS Unit 1 is a 220-MW Babcock and Wilcox (B&W) pulverized-coal wall-fired system. Twenty low-NO_x burners with overfire air are supported by ten feeders and pulverizers. The primary fuel is lignite coal from the Freedom Mine (North Dakota) with occasional blending with 30% PRB coal from the Dry Fork Mine (Wyoming). Particulate control is accomplished using two parallel ESPs manufactured by Joy. The specific collection area (SCA) for each ESP is 320 ft²/1000 acfm supported by four rows of hoppers with eight hoppers per row.

The testing completed at the LOS involved three phases: baseline, parametric, and monthlong testing. Specific activities focused on sorbent injection into one full-scale ESP. The sorbents used during this field demonstration included PAC as well as PAC with sorbent enhancement additives (SEA). ACI was upstream of the ESP, and the SEAs were added with the fuel. Project results were documented in a symposium paper entitled "Enhancing Carbon Reactivity for Mercury Control: Field Test Results from Leland Olds" and a symposium presentation entitled "Developing Mercury Control Options for Utilities Firing Western Fuels," respectively (4, 5).

The baseline testing showed that mercury removal across the ESP was 18%. The goal of the parametric testing was to obtain a minimum mercury removal rate of 55% with ACI and an SEA. After the optimization tests were completed and the mercury removal objective achieved, the monthlong test was initiated. The average mercury removal for the monthlong test was reported to be 63% based on an ACI rate of 3 lb/Macf and an SEA injection rate of 5 lb chlorine/Macf. In this case, the SEA was calcium chloride. The average flue gas mercury concentrations over the monthlong test were extrapolated to calculate a theoretical mercury emission rate of 2.04 lb/TBtu for the 220-MW unit. Based on the monthlong test, there were no significant impacts on plant operations. Special air-cooled corrosion probes, placed in the flue gas stream in the economizer and the inlet and outlet of the secondary airheater for 4 weeks showed no signs of abnormal deposition or corrosion as a result of the calcium chloride added with the fuel. Subsequent short-duration testing with a second SEA (unidentified) and an ACI rate of 3 lb/Macf demonstrated mercury removal rates as high as 80%. We are evaluating potential long-term impacts on plant operations, and a yearlong demonstration is under consideration.

Coal Creek Station – Great River Energy

ADA-ES Inc., in conjunction with Great River Energy, and EPRI completed an ACI project at Great River Energy's Coal Creek Station (CCS) near Underwood, North Dakota. Work was conducted on Unit 1 firing a North Dakota lignite. CCS Unit 1 is a 546-MW Combustion Engineering pulverized-coal (pc), tangentially fired system. Unit 1 particulate control is accomplished with a c-ESP manufactured by Wheelabrator-Frye Inc. The calculated SCA for the ESP is 599 ft²/1000 acfm. The ESP design includes six electrical fields, with an individual field length of approximately 12.5 feet in the direction of gas flow. Flue gas temperature at the ESP inlet ranges from 330° to 360°F, depending on boiler load. A WFGD system manufactured by Combustion Engineering is employed to control SO₂ emissions.

The TOXECON II™ concept involves injecting PAC within an ESP. For this project, PAC was injected between the third and fourth collecting fields of the ESP. The rationale for this approach was to permit the collection of a large percentage of the fly ash from the ESP hoppers prior to ACI to avoid carbon contamination of fly ash that can be marketed as a salable by-product. Mercury sampling occurred at the inlet and outlet of the ESP. Testing on Unit 1 at CCS was carried out in two phases, baseline and parametric testing. Two activated carbons were used during the parametric testing, DARCO FGD™ (NORIT) and CB 200xF™ (an iodine-impregnated sorbent derived from coconut shell, Calgon/Barnebey Sutcliffe). Baseline and parametric test results were documented in a symposium paper entitled “Full-Scale Evaluation of TOXECON II on a Lignite-Fired Boiler” and a separate symposium presentation entitled “Full-Scale Evaluations of Mercury Control Options for Western Fuels,” respectively (6, 7).

Baseline results over 2 days of testing averaged 7% mercury removal, with a range of 5%–20%. During 3 days of parametric testing with the DARCO FGD activated carbon, injection rates ranged from 1 to 15 lb/Macf. At injection rates of 1 and 3 lb/Macf, average mercury removal was 46% and 58%, respectively. Increasing the DARCO FGD injection rate to >5 lb/Macf resulted in a mercury removal rate of 70%. However, injection rates of 10 lb/Macf and higher did not appear to increase mercury removal.

Based on previous experience, the CB 200xF AC was expected to perform better than the DARCO FGD activated carbon. However, during a single day of parametric testing, the CB 200xF AC did not perform as well as the DARCO FGD AC for specific injection rates of 1, 3, and 10 lb/Macf. Two explanations were offered for the CB 200xF AC not performing up to expectations. First, the flue gas temperature regime for this project was higher, 350° to 360°F versus <225°F for previous SDA–FF tests. Therefore, the iodine likely volatilized from the carbon surface upon carbon particle injection and heating. Another potential contributing factor was particle size. Characterization of the DARCO FGD AC showed an average particle size of 19 µm versus 87 µm for the CB 200xF activated carbon. This difference in particle size dramatically impacts the number of particles and equivalent available surface area injected per unit mass.

Because of the short duration of these tests, balance-of-plant issues could not be practically evaluated. However, a number of observations were made. Although no increase in average stack opacity was observed during ACI tests with only 25% of the flue gas being treated, a 10% to 30% increase in rapping spike opacity was observed. Carbon was evident on the surface of the scrubber slurry during ACI tests, indicating that some activated carbon was passing through the ESP. Particulate sampling at the outlet of the ESP during baseline and ACI tests showed a 100% increase in the outlet mass loading when carbon was injected. An electrical short was experienced in the fifth field of the ESP after a period of ACI was completed. However, ACI was not occurring when the field tripped. Although the exact cause is uncertain, it may have resulted from carbon injection and tracking on the insulators. The use of purge blowers could effectively solve tracking problems if they were found to be persistent during long-term testing. Finally, LOI analyses of fly ash samples collected from the fourth field of the ESP during baseline and ACI tests showed that LOI values increased from 0.14 to 3.79 wt% as a result of ACI. In order to determine the commercial potential of the TOXECON II concept, further parametric testing will be necessary along with long-term testing to verify performance as well as potential balance-of-plant issues.

Endicott Station – Michigan South Central Power Agency

B&W, in conjunction with McDermott Technology, Inc. (MTI), Michigan South Central Power Agency (MSCPA), the Ohio Coal Development Office, and NETL, completed a WFGD mercury control project at MSCPA's Endicott Station located in Litchfield, Michigan. The project objective was 90% overall mercury removal at a 50% to 75% cost advantage when compared to ACI technology. Activities focused on evaluation of B&W-MTI's proprietary enhanced mercury removal concept for FGD systems. The concept employs a reagent additive to increase mercury removal across the FGD system and reduce reemission of mercury once it is captured in the FGD system. Project results were documented in a final project report entitled "Full-Scale Testing of Enhanced Mercury Control Technologies for Wet FGD Systems" (8).

Endicott Station is a single-unit, nominally 55-MW B&W Stirling boiler firing an Ohio bituminous coal. Particulate control is accomplished with a c-ESP manufactured by Belco, with a reported particulate removal efficiency of >98%. SO₂ control is accomplished using a single absorber B&W limestone wet scrubber. The SO₂ concentration at the inlet of the FGD system was reported to be nominally 3600 ppm. The liquid-to-gas ratio and slurry pH were reported to be 78 gal/1000 acf and 5.4–5.6, respectively. SO₂ removal is typically 92%. In situ forced oxidation is employed to produce a gypsum by-product for cement applications.

Work completed at the Endicott Station involved three phases: parametric, verification, and monthlong testing. Parametric testing was used to determine optimum process conditions followed by 2 weeks of verification testing to confirm the performance of the optimum process conditions selected. Long-term testing involved operation at optimum process conditions for a 4-month period to document mercury removal and demonstrate that there were no detrimental impacts on SO₂ removal, FGD system materials of construction, or by-product utilization.

Verification test results at the Endicott Station demonstrated an average total mercury removal rate of 76% across the FGD system, with an oxidized mercury removal rate of 96%. During the long-term test, average mercury removal across the FGD system increased to 79%. Results from both test periods demonstrated that most of the oxidized mercury present in the flue gas was removed in the WFGD system. In addition, sampling data showed no increase in flue gas elemental mercury concentration at the FGD system outlet sample location, demonstrating that mercury reemission was prevented.

Characterization of WFGD solids generated at the Endicott Station during this project determined that the captured mercury was associated with the fines in a stable form. This is a significant observation because the fines can be separated from the gypsum crystals using commercially available technology. Once separated, the mercury-containing fines can be placed in a standard landfill, and concerns with respect to mercury concentration in gypsum by-products, marketed in this case for cement applications, can be mitigated.

A cost comparison of the B&W–MTI proprietary process with ACI was presented for a 500-MW plant employing a c-ESP for particulate control and a combination of low- and high-sulfur fuels. For an existing plant with a WFGD system, a significant annual levelized cost (ALC) advantage was reported for the B&W–MTI process (0.18 mil/kWh) versus ACI (0.85 mil/kWh for 60% Hg removal). In the case of an existing plant without a WFGD system, an advantage was reported for the ACI technology (1.65 mil/kWh for 70% Hg removal) versus the B&W–MTI process (4.23 mil/kWh, including the cost of FGD technology). Reducing the mercury removal target to 60% results in a greater advantage for the ACI technology (0.85 mil/kWh) versus the B&W–MTI process (4.23 mil/kWh including the cost of FGD technology). A comparison of the B&W–MTI FGD technology (4.23 mil/kWh) versus the ACI SDA–FF technology (4.59 mil/kWh) shows an ALC advantage for the B&W–MTI FGD technology for 80% mercury removal.

Specific plans for future work were not discussed. However, the report stated that B&W was committed to the development and commercial application of mercury control technology for WFGD systems.

Zimmer Station – Cinergy

B&W, in conjunction with MTI, Cinergy, the Ohio Coal Development Office, and NETL, completed a WFGD mercury control project at Cinergy’s Zimmer Station located in Moscow, Ohio. The project objective was 90% overall mercury removal at a 50% to 75% cost advantage when compared to ACI technology. Activities focused on evaluation of B&W–MTI’s proprietary enhanced mercury removal concept for FGD systems. The concept employs a reagent additive to increase mercury removal across the FGD system and reduce reemission of mercury once it is captured in the FGD system. Project results were documented in a final project report entitled “Full-Scale Testing of Enhanced Mercury Control Technologies for Wet FGD Systems” (8).

