Mercury Control with Activated Carbon: Results from Plants with High SO_3

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ABSTRACT

The presence of SO_3 in the flue gas, whether as the result of high-sulfur coal, the presence of an upstream SCR, or an SO_3 injection system for flue gas conditioning, can impair the effectiveness of activated carbon for mercury removal. Full-scale evaluations of sorbent injection for mercury removal have been conducted over the past two years to characterize and assess alternatives to enhance mercury removal. These tests have been funded by DOE/NETL, EPRI, and electric generating plant industry partners.

This paper will present results from testing including the testing of traditional and alternative sorbents on mercury emissions, the influence of SO_3 concentration and flue gas temperature on mercury removal efficiency, and the effectiveness and economics of dual injection for SO_3 and mercury control.

INTRODUCTION

As of late 2007, mercury control systems had been ordered for 80 units in response to state regulations and new source requirements under the Clean Air Mercury Rule (CAMR). These regulations require the power industry to respond quickly to meet the implementation schedules. Although the U.S. Court of Appeals for the District of Columbia vacated CAMR on February 8, 2008, removing any federal regulations that require monitoring or control of mercury from electric generating units, it is expected that new, possibly stricter regulations will be implemented in the future. Furthermore, on July 11, 2008, the D.C. Circuit vacated EPA's Clean Air Interstate Rule. CAIR was established to permanently cap emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) in the eastern United States. In preparation of CAIR implementation, many plants were planning scrubber and selective catalytic reduction (SCR) installations that were expected to provide some co-benefit mercury removal.

Several challenges to the successful implementation of activated carbon injection (ACI) for mercury control were identified during early testing under the DOE/NETL Phase I and II mercury control programs.[1,2] Theorized in the laboratory and demonstrated at several sites during early tests, one of the more difficult applications for mercury control with ACI is sites with high levels of SO_3 in the flue gas generated from the coal, flue gas conditioning, or an SCR.[3,4] Laboratory studies conducted over the past 15 years by URS Group, UNDEERC, and others indicate that HCl and SO_x in the flue gas can significantly affect the mercury adsorption capacity of fly ash and activated carbon.[5,6] These studies suggest that SO_2 and SO_3 reduce the equilibrium mercury capacity of activated carbon and fly ash because activated carbon tends to catalyze SO_2 to H_2SO_4. In turn, these sulfur compounds occupy surface sites on the carbon that are normally available to adsorb and oxidize mercury. Hence, the mercury adsorption capacity is dependant on the SO_2 and SO_3 concentration, which is orders of magnitude greater than the mercury concentration. The vacatur of CAIR, in combination with new and pending mercury control regulations, creates uncertainty in the regulatory landscape, leaving open the possibility of even more stringent mercury control requirements. Therefore, it is important to continue evaluating options to remove mercury from plants with higher levels of SO_2 and SO_3.

High-SO_3 flue gas can be a result of firing high-sulfur bituminous coals, oxidation of SO_2 to form SO_3 by an SCR, and/or SO_3 injection for flue gas conditioning. ADA-ES has worked with the DOE/NETL, EPRI, and several electric generating plant partners to evaluate options to improve the effectiveness of sorbent-based mercury control for sites with higher levels of SO_3 in the flue gas. The first effort covered by this paper to understand and quantify the effect of SO_3 was the DOE/NETL- and EPRI-sponsored project at American Electric Power's (AEP) Conesville Unit 6. The SO_3 in the flue gas (30 ppm) at Unit 6 was generated through the combustion of a high-, and variable-, sulfur coal. The next two projects to explore the effect of higher levels of SO_3 were Public Service of New Hampshire (PSNH) Merrimack Station Unit 2 and Ameren's Labadie Station Unit 2. Merrimack Station generated a higher-level SO_3 flue gas through a combination of combusting a medium-level sulfur coal blend (1.2% sulfur target blend) and a hot-side SCR, which oxidized SO_2 to increase the SO_3 levels (10–20 ppm). Labadie Station is a PRB plant with an SO_3 injection system for flue gas conditioning (0–10 ppm). These three configurations—combustion of high-sulfur coal, SCR-oxidized SO_2, and SO_3 injection for flue gas conditioning—cover the spectrum of typical plant configurations that will present SO_3 challenges for the successful application of powdered activate carbon (PAC) injection for mercury control.

EXPERIMENTAL METHODS

Activated carbon injection is a relatively low-capital-cost mercury control option for power plants; however, the economic effectiveness of utilizing the ACI system for power plants with high levels of SO_3 in the flue gas can be greatly reduced if high injection concentrations of sorbent are required to effectively lower mercury levels to comply with regulations. Additionally, high sorbent injection rates can increase particulate emissions and reduce the ability of the plant to utilize/dispose of the fly ash activated carbon mixtures. The ACI tests at Conesville, Merrimack, and Labadie were designed to address these issues for plants with different causes of higher SO_3 levels. Improved sorbents, designed for mercury capture from high-SO_3 flue gas, were evaluated. In some cases, the flue gas was treated to remove the SO_3 (before injection of activated carbon) through the use of SO_3 sorbents/reagents. The balance-of-plant impacts were considered for all options.

Site Descriptions

Table 1 is a list of key operating parameters for the three host sites discussed in this paper.