Zimmer Station is a single-unit, nominally 1300-MW B&W Carolina-type universal pressure boiler firing an Ohio bituminous coal. Particulate control is accomplished with two c-ESPs manufactured by Flakt, with a reported particulate removal efficiency of 99.9%. SO₂

control is accomplished using six B&W absorber modules employing Thiosorbic[®], a magnesium-enhanced lime slurry reagent. The SO₂ concentration at the inlet of the FGD system was reported to be nominally 3300 ppm. Liquid-to-gas ratio and slurry pH were reported to be 21 gal/1000 acf and 5.8–6.0, respectively. SO₂ removal is typically 92%, but 95% can be achieved with five absorber modules. Ex situ forced oxidation is employed to produce a gypsum by-product for wallboard applications.

Work completed at the Zimmer Station only involved 2 weeks of verification testing to confirm the performance of the process conditions selected. The FGD slurry reagent additive was added to all operating absorber modules simultaneously. Verification test results at the Zimmer Station demonstrated an average total mercury removal rate of 51% across the FGD system, with an oxidized mercury removal rate of 87%. In addition, sampling data showed an increase in flue gas elemental mercury concentration at the FGD system outlet location, demonstrating that mercury reemission was not prevented. Increasing the reagent addition rate by 50% provided no improvement in mercury removal. Overall, these data demonstrate a lower level of performance when compared to the Endicott Station results.

Characterization of WFGD solids generated at the Zimmer Station during this project determined that the captured mercury was associated with the fines in a stable form, consistent with the Endicott Station observation. This is significant because the fines are separated from the gypsum crystals as a result of the ex situ oxidation at the Zimmer Station. Once separated, the mercury-containing fines can be placed in a standard landfill, and concerns with respect to mercury concentration in gypsum by-products, marketed in this case for wallboard applications, can be mitigated.

A cost comparison of the B&W–MTI proprietary process with ACI was presented for a 500-MW plant employing a c-ESP for particulate control and a combination of low and high-sulfur fuels. For an existing plant with a WFGD system, a significant advantage was reported for the B&W–MTI process (0.18 mil/kWh) versus ACI (0.85 mil/kWh for 60% Hg removal). In the case of an existing plant without a WFGD system, an advantage was reported for the ACI technology (1.65 mil/kWh for 70% Hg removal) versus the B&W–MTI process (4.23 mil/kWh including the cost of FGD technology). Reducing the mercury removal target to 60% results in a greater advantage for the ACI technology (0.85 mil/kWh) versus the B&W–MTI process (4.23 mil/kWh, including the cost of FGD technology). A comparison of the B&W–MTI FGD technology (4.23 mil/kWh) versus the ACI SDA–FF technology (4.59 mil/kWh) shows an advantage for the B&W–MTI FGD technology for 80% mercury removal.

E.C. Gaston Station – Alabama Power

Southern Company, in conjunction with Alabama Power, ADA-ES, Inc., EPRI, and NETL, completed a mercury control project at the E.C. Gaston Station using ACI in combination with a COHPAC system. The E.C. Gaston Station, located in Wilsonville, Alabama, has four 270-MW B&W balanced-draft coal-fired boilers and one Combustion Engineering 880-MW forced-draft coal-fired boiler. All units fire a variety of low-sulfur, washed, eastern bituminous coals. The primary particulate control equipment on all units is h-ESPs. Units 1 and 2 and Units 3 and 4 share common stacks. In 1996, Alabama Power contracted with Hamon Research-Cottrell to

install a COHPAC system downstream of the h-ESP (274 ft²/1000 acfm, Research-Cottrell) on Unit 3. This COHPAC system was designed to maintain Unit 3 and 4's stack opacity levels below 5% on a 6-minute average.

The COHPAC system is a hybrid pulse-jet baghouse, designed in this case to treat flue gas volumes of 1,070,000 acfm at 290°F (gross air-to-cloth ratio of 8.5 ft/min with online cleaning). This COHPAC baghouse consists of four isolatable compartments—two compartments per air preheater identified as either A- or B-side. Each compartment consists of two bag bundles, each bundle consisting of 544 bags for a total of 1088 bags per compartment, or 2176 bags per casing. The bags were 23-foot-long polyphenylene sulfide (PPS) felt filter bags, 18-oz/yd² nominal weights. The ACI evaluation was conducted on one-half of the gas stream, nominally 135 MW. The B-side was chosen for testing. The A-side was monitored as the control.

The work plan for the E.C. Gaston Station included baseline, optimization, and long-term testing. Baseline testing documented baseline mercury removal rates. Optimization testing established a carbon injection scheme that achieved the highest mercury removal rate within the operational limits of the system. Long-term testing was split into two 6-month periods: one 6-month period with old bags and a second 6-month period with new bags. Project results were documented in two symposium papers entitled “Field Test Program for Long-Term Operation of a COHPAC System for Removing Mercury from Coal-Fired Flue Gas” and “Long-Term Operation of a COHPAC System for Removing Mercury from Coal-Fired Flue Gas,” respectively (9, 10).

The baseline testing indicated that the COHPAC bag-cleaning frequency was much higher than expected, exceeding the targeted maximum allowable cleaning frequency of 1.5 pulses/bag/hour (p/b/h) that was used during a 2-week test in 2001. There were times when the COHPAC bags were cleaning continuously at 4.4 p/b/h. The baseline mercury removal rates ranged from 0% to 90% depending on inlet particulate mass loading. The reason given for the large range was that the particulate mass loading entering the COHPAC system greatly exceeded design capacity.

Because of the frequent bag cleaning observed during baseline tests, ACI rates during the optimization tests were severely limited in order to avoid cleaning frequency problems and still achieve reasonable mercury removal. Based on the optimization tests, the following ACI rates were selected: 1) when the COHPAC baghouse inlet mass loading was <0.07 gr/acf, the carbon injection rate was set to either 16 or 20 lb/h (0.52 or 0.66 lb/Macf); 2) when inlet mass loading was higher, between 0.07 and 0.14 gr/acf, the carbon injection rate was reduced to 10 lb/h (0.35 lb/Macf); and 3) when the inlet mass loading was >0.14 gr/acf, the COHPAC baghouse was often in a state of continuous cleaning, and ACI was discontinued.

Long-term testing with the old bags (2.7 denier) was conducted for 6 months using the ACI optimization parameters previously discussed. During this period, the average mercury removal rate was 86% for full-load operation. Average inlet and outlet mercury concentrations for the 6-month period were 14.3 and 2.1 µg/Nm³, respectively. Nominal daily average inlet and outlet mercury concentrations varied from 5.1 to 25.6 µg/Nm³ and 0.24–6.2 µg/Nm³,

respectively. Reducing boiler load by 28% and the corresponding flue gas flow rate and COHPAC baghouse air-to-cloth ratio resulted in 95% mercury removal for an ACI rate of 45 lb/hr, or 2.0 lb/Macf.

Following installation of new bags (7 denier), baseline and optimization tests were repeated. The symposium papers referenced for this work did not contain final results for the second 6-month test period. However, preliminary results were reported. Preliminary data demonstrated that an ACI rate of 45 lb/hr (1.3 lb/Macf) resulted in an average of 92% mercury removal. Maximum and minimum hourly values were 98% and 80%, respectively.

The only significant balance-of-plant issue identified was bag-cleaning frequency. Specifically, the older bags had to be cleaned more frequently than the newer bags. Eight carbon types were selected for testing in June–August 2004, including carbon from CARBOCHEM, Superior Adsorbent, General Technologies, Donau, NORIT, and RWE. Final data from these tests and the second 6-month test period were expected to be available in 2004, but were not available for inclusion in this summary.

Cape Fear Station – Progress Energy Carolinas

Mobotec USA, in conjunction with Progress Energy Carolinas, NETL, and other organizations, completed a multipollutant (including mercury) control project at the Cape Fear Station. The approach involved a combination of furnace sorbent injection (FSI) with rotating opposed fire air (ROFA™) and rotating mixing (ROTAMIX™) systems. The Cape Fear Station, located in Moncure, North Carolina, has two Combustion Engineering tangentially fired boilers: Unit 5, nominally 154 MW, and Unit 6, nominally 174 MW. Both units fire a low-sulfur bituminous coal. The primary particulate control equipment on both units is a c-ESP originally manufactured by Buell with a nominal SCA of 300 ft²/1000 acfm. Unit 5 operated at 75% load, nominally 100 MW, during the sorbent injection tests.

The purpose for installing the ROFA and ROTAMIX systems in conjunction with FSI was multipollutant control, specifically SO₂, NO_x, HCl, and mercury. The sorbents used included limestone and trona. ROFA is a combustion air distribution and mixing technology intended to improve combustion and reduce NO_x emissions. ROTAMIX combines SNCR chemistry with FSI, making use of the ROFA air distribution system. The test plan for work at the Cape Fear Station included baseline, some optimization, and short-term performance tests. Project results were documented in a symposium paper entitled “Full-Scale Evaluation of a Multi-Pollutant Reduction Technology: SO₂, Hg, and NO_x” (11).

Baseline sampling documented SO₂, SO₃, NO_x, HCl, and mercury concentrations at the stack. Total mercury concentrations ranged from 10.54 to 11.31 µg/Nm³. Speciation data indicated that particulate, oxidized, and elemental mercury concentrations were 0.01 to 0.10 µg/Nm³, 7.95 to 8.16 µg/Nm³, and 2.50 to 3.14 µg/Nm³, respectively. Optimization tests were conducted by injecting each sorbent material at multiple elevations during an 8-hr period to determine the best location. Subsequent short-term (4-hr) performance tests involved

injecting each sorbent at selected locations using alkali-to-sulfur molar ratios of 2:1 and 3:1. During the short-term performance tests, sampling documented SO₂, SO₃, and mercury emissions at the stack for comparison with the baseline data.

During the short-term limestone and trona injection tests, total mercury concentrations at the stack were reduced by nearly 90% and 67%, respectively. Total mercury concentrations in the stack during the limestone injection tests ranged from 1.12 to 1.18 µg/Nm³, with particulate, oxidized, and elemental mercury concentrations of 0.01–0.18 µg/Nm³, 0.90–1.04 µg/Nm³, and 0.07–0.09 µg/Nm³, respectively. Total mercury concentrations in the stack during the trona injection tests ranged from 3.54 to 3.65 µg/Nm³, with particulate, oxidized, and elemental mercury concentrations of 0.04–0.11 µg/Nm³, 2.07–2.15 µg/Nm³, and 1.28–1.54 µg/Nm³, respectively. Although the paper did not discuss a rationale for the mercury removal reported, the mercury speciation data indicate that oxidized and elemental mercury observed at the stack during baseline sampling were converted to particulate mercury and captured in the ESP.

The only significant balance-of-plant issue identified was severe slagging in the superheater, requiring Unit 5 to be shut down for slag removal. The severe slagging was attributed to the injection of limestone as an initiator, with trona injection compounding the problem. Because of the short duration of these injection tests, the degree of slagging observed is a serious operational problem. After the test was concluded, one key sootblower on Unit 5 was found to be inoperative. In addition to sootblowing, in order to mitigate the slagging problem observed, it is likely that sorbent injection must be moved to a lower-temperature regime in the furnace.

Future demonstration tests with the ROFA and ROTAMIX technology systems employing FSI are anticipated. Near-term plans include a demonstration test at the Richmond Power and Light Whitewater Station beginning in March 2005 (12).

FIELD DEMONSTRATIONS IN PROGRESS

Plant Yates – Georgia Power

URS, in conjunction with Southern Company, Georgia Power, ADA-ES, Inc., EPRI, and NETL, is conducting a mercury control project at Plant Yates, located in Newnan, Georgia. Sorbent injection tests have been conducted on both Units 1 and 2. Plant Yates Units 1 and 2 are 100-MW Combustion Engineering wet-bottom tangentially fired systems. Both units fire a low-sulfur bituminous coal and employ ESPs for particulate control. Unit 2 also employs dual flue gas conditioning (sulfur trioxide and ammonia injection) to enhance ESP performance. Unit 1 is equipped with a Chiyoda Thoroughbred-121 FGD system with a single-jet bubbling reactor (JBR) downstream of the ESP for SO₂ control. Unit 2 is not equipped with an SO₂ control system.

The testing completed at Plant Yates involved injection of three different sorbent types on each unit, DARCO FGD, Super HOK™, and NH carbon. Project results were documented in a

symposium paper entitled “Sorbent Injection for Mercury Control Upstream of Small-SCA ESPs” (13).

Unit 1 baseline results (without sorbent injection) were 34% mercury removal for an average ESP inlet mercury concentration of $4.02 \mu\text{g}/\text{Nm}^3$ and an average ESP outlet concentration of $2.64 \mu\text{g}/\text{Nm}^3$ (corrected to 3% O_2). Unit 2 baseline results were similar, 36% mercury removal for average ESP inlet and outlet mercury concentrations of $6.04 \mu\text{g}/\text{Nm}^3$ and $3.89 \mu\text{g}/\text{Nm}^3$, respectively. The fly ash had a high LOI content, typically in the 9–13 wt% range for both units.

Similar mercury removal trends were observed for all three sorbent types when injected into Unit 1. Specifically, the mercury removal rate leveled off between 50% and 70% for sorbent injection rates $>6 \text{ lb}/\text{Macf}$. Graphical depictions of the data showed that the NH carbon and the DARCO FGD data sets were nearly identical and the HOK curve was slightly lower. For the Unit 2 sorbent injection tests, the mercury removal levels out near 70% for sorbent injection rates of $6 \text{ lb}/\text{Macf}$ and above. When the DARCO FGD sorbent was injected, a maximum mercury removal rate of 70% was observed at a sorbent injection rate of $2 \text{ lb}/\text{Macf}$. Increasing the DARCO FGD sorbent injection rate to $13 \text{ lb}/\text{Macf}$ did not result in an increase in mercury removal.

Based on the tests completed, sorbent injection did not significantly affect the operation of the ESPs; however, results from longer-term testing have not yet been reported.

St. Clair Station – DTE Energy

DTE Energy, in conjunction with Sorbent Technologies Corporation and NETL, conducted a sorbent injection project at the St. Clair Station. The St. Clair Station has six boilers, four nearly identical 160-MW B&W wall-fired units and two Combustion Engineering tangentially fired boilers rated at nominally 350 MW and 540 MW, respectively. The flue gas from each of the four wall-fired boilers splits into two ducts to pass through one of eight parallel Wheelabrator-Frye c-ESPs. The sorbent injection tests were conducted on Unit No. 1 upstream of an 80-MW-equivalent ESP. The ESP used in support of this project has six fields and an SCA of $700 \text{ ft}^2/1000 \text{ acfm}$. However, in practice, the first field is not energized. Flue gas temperature at the sorbent injection point was about 335°F at full load. Vapor-phase mercury species in the flue gas, both total and elemental, were continuously measured upstream of the sorbent injection point and downstream of the ESP. Although the St. Clair Station typically fires a blend of 85% subbituminous coal and 15% bituminous coal, some testing while firing 100% subbituminous coal was planned.

Testing conducted at the St. Clair Station was carried out in three phases: baseline, parametric, and long-term testing using B-PAC™ activated carbon. This activated carbon is bromine-impregnated and intended to be compatible with fly ash use in concrete. Baseline and parametric testing results were documented in a symposium paper entitled “Full-Scale Mercury Sorbent Injection Testing at DTE Energy’s St. Clair Station” (14). Long-term testing, defined as

24 hr per day for a 30-day period, has been completed but results were not reported in the symposium paper.

Results of the baseline testing indicated that the mercury removal across the ESP varied between 0% and 40%. Preliminary parametric test results indicated that a sorbent injection rate of 2 lb/Macf resulted in a 50% reduction in total mercury emissions beyond the baseline observations. Therefore, overall mercury removal (baseline + sorbent injection) was 60%. Although testing at the St. Clair Station has been completed, final results for the parametric and long-term testing activities were not available for inclusion in this discussion. In addition, information concerning balance-of-plant issues was not available.

Following completion of the sorbent injection testing at the St. Clair Station, Sorbent Technologies Corporation planned to move the test equipment to Duke Energy's Buck Station in North Carolina for additional full-scale sorbent injection trials. Buck Station fires low-sulfur bituminous coal. Particulate control for the unit selected employs a h-ESP that operates at 700°F. Testing at the Buck Station was scheduled for the winter of 2004–2005.

Holcomb Station – Sunflower Electric Power Corporation

ADA Environmental Solutions Inc., in conjunction with Sunflower Electric Power Corporation, NETL, and EPRI, is conducting an ACI project at Sunflower Electric Power Corporation's Holcomb Station. The Holcomb Station is located near Garden City, Kansas. The unit being used in support of this project is a load-following, subcritical, 360-MW pc-fired system. The B&W opposed-fired Carolina-type radiant boiler was designed to burn PRB coal. SO₂ and particulate emission control is accomplished with three SDA modules supplied by Niro Joy Western, followed by two very low-A/C ratio reverse-air FFs, supplied by Joy Western.

The project at the Holcomb Station involved five phases: 1) baseline testing, 2) coal blending, 3) sorbent screening, 4) parametric testing, and 5) long-term tests. As many as five different coals were expected to be fired during the test program. However, Jacobs Ranch (mine located near Gillette, Wyoming) and Black Thunder (mine located near Wright, Wyoming) were fired during the baseline, coal blending, and parametric tests. Project results were documented in two symposium papers with the same titles, "Full-Scale Evaluation of Mercury Control by Injecting Activated Carbon Upstream of a Spray Dryer and Fabric Filter," and different primary authors (15, 16).

Baseline tests were conducted firing 100% PRB. Resulting mercury removal rates varied from –3% to 23% across the SDA–FF. Coal-blending tests involved blending a western bituminous coal from the West Elk Mine with a PRB subbituminous coal in an attempt to improve upon the baseline mercury removal observed. Graphical data presented in the paper indicated that an unspecified (1.5x) blend ratio of bituminous to subbituminous coal resulted in 50% mercury removal. Increasing the unspecified blend ratio to 3x resulted in 76% mercury removal. Sorbent screening tests evaluated 20 sorbents from ten vendors. Based on the screening tests, three activated carbons were selected for parametric testing.

The three activated carbons selected for parametric testing were identified as FGD-E3 (NORIT), 208CP (Calgon), and DARCO FGD (NORIT). Each of the activated carbons was tested for a period of 4 to 7 hr. Data showed that the 208CP and DARCO FGD activated carbons resulted in similar levels of mercury removal, 50% and 54%, respectively, for a sorbent injection rate of 1.0 lb/Macf. The activated carbon identified as FGD-E3 demonstrated the best performance, resulting in 77% mercury removal at an injection rate of 0.7 lb/Macf.

A proprietary chemical additive, ALSTOM's KNX, was added to the coal at the crusher house to increase the halogen concentration in the flue gas in an attempt to improve mercury capture. Application of the additive to the coal for a 48-hr period significantly changed the speciation of the mercury at the outlet of the air preheater. Specifically, the percentage of elemental mercury was reduced from 70%–90% to 20%–30%. However, no change in mercury removal across the SDA–FF system was observed. Also, at the FF outlet, the percentage of elemental mercury was 80%, only marginally lower than the 90% elemental mercury observed during baseline sampling. Two potential explanations were offered concerning these results: 1) the chemical additive resulted in a sampling artifact at the air preheater outlet or 2) oxidized mercury was reduced to elemental mercury across the SDA–FF system. The EERC believes the potential for the chemical additive to result in a sampling artifact is more likely than the reduction of oxidized mercury across the SDA–FF system. Although the reduction of mercury species has been widely shown in WFGD systems, it is not commonly expected in dry systems.

Simultaneous injection of the DARCO FGD activated carbon upstream of the SDA–FF system and addition of the KNX chemical additive to the coal resulted in 86% mercury removal compared to 54% mercury removal with DARCO FGD injection alone. These data indicate that the use of a fuel additive to increase the flue gas halogen concentration in conjunction with ACI can significantly increase mercury removal rates.

Based on the results from parametric testing, the FGD-E3 activated carbon was selected for use during 30 days of continuous injection. Results from this long-term testing showed an average mercury removal of 93% for an ACI rate of 1.2 lb/Macf. The corresponding outlet flue gas mercury concentration was 1.13 $\mu\text{g}/\text{Nm}^3$. Balance of plant issues were not discussed in the references cited. Sample and data analysis are ongoing for this site demonstration.

Plans for subsequent work include four additional sites: 1) AmerenEU's Meramec Station, 2) Missouri Basin Power Project's Laramie River Station, 3) Detroit Edison's Monroe Station, and 4) American Electric Power's Conesville Station. Brief summaries concerning these site demonstrations are included later in this report.