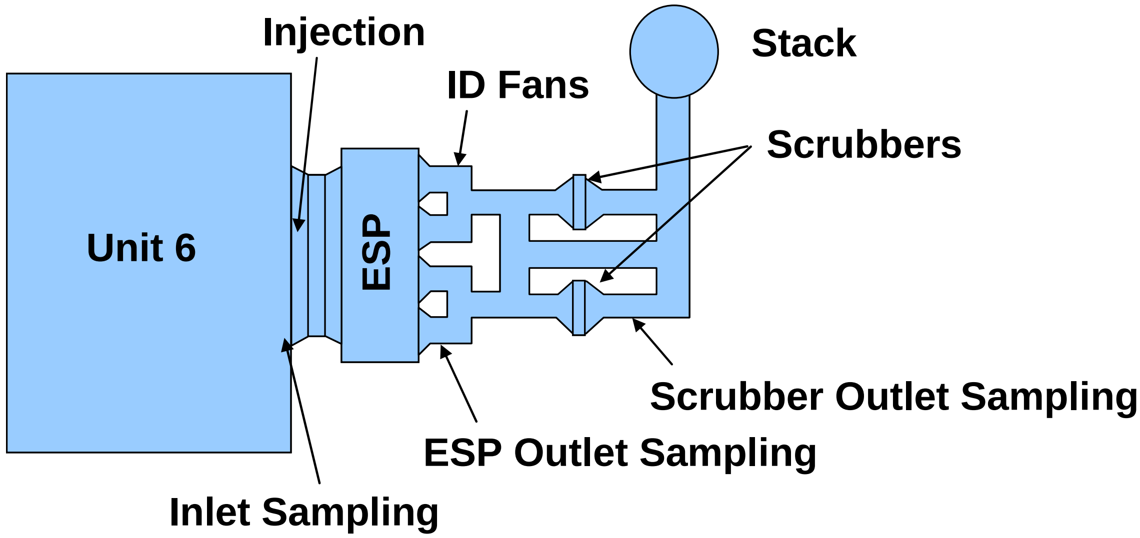
Table 1. Key operating parameters.

	Conesville	**Merrimack**	**Labadie**
Test Period	03/06–05/06	09/06–04/08	11/06–01/07
Unit	6	2	2
Size (MW)	400	335	630
Test Portion (MWe)	400	335	630
Coal	Bituminous	Test Blend (Bit/Venezuelan)	PRB
NO_x Control	None	SCR	LNB, LNCFS Level III, SOFA
Particulate Control	Research-Cottrell ESP	ESP (two in series)	ESP (three in parallel)
SCA(ft^2/kacfm)	301	330 total	279 combined
ESP Inlet Temp (ºF)	290–365	330–350	300–350
FGC	None	None	SO_3
Sulfur Control	Wet Lime FGD	Coal Blend (1.2% S)	Compliance Coal
SO_3 Flue Gas Levels (ppm)	20–30	10–20	0–11
Typical Inlet Hg (μg/dNm^3)	15–30	6–9	10–12
Typical Native Hg Removal	50%	< 10%	< 30%

Conesville Station

American Electric Power's 400-MW Conesville Station was chosen as a test host site for a DOE Phase II mercury control program (DOE Award Number DE-FC26-03NT41986) with the knowledge that this plant would present challenges for mercury control with solid sorbents. The primary objectives of testing at this plant were to determine the cost, effectiveness, and balance-of-plant impacts of sorbent injection for mercury control. Conesville Unit 6 was chosen for this evaluation because it fires high-sulfur (3 to 4%) eastern bituminous coal and is equipped with a medium-sized, cold-side electrostatic precipitator (ESP) (SCA = 301 ft^2/kacfm) for particulate control and a wet flue gas desulphurization (WFGD) system for SO_2 control. The configuration at Conesville allowed an evaluation of the effects of sorbent injection on mercury control, ESP performance (with an ESP that is representative of many units across the country), and WFGD performance. A sketch of the unit layout is presented in Figure 1.

Figure 1. Layout sketch of Conesville Unit 6.



The single ESP inlet at Conesville Unit 6 is split among four compartments. Each ESP compartment has eight electrical fields in series and eight hoppers: four front-to-back and two side-to-side. During the test program, sorbent was injected upstream of the ESP across either the entire, or across half, of the inlet duct to treat either 100% or 50% of the flue gas.

PSNH Merrimack Station

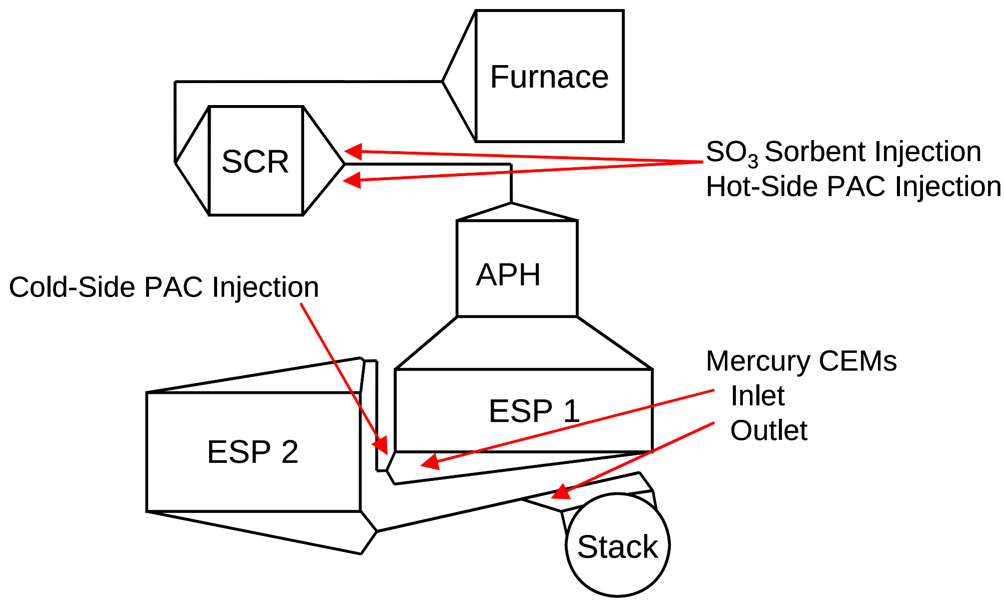
PSNH has worked with the New Hampshire (NH) Legislature and the NH Department of Environmental Services (DES) to review the technical feasibility and costs associated with different levels of mercury control at the company's coal-fired power plants. NH House Bill 1673, signed into law by the Governor of New Hampshire, requires by July 1, 2013, an 80% reduction of mercury emissions from PSNH's coal-fired power plants. The law provides incentives to achieve mercury reductions prior to July 1, 2013, and additional reductions after 2013. Because of early reduction language in the state regulation bill, PSNH is choosing to address issues now that many plants across the country will face over the next few years.