Meramec Station – AmerenEU

ADA Environmental Solutions, Inc., in conjunction with AmerenEU, NETL, EPRI, and other organizations, is conducting an ACI project at AmerenEU Meramec Station Unit 2 at St. Louis, Missouri. Unit 2 is a load-following, 140-MW pc-fired system. The boiler fires 100% PRB coal from multiple mines for compliance with SO₂ emission limits. Particulate emission control is accomplished with a c-ESP manufactured by American Air Filter with an SCA of

320 ft²/1000 acfm. The demonstration test was conducted on a flue gas volume representing a nominal capacity of 70 MW. Project results through December 31, 2004, were documented in a Quarterly Technical Report entitled “Evaluation of Sorbent Injection for Mercury Control” (17).

The project at the Meramec Station involved three phases: baseline, parametric, and long-term testing. Baseline tests were conducted firing 100% PRB from several sources. Initial mercury sampling data showed average ESP inlet and outlet mercury concentrations were 8.5 and 6.8 µg/dNm³, respectively, indicating 20% mercury removal. Generally, baseline mercury removal rates ranged from 15% to 18% across the ESP.

Two activated carbons were selected for parametric testing, DARCO Hg (previously referred to as DARCO FGD) (NORIT) and DARCO Hg-LH (previously referred to as DARCO FGD-E3) (NORIT), as well as the use of a fuel additive. Data showed that the DARCO Hg activated carbon resulted in 72% mercury removal for an injection rate of 5 lb/Macf. No improvement in mercury removal was observed for increased carbon injection rates as high as 20 lb/Macf. Similar to other tests involving low-rank fuels, increasing the carbon injection rate beyond a certain value does not result in further mercury removal because of the limited halogen concentration in the fuel.

DARCO Hg-LH is a brominated activated carbon. Chemically treated carbons have been shown to increase mercury removal when compared to untreated carbons. Data from the parametric testing showed that the DARCO Hg-LH carbon resulted in at least 91% mercury removal at an injection rate of 3.2 lb/Macf. This represents a nominal 26% increase in mercury removal for the DARCO Hg-LH versus DARCO Hg carbon at a 36% lower carbon injection rate.

KNX was added to the coal to increase the halogen concentration in the flue gas in an attempt to improve mercury capture with and without carbon injection. Because of changes in mill operation, LOI values were higher during these tests and likely increased the observed mercury removal somewhat. However, the addition of the KNX to the fuel increased mercury removal from 22%–34% to 57%–64% without any carbon addition. When KNX additive was injected with the fuel and the DARCO Hg carbon at the inlet of the ESP, vapor-phase mercury removal was 87%. Indirectly accounting for particulate mercury indicated total mercury removal was 95% for a DARCO Hg carbon injection rate of 5 lb/Macf. These data indicate that the use of a fuel additive to increase the flue gas halogen concentration with and without the injection of an activated carbon can significantly increase mercury removal rates.

Based on the results from parametric testing, the DARCO Hg-LH activated carbon was selected for use during long-term testing. The long-term testing aimed to demonstrate 60%–70% mercury removal with no impact on ash sales and show 85%–95% mercury removal. Data from a 5-day test demonstrated that a carbon injection rate of nominally 1.0 lb/Macf resulted in 60%–70% vapor-phase mercury removal across the ESP.

Injection of the DARCO Hg-LH activated carbon during a 30-day period demonstrated >90% mercury removal across the ESP. A carbon injection rate of 4.5 lb/Macf was initially required to achieve 90% vapor-phase mercury removal across the ESP. However, after 4 days,

the injection rate was reduced to 3 lb/Macf while maintaining the mercury removal objective. Based on mercury continuous emission monitor (CEM) data, vapor-phase mercury removal averaged 93% for an average carbon injection rate of 3.3 lb/Macf. ESP inlet and outlet mercury concentrations averaged 5.98 and 0.44 lb/Tbtu, respectively. Ontario Hydro sampling supported the CEM data.

The high overall mercury removal observed during this demonstration project may have been influenced to some degree by site-specific characteristics. Specifically, the 30% particulate-phase mercury observed at the ESP inlet was higher than typically observed for a PRB coal-fired system. This was attributed to the higher-than-expected LOI carbon in the ash and the high-surface-area tubular air preheater.

Balance-of-plant issues were discussed with respect to ESP performance and ash sales. No increase in stack opacity was observed during the 35 days of carbon injection at the inlet of the Unit 2 ESP. However, problems with ESP data acquisition during the long-term testing made it difficult to determine the impact of carbon injection on ESP operating parameters. Longer-duration testing was recommended for an ESP with a smaller SCA to conclusively document potential impacts on ESP performance.

Although carbon injection at a low rate (1 lb/Macf) resulted in a small increase in the ash carbon content (0.4%), previous work has shown that ash quality for concrete applications is negatively impacted by even trace amounts of activated carbon. Therefore, the ash is not expected to be salable for cement applications even at the low carbon injection rates. Segregation of the injected carbon and ash would be required to maintain ash sales. Segregation options identified for consideration included TOXECON and TOXECON II.

Sample and data analysis are ongoing for this site demonstration. Final results are expected to be addressed in a site report to be completed in September 2005. Plans for subsequent work include three additional sites: 1) Missouri Basin Power Project's Laramie River Station, 2) Detroit Edison's Monroe Station, and 3) American Electric Power's Conesville Station.

Laramie River Station – Missouri Basin Power Project

ADA-ES, Inc., in conjunction with Missouri Basin Power Project, NETL, and other organizations, will be conducting a sorbent injection project at Missouri Basin Power Project's Laramie River Station during the first quarter of 2005. Work will be conducted on Unit 3 firing a PRB coal. Laramie River Station Unit 3 is a nominal 550-MW B&W boiler. SO₂ and particulate control is accomplished with a B&W SDA-ESP combination. The ESP has an SCA of 599 ft²/1000 acfm. The demonstration test will be conducted on a flue gas volume representing a nominal capacity of 140 MW.

The test plan for work at the Laramie River Station involves short-term parametric tests. Specifically, two carbon-based sorbents will be injected into the flue gas at the inlet of the SDA. The sorbents selected were DARCO Hg and DARCO Hg-LH. Test plans also include coal

blending (PRB and western bituminous coal) tests and the use of KNX. Plans for this project were briefly addressed in a Quarterly Technical Report entitled “Evaluation of Sorbent Injection for Mercury Control” (17).

Stanton Station – Great River Energy

URS, in conjunction with Apogee Scientific, Great River Energy, ADA-ES, Inc., NETL, and EPRI, is conducting an ACI project at Great River Energy’s Stanton Station. Work is being conducted on both Unit 1 firing subbituminous coal and Unit 10 firing North Dakota lignite. Stanton Station Unit 1 is a 150-MW Foster Wheeler pc wall-fired system with low-NO_x burners. Unit 1 particulate control is accomplished with a Research-Cottrell c-ESP, and no FGD technology is employed. Unit 10 is a 60-MW Combustion Engineering pulverized coal tangentially fired system with low-NO_x burners. Particulate and SO₂ emissions are controlled using a Research-Cottrell SDA–FF.

The work plan for the Stanton Station included three phases: baseline, parametric, and monthlong testing. Specifically, activated carbon sorbents were to be injected into the flue gas stream at the inlet of the ESP on Unit 1 and the inlet of the SDA–FF on Unit 10. Project results for Unit 10 were documented in a symposium paper entitled “Full-Scale ACI for Mercury Control in Flue Gas Derived from North Dakota Lignite” (18).

Unit 10 baseline test results showed total vapor-phase mercury concentration ranging from 7.5 to 13 µg/Nm³. Speciation data indicated that <10% of the total mercury was in an oxidized form. Consistent with the speciation data, mercury removal across the SDA–FF was <10% during baseline test periods.

Unit 10 parametric testing included evaluation of six sorbents: 1) DARCO FGD (\$0.50/lb), 2) CB 200xF BS IAC (iodated coconut shell, \$7.71/lb), 3) FGD-E1 (chemically treated, \$0.60/lb), 4) FGD-E3 (halogenated, \$0.65/lb), 5) 208CP BS SAC (superactivated coconut shell, \$0.85/lb), and 6) ST BAC (brominated, \$0.50–1.00/lb). The flue gas temperature range for the SDA–FF system was 175° to 184°F. Results from the parametric testing demonstrated that the NORIT DARCO FGD AC achieved 75% mercury removal at an injection rate of 6.0 lb/Macf, while the Barnebey Sutcliffe 208CP BS SAC achieved almost 60% mercury removal at an injection rate of 1.5 lb/Macf. Chemically treated carbons performed significantly better than the nonchemically treated carbons. Specifically, at an injection rate of 1.0 lb/Macf, both the DARCO Hg-LH and Sorbent Technologies ST BAC demonstrated mercury removal rates of >85%. At an ACI rate of 1.5 lb/Macf, mercury removal rates of >90% were observed for the FGD-E3 and ST BAC materials. The Barnebey Sutcliffe CB 200xF BS IAC AC did not produce 90+% mercury removal as anticipated based on previous experience. The reason for the CB 200xF BS IAC not performing up to expectations is believed to be related to particle size. Characterization of samples of the CB 200xF BS IAC used in support of this project indicated an average particle size of 87 versus 47 µm for a sample retained from tests completed previously.

Based on the parametric testing results, extended testing was completed with the NORIT FGD-E3 activated carbon for a duration of 24 days. The performance objective for the testing was 60%–75% mercury removal across the SDA–FF. Results demonstrated that an ACI rate of

1.0 lb/Macf was needed to achieve 65%–75% mercury removal. The lower mercury removal rate observed during the extended testing is believed to be related to the higher sulfur concentration when compared to parametric tests.

Based on the testing completed on Unit 10, neither the sorbent injection rate nor the sorbent type affected the FF cleaning frequency. Also, no noticeable differences were observed in the operation of the spray dryer system during the baseline tests or the ACI tests. Future activities will focus on completion of planned project testing on Unit 1 firing a subbituminous coal.