Merrimack Station Unit 2 (MK2) is a very difficult yet important application for mercury reduction technology for a number of reasons. MK2 has an SCR system that oxidizes SO_2 into SO_3. Thus, the flue gas stream, which is generated from the combustion of a medium-sulfur (1.2% sulfur target) blended coal supply, resembles that of a higher-sulfur flue gas stream in terms of the SO_3 content. In addition, typical flue gas temperatures range from 330 to 350 °F, which is in the range that detrimentally impacts activated carbon performance.

Prior to implementing the permanent compliance strategy of installing a wet scrubber in 2013, it is important to gather data and assess whether PSNH can economically achieve the early mercury reductions allowed under NH House Bill 1673 while meeting guiding principles that include 1) integrating environmental quality, public health and safety, and economic vitality; 2) facilitating scientifically and technically sound, cost-effective, and environmentally appropriate solutions; and 3) protecting fuel diversity, and PSNH's ability to generate low-cost, reliable energy necessary to meet customer demand.

During DOE Phase III testing (DOE Award Number DE-FC26-06NT42780), MK2 fired a test blend of eastern bituminous and Venezuelan coals (1.2% sulfur target). The unit is rated at 335 MW. Unit 2 is equipped with one SCR and air preheater (APH) with two ESPs in series downstream of the APH. The APH is a tubular design. Table 1 summarizes the important operating parameters of the unit. Figure 2 shows the MK2 configuration along with the injection and sampling locations. Testing was conducted across the full unit.

Figure 2. Merrimack Station Unit 2 configuration and sampling locations.



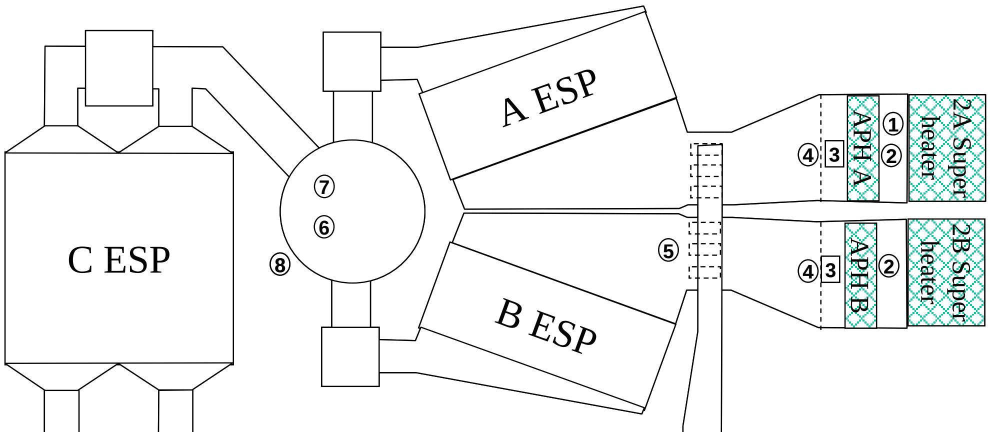
Labadie Power Plant

Across the U.S., approximately 25 GW of power is produced from units firing PRB and low-sulfur bituminous coal that inject SO_3 to improve ESP performance. Many of these are units planning to use sorbent injection for mercury control. AmerenUE's Labadie Power Plant is an example of such a plant that fires PRB coal. Labadie presented the opportunity to conduct parametric testing with varying SO_3 concentrations with a given mercury sorbent concentration. The configuration of Labadie also provided the opportunity to evaluate PAC injection both upstream and downstream the APH and SO_3 injection.

Labadie Unit 2 is a Combustion Engineering, tangentially fired, dry-bottom boiler rated at 630 MWe (gross) and fires PRB coal from various mines. For NO_x control, the unit is fitted with low-NO_x burners, Low-NO_x Concentric Firing System (LNCFS™) Level III, and Separated Over-Fire Air (SOFA). No post-combustion NO_x or SO_2 control devices are installed. Flue gas from the Unit 2 economizer is split (50%/50%) between ducts, each with a cold-side Ljungström air preheater. Particulate control is accomplished with three parallel ESPs (A and B were original, and C was retrofitted). These have a combined specific collection area (SCA) of 279 ft^2/kacfm. An SO_3 flue gas conditioning system is used to enhance particulate removal. Type C fly ash is sold to ash marketers, and ash loss on ignition (LOI) levels are driven by their specifications (< 0.5% required). A summary of key operating parameters for Unit 2 is presented in Table 1.

Sorbent was injected at several locations during the DOE Phase II test program (DOE Award Number DE-FC26-03NT41986). In 2005, sorbent was injected downstream of the APH either upstream of the B-ESP or upstream of the C-ESP. In 2006 and 2007, sorbent was injected both upstream and downstream of the APH (downstream to treat the entire unit flue gas stream). The injection grid and mercury measurement locations are shown in Figure 3.

Figure 3. Labadie Unit 2 configuration and sampling locations.



1. Inlet CEM location
2. APH inlet sorbent injection
3. SO_3 injection
4. APH outlet 2006 sorbent injection location
5. APH outlet 2005 sorbent injection location
6. Stack sampling location
7. Stack sampling location
8. CEM trailer location

The injection of SO_3 for flue gas conditioning was a key variable studied during the tests at Labadie. The SO_3 system can be operated in either automatic or manual mode. In automatic mode, the injection rate is varied in response to opacity and gas temperature at the outlet of the APH. In manual mode, the injection rate is fixed at a set percentage and still varied with the APH outlet temperature. The SO_3 injection rate is reported as a percent flow in the plant's distributed control system (DCS). Due to design restrictions, the system can only reliably operate at levels between 30% and 60% of the maximum system injection rate.

Sorbents

Many different sorbents were evaluated at the three electric generating host sites, including:

- Norit DARCO® Hg, the benchmark, lignite-based activated carbon that has been used in most mercury sorbent injection testing to date.
- Norit DARCO® Hg-LH, a lignite-based activated carbon treated with bromine for improved effectiveness in low-halogen flue gases, such as those produced from firing PRB coal.
- Norit DARCO® Hg-E25c, an experimental lignite-based activated carbon treated with alkaline materials to protect the carbon from acid gases in the flue gas.
- Norit DARCO® Hg-E26, an experimental lignite-based activated carbon treated with bromine for improved effectiveness in low-halogen flue gases, and alkaline materials to protect the carbon from acid gases in the flue gas.
- Norit DARCO® Hg-E12, an experimental lignite-based activated carbon chemically treated with basic materials to provide buffering against SO_3 condensation.
- Sorbent Technologies EXP-2, an experimental coal-based treated activated carbon.
- BASF MS200, a mineral-based sorbent.
- Calgon FLUEPAC™-MC PLUS, a bituminous-based activated carbon treated with bromine to enhance mercury capture in the flue gas.

Mercury Measurement

Continuous mercury measurements were obtained using two Thermo Mercury Freedom System™ continuous emissions monitors (CEMs). Additional mercury measurements were made using the Ontario Hydro (OH) method, the modified sorbent trap method (STM), and EPA Method 29 multi-metal test procedure.

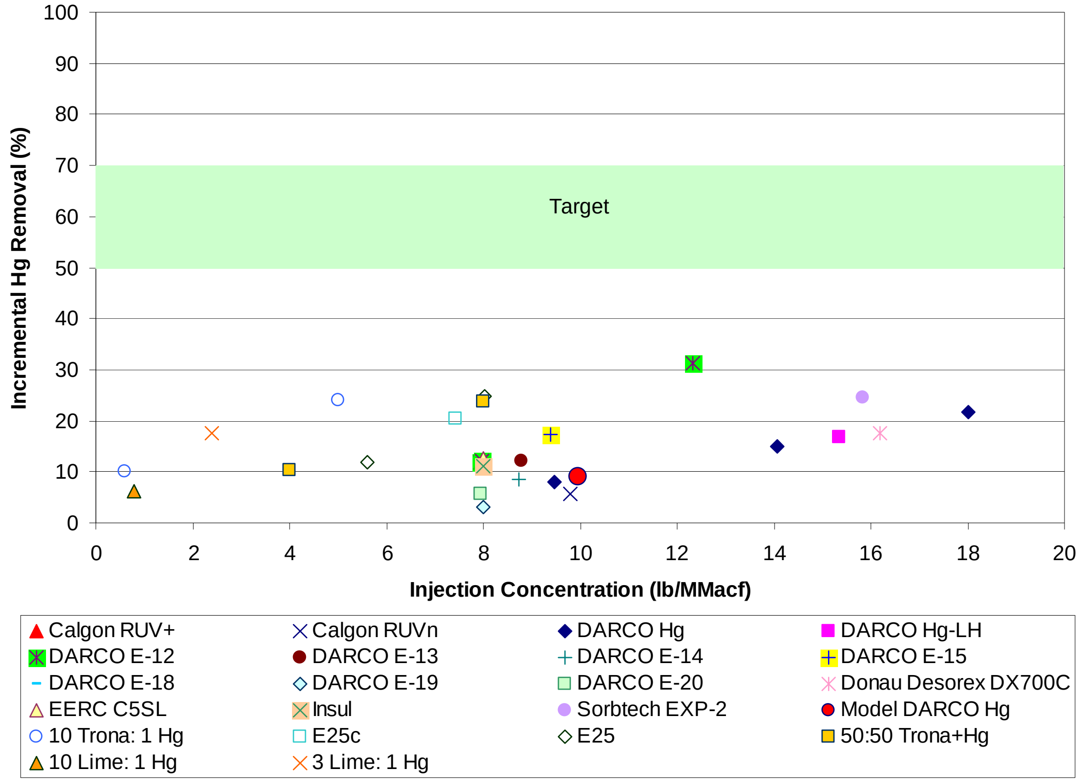
RESULTS AND DISCUSSION

Conesville

In 2006, DOE Phase II mercury control testing was conducted at AEP's Conesville Station. Conesville fires a high-sulfur coal (3 to 4%) and native mercury capture across the ESP is very low, ranging from 0 to 20%. The mercury measured at the inlet to the ESP ranged from 13 to 33 lb/TBtu and the fraction of oxidized mercury at the ESP outlet, upstream of the WFGD, ranged from 60 to 70%. Most of the oxidized mercury is removed in the WFGD.

The native SO_3 concentration at Conesville was typically above 20 ppm. More than 20 sorbents or combinations of sorbents and alkali materials were evaluated for mercury removal at Conesville. Mercury removal efficiency across the ESP was limited for all sorbents across the range of concentrations tested, 9 to 18 lb/MMacf. Injection tests at 9.5 lb/MMacf with DARCO® Hg resulted in only 8% removal. The highest removal attained was 31% using DARCO® E12 at 12 lb/MMacf. The next-highest removal was 25% using Sorbent Technologies EXP-2 at 10 lb/MMacf. Although the injection concentrations varied widely, the results indicate that none of the sorbents were able to achieve the minimum mercury removal goal of 50% at an injection concentration below 10 lb/MMacf. Figure 4 is a compilation of all parametric full-scale test results.

Figure 4. Parametric full-scale test results and Conesville Unit 6.



PSNH Merrimack Station

From 2006 through 2008, ADA-ES conducted mercury control evaluations at PSNH Merrimack Station with funding from a DOE Phase III mercury control program, DOE Award Number DE-FC26-06NT42780, and funding from PSNH. The SCR-generated SO_3 concentration in the flue gas was typically between 15 and 20 ppm. This resulted in very low native mercury removal, usually less than 10%.

The PAC sorbents selected for the parametric tests were Norit's DARCO® Hg, Hg-LH and E26; and Calgon's FLUEPAC™-MC PLUS. The performance of the PAC sorbents was affected by both the SO_3 concentration and the outlet temperature of the APH. The importance of temperature was identified by changing the set point for the APH cold-end average (CEA) temperature. Without modification of either the CEA temperature or the native SO_3 concentration, the mercury removal was limited to less than 22% at injection concentrations up to 8 lb/MMacf for all sorbents tested. When CEA temperature was lowered without the addition of an SO_3 control sorbent, mercury removal with E26 increased to about 31%. During these short parametric tests, no assessment of balance-of-plant impacts was conducted.