Poplar River Power Station – SaskPower

The EERC, in conjunction with SaskPower, NETL, EPRI, the North Dakota Industrial Commission, ALSTOM, and a consortium of lignite-burning utilities and mining companies in Canada and the United States, is conducting a sorbent injection project at SaskPower's Poplar River Power Station. Work is being conducted on a pilot-scale slipstream system connected to Poplar River Power Station Units 1 and 2, which fire Poplar River lignite. Units 1 and 2 are nominally 300 MW. Unit 1 is a Combustion Engineering tangentially fired boiler with six mills. Unit 2 is a B&W opposed wall-fired pc boiler with six mills. Particulate control is accomplished with c-ESPs. Unit 1 was manufactured by Lodge-Cottrell, with an SCA of 412 ft²/1000 acfm and a design efficiency of 99.6%. Unit 2 was manufactured by American Air Filter, with an SCA of 400 ft²/1000 acfm and a design efficiency of 99.5%.

The slipstream system includes two FFs in series. The purpose of the first FF is to remove fly ash from the flue gas stream prior to the second FF if desired. The second FF can operate at air-to-cloth ratios of 2 to 8 ft/min and flue gas temperatures of 212° to 392°F. Piping arrangements allow the first FF to be partially or completely bypassed, and the flue gas source can be selected from one of four locations: 1) Unit 1 furnace, 2) Unit 1 secondary air heater, 3) Unit 1 secondary air heater ESP, or 4) Unit 2 secondary air heater ESP. A water-based gas cooler is also available to control flue gas temperature at the inlet of the second FF. A loss-in-weight feeder supports a pneumatic conveying system for sorbent injection at the inlet of the second FF. Two CEMs were installed to permit simultaneous sampling upstream of the sorbent injection location and downstream of the second FF.

Luscar char was one of several activated carbons selected for use during the slipstream system tests. The basis for the Luscar char selection as the initial sorbent was a series of bench-scale and pilot-scale tests completed at the EERC prior to initiating the work at Poplar River Power Station (19). Particulate control device configurations included c-ESP, FF, ESP–FF (referred to as COHPAC in the United States and TOXECON when a sorbent is added between the two), and the *Advanced Hybrid*TM filter.

Variables evaluated in the previous bench- and pilot-scale tests included the following:

- Two lignites, one from the Freedom Mine in North Dakota and the other from the Poplar River Mine in Saskatchewan.

- Two carbon-based sorbents, activated Luscar char (Bienfait) and DARCO FGD. These were selected based on sorbent-screening results (reactivity and capacity), physical properties (particle size and surface area), cost, and consensus among project sponsors. The Luscar char was thermally activated at the EERC at 1472°C.
- ACI temperature, 300° and 400°F.
- PAC particle size, standard and fine (mass median diameters of 20 and 5 µm).

Results from the previous bench- and pilot-scale tests demonstrated the following:

- Based on bench-scale test results, activated Luscar char and DARCO FGD were much more effective in capturing mercury compared to other sorbents tested.
- The mercury speciation data for the two test fuels, Poplar River and Freedom lignite, were nearly identical, 85% Hg⁰, 15% Hg²⁺, and <1% particulate-bound mercury.
- Total flue gas mercury concentration was higher when the Poplar River lignite was fired, as expected, based on the mercury concentration in the coals, 0.077 mg/kg for the Freedom lignite and 0.153 mg/kg for the Poplar River lignite. Chloride concentration was very low in both fuels, <20 ppm.
- In all four control devices tested, increasing activated Luscar char and DARCO FGD injection rates and decreasing flue gas temperatures significantly improved mercury removal for both the Poplar River and Freedom fuels.
- Generally, the activated Luscar char and DARCO FGD were slightly more effective at capturing mercury when Freedom lignite was fired relative to the Poplar River lignite.
- In a few cases, the DARCO FGD provided better mercury capture at a given injection rate relative to activated Luscar char. However, the conditions under which the Luscar char was activated have not been optimized.
- Four control technologies were tested with ACI: 1) ESP–FF (TOXECON in the United States), 2) the *Advanced Hybrid* filter, 3) FF, and 4) ESP, with the performance varying somewhat depending on fuel and sorbent injection method.
- The pilot-scale results for lignite firing showed that higher ACI rates were required to achieve similar mercury removal levels when compared to full-scale data for eastern bituminous coals.

Slipstream system project activities will include evaluation of several sorbent materials (carbons with enhanced activity and lower-cost activated carbons) at various injection rates, flue gas temperature effects, carbon injection between an ESP and an FF, carbon injection between two FFs, FF air-to-cloth ratio effects, fly ash-loading effects, carbon regeneration and recycle, and process modifications to improve carbon utilization (20). Slipstream pilot-scale tests are

currently under way at SaskPower's Poplar River Power Station, and some results are expected to be available by the second quarter of 2005. Based on the pilot-scale data, including plans for long-term testing (up to 1 year), estimates of full-scale technology costs and performance will be developed.

FUTURE FIELD DEMONSTRATIONS

Stanton Station – Great River Energy

The EERC, in conjunction with Great River Energy and NETL, will be conducting a sorbent injection project in 2005 at Great River Energy's Stanton Station. Work will be conducted on Unit 1 firing a subbituminous coal. Stanton Station Unit 1 is a 150-MW Foster Wheeler pc wall-fired system with low-NO_x burners. Unit 1 particulate control is accomplished with a Research-Cottrell c-ESP, and no flue gas desulfurization technology is employed.

The work plan for the Stanton Station includes three phases: baseline, parametric, and long-term testing. Specifically, impregnated and activated carbon sorbents will be injected into the flue gas at the inlet of the ESP. Plans for this project were briefly addressed in a symposium presentation entitled "Developing Mercury Control Options for Utilities Firing Western Fuels," a symposium paper entitled "Full-Scale ACI for Mercury Control in Flue Gas Derived from North Dakota Lignite," and on a NETL Web site, respectively (5, 18, 21).

Antelope Valley Station – Basin Electric Power Cooperative

The EERC, in conjunction with Basin Electric Power Cooperative and NETL, will be conducting a sorbent injection with enhancement additives project in 2005 at Basin Electric Power Cooperative's Antelope Valley Station. Work will be conducted on Unit 1 firing a North Dakota lignite. Antelope Valley Station Unit 1 is a 440-MW Combustion Engineering pc tangentially fired system with low-NO_x burners. SO₂ and particulate emission control is accomplished with SDA modules, supplied by Niro Joy Western, followed by low-air-to-cloth-ratio reverse-air FFs, supplied by Joy Western.

The work plan for the Antelope Valley Station includes three phases: baseline, parametric, and long-term testing. Specifically, activated carbon sorbents will be injected into the flue gas stream at the inlet of a SDA module. Plans for this project were briefly addressed in a symposium presentation entitled "Developing Mercury Control Options for Utilities Firing Western Fuels" and on a NETL Web site, respectively (5, 21).

Milton R. Young Station – Minnkota Power Cooperative

The EERC, in conjunction with Minnkota Power Cooperative and NETL, will be conducting a mercury oxidation project in 2005 at Minnkota Power Cooperative's Milton R. Young Station. Work will be conducted on Unit 2 firing North Dakota lignite. Milton R. Young Station Unit 2 is a 450-MW B&W cyclone-fired system. Unit 2 particulate control is

accomplished with a Wheelabrator-Frye c-ESP. SO₂ control is accomplished with a WFGD system.

The work plan for the Milton R. Young Station includes three phases: baseline, parametric, and long-term testing. Specifically, fuel and flue gas additives will be used in an attempt to shift mercury speciation from largely elemental to largely oxidized. Plans for this project were briefly addressed in a symposium presentation entitled “Developing Mercury Control Options for Utilities Firing Western Fuels” and on a NETL Web site, respectively (5, 21).

Monticello Station – Texas Utilities Company

The EERC, in conjunction with Texas Utilities Company and NETL, will be conducting a mercury oxidation project in 2005 at Texas Utilities Company’s Monticello Station. Work will be conducted on Unit 3 firing Texas lignite. Monticello Station Unit 3 is a 750-MW B&W pc wall-fired system. Unit 3 particulate control is accomplished with a Walther c-ESP. SO₂ control is accomplished with a WFGD system.

The work plan for the Monticello Station includes three phases: baseline, parametric, and extended testing. Specifically, fuel and flue gas additives will be used in an attempt to shift mercury speciation from largely elemental to largely oxidized to allow subsequent capture in the wet scrubber. Plans for this project were briefly addressed in a symposium presentation entitled “Developing Mercury Control Options for Utilities Firing Western Fuels” and on a NETL Web site, respectively (5, 21).

Big Brown Station – Texas Utilities Company

The EERC, in conjunction with Texas Utilities Company, NETL, EPRI, ADA-ES, Inc., B&W, and several Texas state agencies and a consortium of Texas and North Dakota utilities, will be conducting a 24-month project entitled “Field Testing of ACI Options for Mercury Control at TXU’s Big Brown Station” beginning in 2005. Texas Utilities Company’s Big Brown Station is located near Fairfield, Texas. Work will be conducted on one of two units firing a Texas Basin lignite or a lignite–subbituminous coal blend. Big Brown Station Units 1 and 2 are 600-MW Combustion Engineering pc tangentially fired systems. Particulate control is accomplished with Research-Cottrell c-ESPs.

The test plan for work at the Big Brown Station includes three phases: baseline, parametric, and long-term testing. Specifically, activated carbon sorbents will be injected into the flue gas stream at the inlet of a c-ESP. Plans for this project were briefly addressed in a symposium presentation entitled “Developing Mercury Control Options for Utilities Firing Western Fuels” and on a NETL Web site, respectively (5, 21).

Monroe Station – Detroit Edison

ADA-ES, Inc., in conjunction with Detroit Edison, NETL, and other organizations, will be conducting a sorbent injection project at Detroit Edison’s Monroe Station during the second

quarter of 2005. Work will be conducted on Unit 4 firing a PRB–eastern bituminous coal compliance fuel blend for SO₂ emissions. Monroe Station Unit 4 is a nominal 785-MW B&W boiler with an SCR system for NO_x control. Particulate control is accomplished with a Research-Cottrell c-ESP having an SCA of 258 ft²/1000 acfm. The demonstration test will be conducted on a flue gas volume representing a nominal capacity of 196 MW.

The test plan being developed for work at the Monroe Station includes three phases: baseline, parametric, and long-term testing. Specifically, carbon-based sorbents (not yet selected) will be injected into the flue gas stream at the inlet of the ESP. Plans for this project were briefly addressed in a quarterly technical report entitled “Evaluation of Sorbent Injection for Mercury Control” and on a NETL Web site, respectively (17, 21).

Conesville Station – American Electric Power

ADA-ES, Inc., in conjunction with American Electric Power (AEP), NETL, and other organizations, will be conducting a sorbent injection project at AEP’s Conesville Station during the third quarter of 2005. Work will be conducted on Unit 5 or 6 firing an eastern bituminous–PRB coal blend. Conesville Station Units 5 and 6 are nominal 400-MW Combustion Engineering boilers. Particulate control is accomplished with a Research-Cottrell c-ESP having an SCA of 301 ft²/1000 acfm. The ESP is followed by a WFGD system for control of SO₂ emissions.

The work plan being developed for the Conesville Station includes three phases: baseline, parametric, and long-term testing. Specifically, carbon-based sorbents (not yet selected) will be injected into the flue gas stream at the inlet of the ESP. Plans for this project were briefly addressed in a quarterly technical report entitled “Evaluation of Sorbent Injection for Mercury Control” and on a NETL Web site, respectively (17, 21).

URS

URS, in conjunction with Texas Utilities Company, Georgia Power, American Electric Power, NETL, EPRI, Southern Company, and Degussa Corporation, will be conducting a 12-month project entitled “Field Testing of Additive to Remove Mercury from FGD Systems and Prevent Re-emissions” beginning in 2005. The project will evaluate the use of an additive in wet lime and limestone FGD systems to prevent mercury reemissions in coal-fired power plants. The additive is intended to prevent oxidized mercury captured in an FGD system from being reduced and subsequently reemitted into the flue gas stream as elemental mercury. In addition, the additive assists in the removal of mercury from by-products and its separate disposal. Field sites selected for this demonstration project include 1) Texas Utilities Company’s Monticello Station at Mt. Pleasant, Texas; 2) Georgia Power’s Plant Yates at Newnan, Georgia; and 3) AEP Conesville Station at Conesville, Ohio. Some information concerning the project is summarized on a DOE NETL Web site (21).

ADA-Environmental Solutions, Inc.

ADA-ES, Inc., in conjunction with EPRI, Dynegy, NETL, and Olgethorpe Power, will be conducting a project entitled “Testing TOXECON II and Unique Sorbent Injection into h-ESPs” beginning in 2005. TOXECON II technology involves ACI directly into the downstream collecting fields of an ESP. With the majority of the fly ash collected in the upstream fields, only a small portion of the fly ash is contaminated with carbon. The second technology to be tested involves the injection of novel sorbents for mercury removal on units with h-ESPs. Field sites identified included Mid America Energy’s Louisa Station and Council Bluffs Station, AEP’s Gavin Station, and Entergy’s Independence Station. Some information concerning the project is summarized on a NETL Web site (21).

ALSTOM Power, Inc.

ALSTOM Power, Inc., in conjunction with PacificCorp, Basin Electric Power Cooperative, Reliant Energy, NETL, the EERC, the North Dakota Industrial Commission, and Minnkota Power Cooperative, will be conducting a 30-month project entitled “Testing Proprietary Activated-Carbon-Based Sorbents and Additives” beginning in 2005. The activated carbon-based sorbent, prepared with chemical additives, is intended to promote oxidation and capture of mercury. Field sites selected for this demonstration project include the following:

- 1) PacificCorp’s Dave Johnston Station at Glenrock, Wyoming, firing a subbituminous coal;
- 2) Basin Electric’s LOS at Stanton, North Dakota, firing a North Dakota lignite; and
- 3) Reliant Energy’s Portland Station at Portland, Pennsylvania, firing a bituminous coal.

Some information concerning the project is summarized on a NETL Web site (21).

GE Energy

GE Energy, in conjunction with Tennessee Valley Authority (TVA) and NETL, will be conducting an 18-month project entitled “Testing Technology for Concurrent Control of Hg and NO_x Emissions” beginning in 2005. GE Energy has developed a cost-effective technology combining mercury and NO_x control with a mercury removal objective of at least 90%. The field site selected for this demonstration is TVA’s John Sevier Station in Rogersville, Tennessee, firing a bituminous coal. Some information concerning the project is summarized on a NETL Web site (21).

Sorbent Technologies Corporation

Sorbent Technologies Corporation, in conjunction with Midwest Generation, Progress Energy, Headwaters/ISG Resources, NETL, Fuel Tech, Inc., Western Kentucky University, and Acticarb Tailored Products LLC, will be conducting a 24-month project entitled “Testing B-PAC™ Technology for Mercury Control,” beginning in 2005. This project will demonstrate how the injection of brominated powdered activated carbon (B-PAC™) and a concrete-safe version of the carbon can cost-effectively control mercury emissions from coal-fired power plants

operating both c- and h-ESPs. Specific demonstration sites were identified as Midwest Generation's Will County and Crawford Stations and Progress Energy's Lee Station. Some information concerning the project is summarized on a NETL Web site (21).

Amended Silicates

ADA Technologies has developed a new class of clay-based adsorbents for mercury and other metals, called Amended Silicates™ (22, 23). These materials use inexpensive silicate substrates, impregnated with chemicals that possess a strong affinity for the target metal. The sorbent is prepared by ion exchange between the silicate substrate and a solution containing one or more of a group of polyvalent metals including tin (both Sn[II] and Sn[IV]), iron (both Fe[II] and Fe[III]), titanium, manganese, zirconium, and molybdenum, dissolved as salts, to produce an exchanged substrate. Controlled addition of sulfide ions to the exchanged silicate substrate produces the sorbent.

Bench-scale testing with the best formulations confirmed that the Amended Silicates exhibit mercury capacities greater than that of activated carbon. The primary advantage of these materials is their silicate structure; Amended Silicates do not appear to adversely impact the use of fly ash as a pozzolan material. Amended Silicates also are less sensitive to moisture, temperature, and acid gas concentration than carbon. These are detrimental factors in the use of activated carbon for mercury control, as excess carbon in fly ash could force a utility to pay for ash disposal rather than collecting revenue from its sale. Handling and injection of Amended Silicates are similar to that of activated carbon. The silicates are easily collected in an ESP or FF. Following the extensive laboratory tests, pilot-scale tests were done using a nominal 500–1000-acfm slipstream at Xcel Energy's Comanche Station, which burns a PRB coal. Both the pilot- and full-scale plant were equipped with a reverse-gas FF. The temperature of the pilot unit ranged from 200° to 325°F (94° to 163°C). Two Amended Silicates sorbents were tested at rates that were varied from 1.6 to 9 lb/Macf. For comparison, ACI also was tested at an add rate of 4.2 lb/Macf. The results are shown in Figure 2. As can be seen, the Amended Silicates provided performance similar to activated carbon with the advantage of lower unit cost and little, if any, impact on the fly ash. It is expected that the cost of the Amended Silicates will be \$0.30–\$0.40/lb compared to \$0.50 for DARCO FGD. The same equipment used for ACI can be used to inject Amended Silicates; therefore, capital costs will be the same.

For those power plants that sell their fly ash, the use of Amended Silicates may be an option. However, long-term testing is necessary to conclusively prove the technology. Full-scale demonstration tests are being planned at Xcel Energy's Arapahoe Station and at Cinergy's 175-MW Miami Fort Station. The Arapahoe Station is similar to the Comanche Station, as it burns a PRB coal and has an FF for particulate control. Testing is expected to begin early in 2005. Testing at Cinergy's 175-MW Miami Fort Station will be done as part of NETL's full-

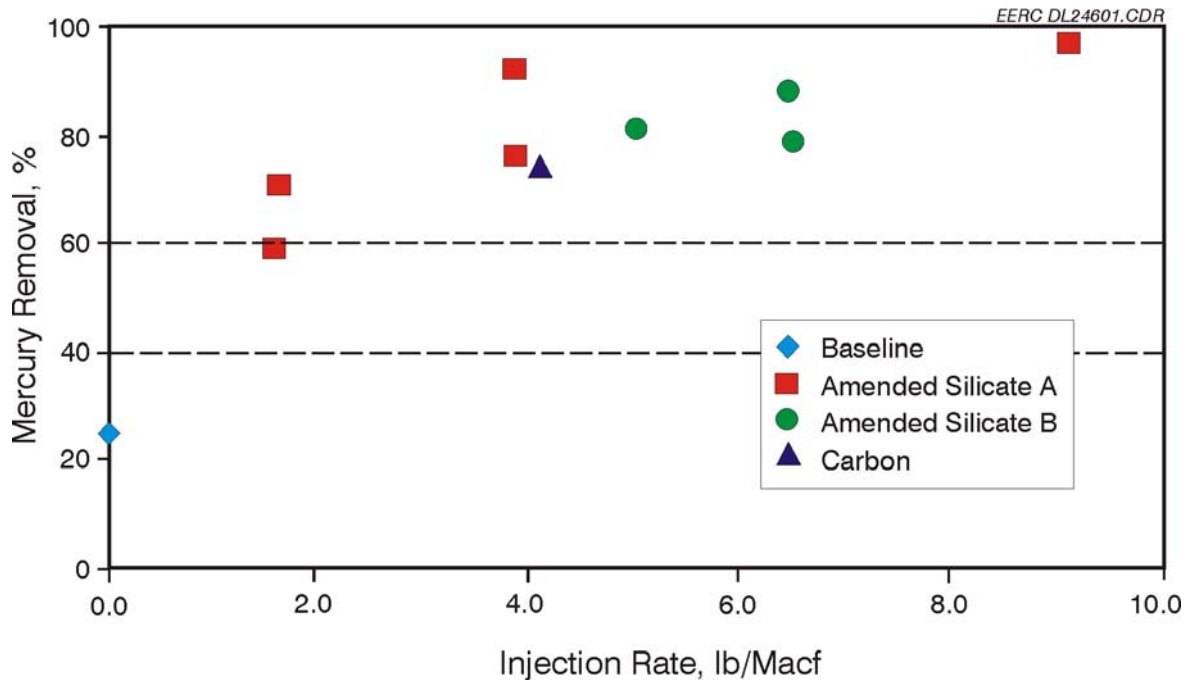


Figure 2. Mercury removal rates from pilot slipstream tests.

scale demonstration program. The unit upon which the test will be conducted at the Miami Fort Station has an ESP and burns an Ohio bituminous coal. Testing at this facility is also expected to begin in the spring of 2005. In a commercial partnership with CH2M Hill, the sorbent-manufacturing process is being scaled up to manufacture quantities of Amended Silicate sorbents to meet projected needs of the demonstration tests with the anticipation of increasing production for a permanent, full-scale operation.

UPDATES ON PREVIOUS QUARTERLIES

Quarter 1 was a general overview of the topic “Sorbent Control Technologies for Mercury Control.” The specific technologies are described in the current quarterly as they relate to specific field demonstrations.