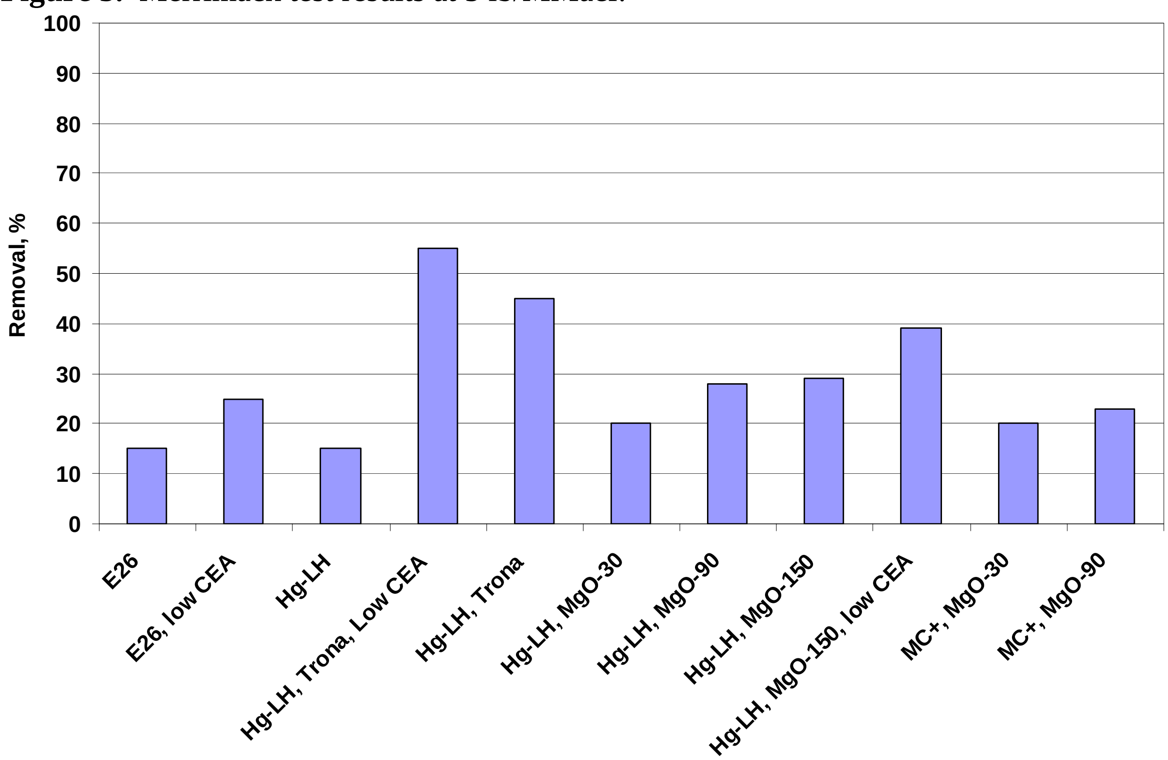
Magnesium oxide (MgO) and sodium sesquicarbonate (trona) were characterized, without ACI, to determine reductions in SO_3 and the impact on ESP performance. Both MgO and trona effectively reduced SO_3 concentrations from the baseline level between 15 and 20 ppm to the 5 to 10 ppm range. SO_3 measurements were made at several locations in the system to determine the effect of trona injection on SO_3 concentration in the gas. These results are presented in Table 2. SO_3 measurements made during this period were collected by Platt Environmental Services, Inc., using a Controlled Condensate modified Method 8A technique.

Table 2. SO_3 Measurements at PSNH Merrimack Station Unit 2.

Test Location	Trona Injection Rate	Gaseous Phase SO_3 (ppm)
Unit 2 SCR Inlet	500 lb/hr	12.13
Unit 2 SCR Outlet		Not Recorded
APH Outlet		6.68
Original ESP Outlet		6.40
Stack Inlet		7.56
Stack Inlet	1000 lb/hr	3.37

Significant improvement in mercury removal was achieved when the SO_3 concentrations were lowered by sorbent injection. Dual injection with trona and PAC provided the most significant increase in PAC effectiveness. While injecting DARCO® Hg-LH at 5 lb/MMacf, mercury removal was 30% and 45% with co-injection of MgO and trona, respectively. Similarly, removal levels were 40% and 55%, respectively, with lower CEA temperatures. The most promising results were obtained by milling the trona and lowering the CEA temperature. During this nine-hour test, more than 70% mercury removal was achieved with DARCO® Hg-LH at an injection concentration of 6 lb/MMacf. The short test duration precluded an assessment of balance-of-plant impacts or long-term sustainability. The highest mercury removal achieved with dual injection of MgO and PAC was 40%. A comparison of sorbent performance at 5 lb/MMacf is presented in Figure 5 for comparison. Additional results are presented in Figure 6.

Figure 5. Merrimack test results at 5 lb/MMacf.



Results from Long-Term Testing at Merrimack

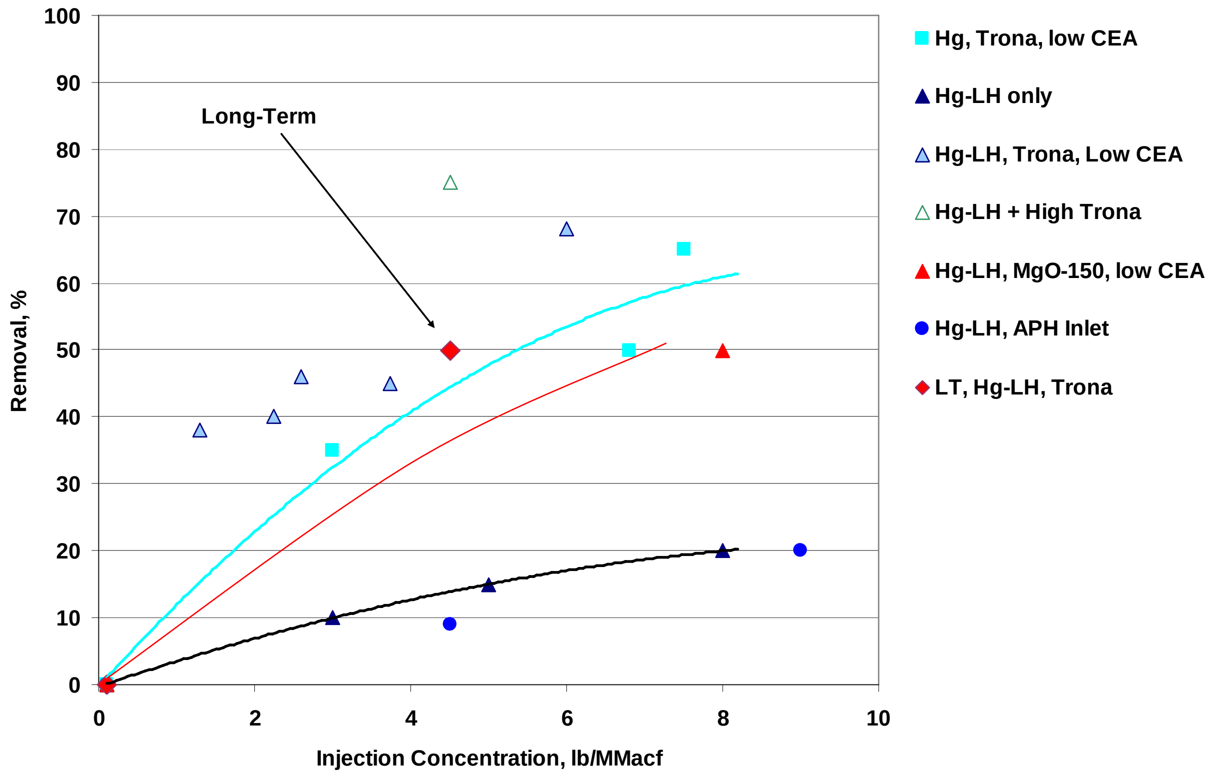
Long-term testing at MK2 began on November 30, 2007. During this test, as-received trona was injected for SO_3 control through four lances between the SCR and the APH at a rate of 550 lb/hr with DARCO® Hg-LH for mercury control at a rate of 6 lb/MMacf (400 lb/hr). Activated carbon was injected between the original and supplemental ESPs via five injection ports. Under these conditions, 50 to 55% mercury removal was achieved but could not be sustained because of balance-of-plant impacts. While injecting trona at 550 lb/hr, the APH differential pressure increased 1.2 inches w.c. in 30 days of injection. Trona injection was stopped on December 27, 2007, and APH differential dropped from 8.1 inches w.c. to 7.7 inches w.c.

When long-term testing resumed on January 23, 2008, opacity spiking occurred with an injection concentration of 6 lb/MMacf. The cause was additional particulate loading to the ESP and associated with changes in ESP operating conditions that could not be altered at that time. Because of this, the activated carbon injection concentration had to be limited to 4.5 lb/MMacf for the rest of the tests.

For the long-term tests, trona injection was increased to 600–700 lb/hr and PAC injection was set at 4.5 lb/MMacf (300 lb/hr). At these injection rates, mercury removal was limited to less than 50%. These results were not as promising as previous results during parametric tests at similar injection conditions. The low mercury removal can most likely be attributed to higher-than-expected, residual flue gas SO_3 concentrations that could have been caused because the trona injection system was partially plugged and not performing as designed. The impact of trona injection on APH differential pressure continued to pose a problem.

During a three-day test in March 2008, the trona injection rate was increased from 500 to 1000 lb/hr to assess the ability to improve mercury removal by lowering the SO_3 concentration. This resulted in an increase in mercury removal from 50% up to 75% at a DARCO® Hg-LH injection concentration of 4.5 lb/MMacf. These short-term results show that optimizing the trona injection lances for better distribution could improve both SO_3 and mercury removal, but the data are insufficient to determine long-term balance-of-plant impacts or sustainability.

Figure 6. Merrimack test results.



Balance-of-Plant Impacts

An evaluation of the effects of injecting alkaline materials upstream of the air preheater on plant operations was included in this project. MgO injection resulted in a rapid deterioration of ESP performance. The ESP performance did not degrade as much or as quickly with trona injection despite the drop in SO_3 concentrations and the subsequent change in ash resistivity (an assumption that was tracked by measuring the pH of the ash). During several of the tests, trona injection resulted in an increase in the pressure drop across the air preheater. One advantage of using MgO is that the fly ash remains a saleable product. Trona imposes more limitations on the plant with regard to fly ash utilization, due to its sodium content.

Another balance-of-plant issue at Merrimack is PAC/ash in the supplemental ESP hoppers. When fly ash containing high concentrations of PAC collects in the hopper, especially when temperatures exceed 350 ºF, there is a risk that the PAC in the ash will begin to smolder.[7] Since PAC was injected downstream of the primary ESP at Merrimack, the ash contained a relatively high fraction of PAC. During the post-shutdown inspection following testing in January 2008, smoldering ash/PAC was discovered in the hoppers of the supplemental ESP. Smoldering ash/PAC mixtures have been reported in the hoppers of TOXECON™ systems (a baghouse located downstream of a primary ESP) when PAC/ash mixtures were left in hot hoppers for extended periods.[8,9] This issue must be resolved for PAC injection upstream of the supplemental ESP to be an option for Merrimack.