Quarter 2 was on the topic of “Mercury Measurement”; there have been a number of developments since April 2004 (see Appendix A).

Quarter 3 was on the topic of “Advanced and Developmental Mercury Control Technologies”; the updates are in Appendix B.

Quarter 4 has no updated information on the rerelease of mercury from coal combustion by-products.

Quarter 5 has no updated information on mercury fundamentals.

UPCOMING EVENTS

International Conference on Clean Coal Technologies for Our Future

May 10–12 2005, Sardinia, Italy

Contact Rodney Anderson (304) 285-4709

<http://fossil.energy.gov/news/events/>

IGCC Symposium: Examine Technology Risk, Costs, Financing, Environmental Performance,
and IGCC's Future in the Power Industry

June 2–3, 2005, Pittsburgh, Pennsylvania

<http://www.events.platts.com>

A&WMA 98th Annual Conference and Exhibition

June 21–24, 2005, Minneapolis, Minnesota

<http://www.awma.org>

230th ACS National Meeting

August 28–September 1, 2005, Washington, D.C.

<http://oasys.acs.org/acs/230nm/topics.html>

Air Quality V: Mercury, Trace Elements, and Particulate Matter Conference

September 18–21, 2005, Washington, D.C.

<http://www.undeerc.org>

Eighth International Conference on Mercury as a Global Pollutant

August 6–11, 2006, Madison, Wisconsin

<http://www.mercury2006.org/Default.aspx?tabid+1393>

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APPENDIX A

**UPDATE OF QUARTER 2
MERCURY MEASUREMENT**

UPDATE OF QUARTER 2 MERCURY MEASUREMENT

Since April 2004, when the Mercury Information Clearinghouse second quarterly report was released, there have been a number of developments in mercury measurement, including the following:

- On March 15, 2005, the Clean Air Mercury Rule was announced by the U.S. Environmental Protection Agency (EPA), regulating mercury from U.S. coal-fired power plants for the first time.
- New mercury measurement techniques have been developed.
- Additional experience was gained with next-generation continuous mercury monitors (CMMs).

Clean Air Mercury Rule (<http://www.epa.gov/mercuryrule>)

The new regulations for mercury emissions from U.S. coal-fired boilers were announced under Section 111 of the Clean Air Act Amendments and, as such, will be cap-and-trade rules. Some form of CMM will be required. EPA has announced that two measurement methods will be accepted: the sorbent trap method previously referred to as Proposed EPA Method 324 and/or QuickCEMs™, now officially named 40 CFR, Part 75, Appendix K, and CMMs. It is expected that most U.S. utilities will use the sorbent trap method; however, this could change as more robust CMMs become available. For both of these methods, EPA has established performance specifications (PS 12A), which relate to the setup, certification, and quality assurance/quality control (QA/QC) for each method. A summary of these specifications is provided; for details, go to www.epa.gov/mercuryrule.

40 CFR, Part 75, Appendix K Specifications

Each sorbent trap is to be configured with three distinct but identical sections connected in series such that each can be analyzed separately. The first section is to be the primary trap for the gas-phase mercury. The second section is to be a backup to prevent mercury breakthrough. The third section is designated for QA/QC and is, therefore, spiked with a known amount of gaseous elemental mercury (Hg^0) prior to the trap. Also, paired traps must be used, with the mercury results averaged. The specific sorbent and analysis types are not specified; however, the method used must pass the QA/QC requirements as shown in Table A-1. The sampling flow rate must maintain proportional sampling (the ratio of stack flow rate to sample flow rate is constant). Also, a continuous monitoring system must be used to determine the moisture in the stack gas.

Table A-1. Sorbent Trapping QA/QC Specifications

QA/QC Specifications	Acceptance Criteria	Frequency	Consequences if Not Met
Pretest Leak Check	≤4% of target sampling rate	Prior to sampling	Sampling cannot begin
Posttest Leak Check	≤4% of target sampling rate	After sampling	Sampling invalidated
Proportional Sampling Rate	Maintain within 25% of initial from first hour of collection	Every hour	Case-by-case evaluation
Sorbent Trap Sec. 2 Breakthrough	<5% of Sec.1 Hg mass	Every sample	Sample invalidated
Paired Sample Trap Agreement	<10% relative deviation	Every sample	Sample invalidated
Spike Recovery Study	±15% for each of three Hg conc. levels	Prior to analyzing field samples and prior to using a new sorbent	Field samples cannot be analyzed until criteria are met
Multipoint Analyzer Calibration	10% of true value and $r^2 \geq 0.99$	Each day prior to analysis of field samples	Recalibrate until criteria are met
Analysis of Standard Sample	10% of true value	Each day prior to analysis of field samples	Repeat until criteria are met
Spike Recovery (Sec. 3 of trap)	±25% of spiked concentration	Every sample	Paired sample trap invalidated
RATA (paired OH trains)	$RA \leq 20.0\%$ or mean diff. of $\leq 1 \mu\text{g/dscm}$	For initial certification, then annually	Cannot begin sampling until RATA is passed
Dry gas meter calibration (initially at 3 setting and 1 setting thereafter)	Calibration factor (Y) within 5% of average value from initial 3 point calibration	Prior to initial use, quarterly thereafter	Recalibrate the meter at three orifice settings to determine a new Y
Temperature Sensor Calibration	Absolute temperature measured by sensor within ±1.5% of ref. sensor	Prior to initial use, quarterly thereafter	Recalibrate; sensor may not be used until specifications are met
Barometer Calibration	Absolute pressure measured by instrument within ±10 mm Hg reading with a Hg barometer	Prior to initial use, quarterly thereafter	Recalibrate; instrument may not be used until specifications are met

CMMs

The requirements for the use of CMMs are essentially the same as previously stipulated in PS 12A when the proposed mercury rule was released for public comment in January 2004. The primary difference is that for calibration and system checks, either elemental or oxidized mercury (Hg^{2+}) calibration gases can be used. A summary of the requirements is presented below.

For initial certification, EPA requires the following tests for CMMs:

- A 7-day calibration error test using Hg^0 calibration gas standards or a National Institute of Standards and Technology (NIST) traceable source of Hg^{2+} may be used. The monitor must meet a performance specification of 5.0% of span on each day of the test (for span values of $10 \mu\text{g/scm}$) or an alternate specification of $1.0 \mu\text{g/scm}$ absolute difference between reference gas and the CMMs.

- A three-point linearity check, using Hg^0 calibration gas standards. The monitor must meet a performance specification of 10.0% of the reference concentration at each gas level or an alternate specification of 1.0 $\mu\text{g}/\text{scm}$ absolute difference between reference gas and the CMMs.
- A cycle time test. The maximum allowable cycle time would be 15 minutes.
- A RATA using paired Ontario Hydro (OH) method trains. The results must agree within 10% of the relative standard deviation, and the results should be averaged.
- A bias test, using data from the RATA, to ensure that the CMMs is not biased low with respect to the reference method.
- A three-point system integrity check, using mercuric chloride (HgCl_2) standards. The monitor would be required to meet a performance specification of 5.0 % of span at each gas level.

For ongoing QA/QC, the following QA/QC tests are required:

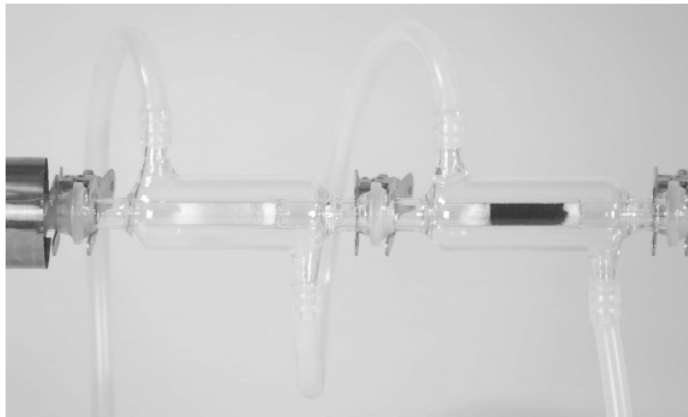
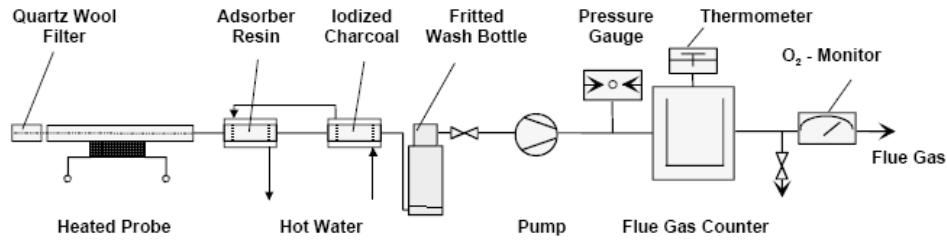
- Daily two-point calibration error checks, using Hg^0 gas standards or a NIST traceable source of Hg^{2+} . The monitor would be required to meet a performance specification of 7.5% of span or an alternate specification of 1.5 $\mu\text{g}/\text{scm}$ absolute difference between reference gas and CMMs.
- If daily calibrations are done using Hg gas standards, a weekly system integrity check at a single point must also be completed using a NIST traceable source of Hg^{2+} . The weekly test is not required if daily calibrations are performed with a NIST traceable source of oxidized Hg.
- Quarterly three-point linearity checks, using Hg^0 gas standards. The performance specifications would be the same as for initial certification. Quarterly three-level system integrity checks (using a NIST traceable source of Hg^{2+} may be performed in lieu of the quarterly linearity checks with Hg^0 .
- Annual RATA and bias tests. The performance specifications would be the same as for initial certification.

New Mercury Measurement Methods

Two new mercury measurement methods, the E.ON Engineering sorbent trap method and the Cooper Environmental Services LLC filter tape XACT method, were presented at the U.S. Department of Energy National Energy Technology Laboratory- and EPRI-sponsored Mercury Measurements Workshop, July 2004. The presentation about the two methods can be obtained at the following Web site: www.netl.doe.gov/publications/proceedings/04/HgWorkshop.

The E.ON method is similar to other sorbent trap methods such as the flue gas mercury speciation (FAMS) method that was described in the Quarterly 2 report. The only real difference is that in place of the solid KCl trap, an adsorber resin is used to remove the Hg^{2+} . The adsorber resin is a Dowex 1×8 resin that chemisorbs Hg^{2+} . A schematic of the train is shown in Figure A-1.

Sampling Train



↑
Adsorber Resin

↑
Iodized Charcoal

Figure A-1. Diagram of E.ON Engineering mercury speciation sampling train.