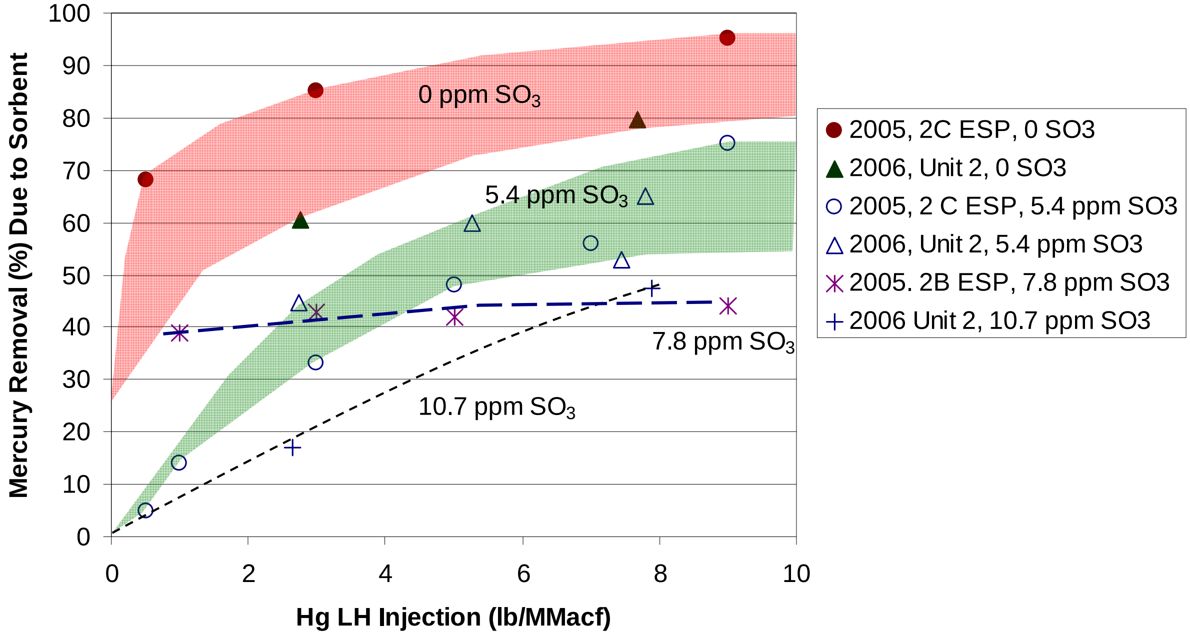
Labadie

DOE Phase II mercury control testing was conducted at Labadie between November 2006 and October 2007. Additional tests were conducted with Ameren funding in 2005. The baseline mercury removal across the ESP was typically less than 15% and most of the mercury was in the elemental form. These results are typical of units firing PRB coal with low unburned carbon in the fly ash, especially those that use SO_3 injection for flue gas conditioning.

The performance of four sorbents injected downstream of both SO_3 injection and the APH outlet were evaluated at Labadie. DARCO® Hg-LH was tested in 2005 and in 2006. In 2006, three additional sorbents, DARCO® Hg-E25c, DARCO® Hg-E26, and BASF MS200 were evaluated. During the 2005 tests, the grid (sorbent injection array) was located either upstream of the B-ESP or upstream of the C-ESP. During 2006 testing, the entire Unit 2 flue gas was treated with sorbent.

A summary of the results with DARCO® Hg-LH is presented in Figure 7. The performance degradation at higher SO_3 injection rates is apparent. For example, at a sorbent injection concentration of nominally 3 lb/MMacf, the mercury removal ranged from 85% across the C-ESP in 2005 with the SO_3 injection turned off, to 17% in 2006 when testing the entire Unit 2 and the SO_3 injection system was set for 10.7 ppm. The 2006 results may be suppressed somewhat due to less than optimal sorbent distribution. The effect of this can be observed when comparing the 2005 and 2006 results with the SO_3 system turned off.

Figure 7. Summary of mercury removal results with DARCO® Hg-LH.

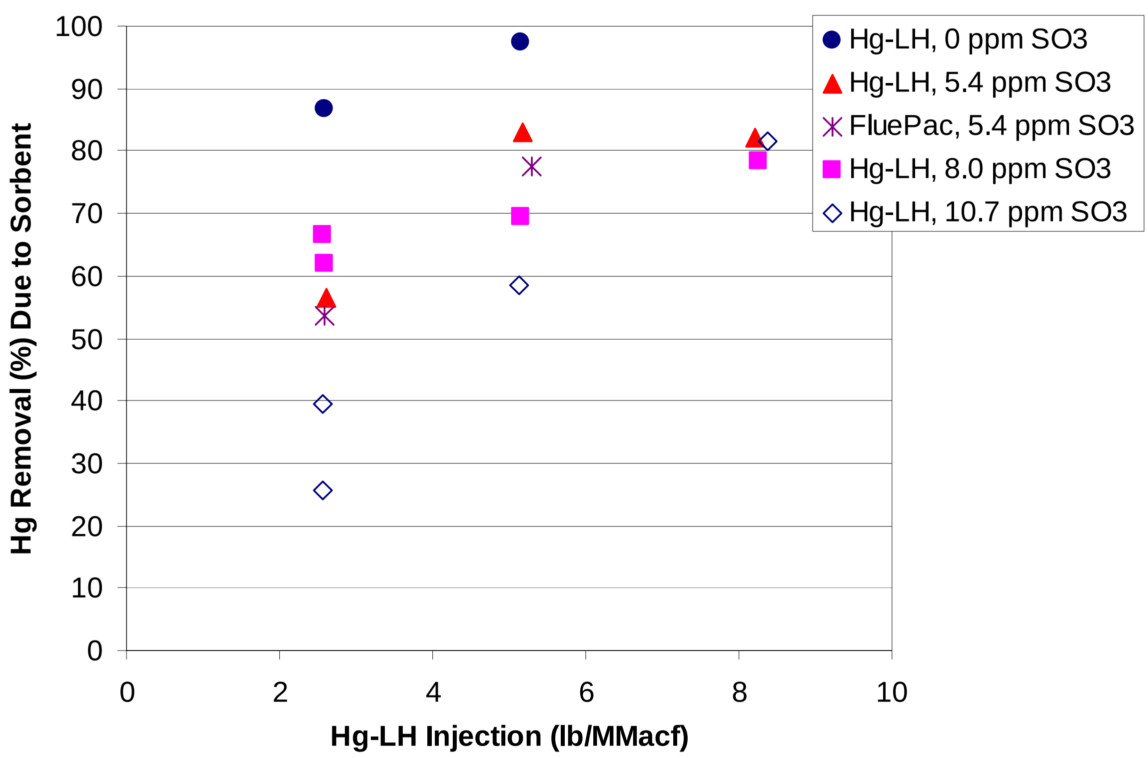


For comparison, the second batch of DARCO® Hg-E26 and the DARCO® Hg-E25c were tested under similar conditions to the DARCO® Hg-LH. The DARCO® Hg-E25c material did not perform as well as the DARCO® Hg-LH. This is not surprising since DARCO® Hg-E25c does not contain the halogen required for optimal performance in PRB flue gas. The bromine-treated

DARCO® Hg-E26 material, however, demonstrated performance (> 60% removal) at 5.4 ppm SO_3 comparable to DARCO® Hg-LH performance with the SO_3 injection system turned off. A review of the ESP operation during DARCO® Hg-E26 testing indicates there was a slight reduction in the inlet field power and an increase in the spark rate in some fields during injection of DARCO® Hg-E26. The mercury removal data suggest that DARCO® Hg-E26 may be an option for improved performance at sites with SO_3 injection, but additional testing is recommended to determine the impact on ESP operation and the resulting particulate emissions from injecting this alkaline-treated material.

The performance of both DARCO® Hg-LH and FLUEPAC™-MC PLUS were evaluated when injected upstream of the APH. The results summarized in Figure 8 show that both materials demonstrate similar performance at this injection location. The data also indicate that there was little performance difference whether the SO_3 system was set at 30% (5.4 ppm) or 45% (8.0 ppm). The sorbent injection concentrations shown in Figure 8 are based on the gas flow calculated at the APH outlet, or particulate collection temperature.

Figure 8. Sorbent injection upstream of the APH.



A comparison of the APH inlet and APH outlet injection test results indicates that these sorbents were more effective when injected upstream of the APH. This may be a result of the additional residence time (roughly 0.5 seconds) or reactions between the sorbents and mercury prior to SO_3 injection.

Balance-of-Plant Impacts

From parametric testing in December 2006, it appears that alkaline materials may absorb some of the SO_3 before it has time to react with the fly ash. During testing with the alkaline-treated materials, a slight increase in TR-set sparking was observed. Due to the increased sparking, overall power to the ESP is lowered but no impact in stack opacity was noted as a result. Only when the SO_3 system was taken out of service did the opacity increase noticeably.

SUMMARY

The ACI test programs conducted at the three test sites—AEP Conesville Unit 6, PSNH Merrimack Station Unit 2, and AmerenUE Labadie Plant Unit 2—indicate that regardless of the source, SO_3 levels in the flue gas will have an impact on the mercury removal performance of PAC. The key program results and potential technologies to minimize or overcome the effect of SO_3 levels include:

- High-sulfur coals
  - The maximum mercury removal achieved at Conesville was 31% (DARCO® E-12 at 12 lb/MMacf).
  - Further testing is required to determine the effectiveness of SO_3 mitigation technologies.
- Low- to medium-sulfur coals
  - SO_3 mitigation technologies have demonstrated significantly improved mercury removal performance when used with ACI.
  - Trona injection upstream of the APH to lower the SO_3 concentration resulted in an increase in the air preheater pressure drop at Merrimack. This issue must be resolved to permit sustained trona injection.
  - Longer-term tests are required to fully evaluate the balance-of-plant impacts of trona injection.
  - PAC/ash collected in hoppers of the supplemental ESP was discovered to be smoldering following approximately two months of continuous injection. This issue must be resolved for PAC injection upstream of the supplemental ESP to be an option for Merrimack.
- SO_3 injection for flue gas conditioning
  - Injecting PAC upstream of the APH improved mercury removal performance at Labadie compared to downstream injection. For example, injecting DARCO® Hg-LH at 5.1 lb/MMacf resulted in mercury removal due to sorbent injection that ranged from 58% with 10.7 ppm SO_3 to over 95% with the SO_3 injection system off. For comparison, 2006 trends from APH outlet injection at the same DARCO® Hg-LH injection concentration indicate nominally 35% removal with 10.7 ppm SO_3 to 75% with the SO_3 injection system off. APH outlet results from 2005 indicate nominally 90% mercury removal with the SO_3 injection system off.
  - Some treated PACs, specifically DARCO® Hg-E26, the bromine-treated carbon with alkali, demonstrated encouraging mercury removal potential. Impacts on ESP operation for PAC treated with alkaline materials will need to be evaluated further.
  - *One approach currently being investigated for flue gas conditioning, but not included in this program, is to substitute the SO_3 with an alternate gas conditioning agent that does not impact PAC performance, or an alternate ESP design that does not require conditioning.*

The use of sorbent injection for the control of higher-SO_3 flue gas mercury remains a significant challenge, especially for high mercury removals. Although several approaches to improve sorbent performance show promise, to date, none of the sorbents or supplemental approaches tested have demonstrated the ability to maintain consistent high mercury removals in high-SO_3 flue gas without balance-of-plant impacts. It is uncertain at this point whether more SO_3-tolerant sorbents or further refinement of the above approaches can eventually achieve high mercury removals. In any case, the cost of mercury control with sorbents in high-SO_3 environments will likely be quite high in comparison to lower-SO_3 environments because of the increased amounts of sorbents needed and the complexity of the supplemental systems. Other approaches besides sorbent injection (such as co-benefit using SCR+WFGD) may be less costly. The co-benefit approaches have to date not consistently achieved > 90% mercury removals and need to be developed further as well. The above observations apply to ESP-equipped units. It is uncertain if baghouses can achieve high mercury removals with sorbent injection in high-SO_3 bituminous coal flue gases, especially with alkali co-injection. Baghouses are not normally used in high-SO_3 environments due to reduced bag life.

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