The detection limit is stated by E.ON as $0.05 \mu g/m^3$, assuming a $1-m^3$ sampling volume. Table A-2 presents the blank test results for this method.

Because this method was developed in Germany, there has only been limited testing in the United States. This method must be compared to the Ontario Hydro (OH) method and validated. At this time, only E.ON is using the method, so its availability is limited. In addition, little is known about the QA/QC procedures that are outlined in the Clean Air Mercury Rule for 40 CFR, Part 75, Appendix K as they relate to the E.ON method.

Table A-2. Specification for the E.ON Mercury Speciation Method

Trap	Average Value, µg/m³	Std. Dev., µg/m³	Detection Limit*, µg/m³
Digestion Blank	0.004	0.002	0.010
Dowex Resin Blank	0.007	0.003	0.015
Iodized Charcoal Blank	0.012	0.006	0.030

*Detection limit defined as 5 × std. dev.

The filter tape XACT method is a semicontinuous multimetals analyzer that uses an intermittently moving tape containing an adsorbent that is sequentially exposed to flue gas. Once a deposit forms on the tape, it is analyzed for mercury and other metals using x-ray fluorescence x-ray fluorescence (XRF). The result is a total mercury concentration (particulate-bound and gaseous forms). The only conditioning required is the addition of dilution gas to cool the sample. XRF is a nondestructive technique so the sample filters may be archived for future analysis. This system can be used to measure 25 elements in stack gas emissions. The sample time can be varied from about 15 minutes per analysis to over 1 hour, depending on how long the tape is exposed to the flue gas. The detection limit is defined by the period of time that each section of the tape is exposed to the flue gas. For very low mercury concentrations, longer periods of time are needed compared to locations with higher mercury concentrations. For a typical coal boiler (10 µg/Nm³), 1 hr would provide a detection limit of 0.1 µg/Nm³.

In many ways, the QA/QC for the method is similar to those for other continuous/semicontinuous mercury monitors and may well fit under the PS-12A specifications listed in the new mercury rule. However, the 15-minute cycle time may be a problem. Currently, Cooper Environmental is doing system calibrations using NIST thin-film standards and confirming the calibration factors with a quantitative aerosol generator (QAG). These QAG tests have demonstrated that the XACT method has a precision of about 2% and accuracies better than 5% for the five metals, Cr, As, Cd, Hg, and Pb.

An updated CMM vendor list is shown in Table A-3. Several of the monitors listed previously are not considered commercially available for measuring mercury in combustion flue gases. In addition, several companies, including Ohio Lumex and PS Analytical, are developing new pretreatment/conversion systems that should be commercially available by the fall of 2005.

Comparisons of Wet-Chemistry and Dry Pretreatment/Conversion Systems

A conditioning/conversion system is arguably the most important part of a mercury measurement system. This is the point where the unknown sample gas is conditioned by removing interfering flue gas components or reducing their impact by dilution. Flue gas composition varies widely based on coal type and plant configuration, presenting numerous challenges for the measurement systems. Wet-chemistry systems have been used extensively, and many of their limitations have been identified. These systems remove interfering constituents by bubbling the sample gas through reactive solutions. The main concerns with the wet systems include the following:

- The amount of chemicals used and the volume of waste generated

- Capture of an unknown amount of CO₂, which affects the sample volume
- Mercury “hang-up” in the system, which changes with changing equilibrium
- Condensation of flue gas constituents such as SO₃ and selenium
- Potential for unidentified chemical reactions

A model to predict CO₂ capture by the NaOH solution is under development. Mercury hang-up changes in flue gas and the mercury concentration spikes, indicating a release of mercury from the sampling system. The spikes are attributed to changes in the equilibrium of the mercury in the sample gas with the small amount of mercury captured in the sampling system. Changes in the acid gas concentrations can cause mercury to desorb from surfaces where it has accumulated over time. When condensation of flue gas constituents is observed, the system temperatures are increased to eliminate it.

As the use of dry pretreatment/conversion systems becomes more common, new issues are emerging. All dry systems use thermal treatment to convert all the mercury in the flue gas to elemental mercury. Some monitors (Ohio Lumex and the Thermo Electron system under development) use direct thermal treatment. The entire system remains hot to prevent recombination. More commonly, a catalyst is used to allow thermal decomposition of mercury at lower temperatures. Examples of such systems include the Horiba/NIC DM-6B and Durag HM-1400 TR. For a monitor that uses the more sensitive cold-vapor atomic fluorescence method (i.e., Tekran 3300), dilution thermal systems can be used.

In addition to converting the mercury, the unit must also deliver mercury to the analyzer without any interfering gases. Most of these systems are not completely dry; they often use small amounts of chemicals or water to remove potential contaminants from the sample gas stream. In addition to being susceptible to the same problems as wet-chemistry conditioning/conversion systems, they have had issues with catalyst life. Catalysts have either failed or exhibited a short life when challenged with sample streams containing high concentrations of acid gases. For example, in tests using the Horiba/NIC system at a plant with high levels (>50 ppm) of SO₃, the catalyst lasted less than 24 hours. In some plants, selenium precipitates out in the conversion system, reducing measured mercury. This can usually be rectified by ensuring there are no cold spots in the system. In some cases, it is necessary to use a small amount of basic solution to remove selenium prior to the catalyst.

The dry systems that utilize dilution to eliminate the effects of interfering gases have not been used for any period of time in high-acid gas environments; therefore, it is unknown how they will perform under these conditions. However, at a facility firing a Powder River Basin coal (low sulfur and chlorides), the dry Tekran system has been in continuous operation for more than 1 year with no reported problems. The Energy & Environmental Research Center has been measuring the mercury concentration at the inlet and outlet of a slipstream at a lignite facility (again, relatively low in sulfur and chlorides) since September 2004 using two Tekran dry systems. The only issue that has been identified is fine particulate matter penetrating the inertial separation probe. Potentially, particulate matter could build up in the critical orifice in the conversion unit used to control the sample gas flow rate. Another challenge is that if something goes wrong with the analyzer, it is impossible to verify the dilution rate in the field. Because of the system design, the instrument must be returned to Tekran for a dilution rate check.

Table A-3. Commercially Available CMMS

Vendor	Product	Analysis Method	Pretreatment/ Conversion	Speciating ¹	Web Site
Cooper Environmental Services ²	XACT	XRF	Dilution for cooling	Hg ^{total} (g, p)	www.cooperenvironmental.com
Durag	HM-1400 TR	CVAA	Thermal catalytic	No	www.durag.net
EcoChem Analytics ³	Hg-MK II	CVAA	Thermal catalytic	Yes	www.ecochem.biz
Envimetrics	Argus-Hg 1000	Atomic emission	Thermal catalytic	No	www.envimetrics.com
Horiba/NIC	DM-6B	CVAA	Thermal catalytic	Yes	www.environ.hii.horiba.com
OhioLumex	RA-915+	CVAA	Direct Thermal	No	www.ohiolumex.com
Opsis AB	HG200	CVAA	Dilution system	Yes	www.opsis.se
PS Analytical	Sir Galahad	CVAF	Wet/dry chemistry (2005)	Yes	www.psanalytical.com
Semtech Metallurgy AB	Hg 2010	CVAA	Wet chemistry	No	www.semtech.se
Sick UPA GmbH	MERCEM	CVAA	Wet chemistry	No	www.cemsi.on.ca
ST ² Technologies	SM-3	CVAA	Thermal catalytic	Yes	www.st2-service.com
Tekran, Inc.	3300	CVAF	Dilution system	Yes	www.tekran.com

¹ The analyzers that speciate mercury measure total gas-phase mercury and elemental mercury and determine oxidized mercury by difference.

² The Cooper Environmental XACT analyzer is a multimetal unit that measures both particulate-bound mercury and total gas-phase mercury.

³ The EcoChem Hg-MK II can be purchased as a speciating dual analyzer or as single, total gas-phase mercury analyzer.

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APPENDIX B

**UPDATE OF QUARTER 3
ADVANCED AND DEVELOPMENTAL MERCURY
CONTROL TECHNOLOGIES**

UPDATE OF QUARTER 3 ADVANCED AND DEVELOPMENTAL MERCURY CONTROL TECHNOLOGIES

MerCAP™

Results from initial testing at the Stanton Station were presented at the most recent Mega Symposium, held in Washington, D.C., August 30–September 2, 2004 (1). While plans are to evaluate the technology on a full baghouse compartment (6-MW scale), the only results reported were from a much smaller 140-acfm test probe. The reported results with several configurations showed rapid deterioration of mercury removal from a starting value of 80% to less than 20% within 15–20 hours of operation. This is in stark contrast to the previously reported 2000 hr of operation with only moderate deterioration. These latest results indicate that a better understanding is needed of how the presence of specific flue gas components can lead to rapid deactivation of the substrate surfaces.

EnviroScrub Pahlman Process

Recent mercury control results from slipstream testing at the Minnesota Power Boswell plant were presented at the last Mega symposium (2) and in an Energy & Environmental Research Center report to the U.S. Department of Energy National Energy Technology Laboratory (3), which cofunded the work. The best mercury removal seen was 99% (elemental) and 94% (total) for a batch test in which testing was started immediately following sorbent loading. However, when sampling was started 2 hr after different levels of sorbent loading, total mercury removal was 76% in one case and 91% for the second case. At longer exposure times, the level of mercury control further declined even though the SO₂ removal remained over 90%. This suggests that the process may need to be optimized for the highest level of mercury control independent of the level of SO₂ control. These batch tests may not be indicative of the process in continuous mode. Mercury control with the continuous process has not been demonstrated.

Mercury Control with the *Advanced Hybrid*™ Filter

The perforated-plate geometry of the *Advanced Hybrid*™ filter is intended to provide sufficient gas–solid contact to achieve over 90% mercury removal at low carbon addition rates, even though most of the carbon is collected on the perforated plates rather than on the bags. To prove this, recent tests measured the amount of mercury collected by the perforated plates in the *Advanced Hybrid*™ filter apart from any mercury control on the filter bags (4). Results showed that at a relatively small carbon injection rate with an enhanced sorbent, 90% mercury control was seen across the plates. This is important because it shows that efficient mercury control can be achieved by collecting the carbon on the perforated plates alone. To achieve good mercury control, the carbon need not be collected on the filter bags, which can lead to pressure drop problems. These results are consistent with pilot-scale and field data that have always shown that carbon injected upstream of the *Advanced Hybrid*™ filter for mercury control has little or no effect on pressure drop.

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