Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update

by

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Glossary of Terms

ACI	Activated Carbon Injection
APC	Air Pollution Control
APPCD	Air Pollution Prevention and Control Division
B-PAC	Brominated Powdered Activated Carbon (product name from Sorbent Technologies Corp, Twinsburg, OH)
CFD	Computational Fluid Dynamics
CS-ESP	Cold-side Electrostatic Precipitator
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
E-3	Product name of Norit Americas' halogenated powdered activated carbon
FF	Fabric Filter (baghouse)
FGD	Flue Gas Desulfurization
FGD (Norit)	Norit FGD is the product name for an activated carbon produced by Norit Americas
HS-ESP	Hot-side Electrostatic Precipitator
ICR	Information Collection Request
L/G	Liquid-to-Gas ratio
LSFO	Limestone Forced Oxidation scrubber
MEL	Magnesium Enhanced Lime scrubber
NETL	National Energy Technology Laboratory
NOx	Nitrogen Oxides
ORD	Office of Research and Development
PAC	Powdered Activated Carbon
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
PPPP	Pleasant Prairie Power Plant
PRB	Subbituminous coal mined in Wyoming's Powder River Basin
PS	Particulate Scrubber
R&D	Research and Development
RD&D	Research, Development, and Demonstration
SCA	Specific Collection Area
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SDA/FF	Spray Dryer Absorber with downstream Fabric Filter
SEA	Sorbent Enhanced Additive
STS	Sodium Tetrasulfide
TBD	To Be Determined
UBC	Unburned Carbon

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INTRODUCTION

Coal-fired power plants in the U.S. are known to be the major anthropogenic source of domestic mercury emissions.[1] The Environmental Protection Agency (EPA) has recently proposed to reduce emissions of mercury from these plants.[2] In March 2005, EPA plans to promulgate final regulations to reduce emissions of mercury from coal-fired power plants. To help inform this regulatory effort, a White Paper on the status of mercury control technologies for electric utility boilers was released in February 2004 by EPA's Office of Research & Development.[3] Subsequently, much new information has become available on these technologies. This White Paper has been prepared to document the current status of mercury controls and help inform the upcoming regulatory action. As will be discussed, control of mercury emissions from coal-fired boilers is currently achieved via existing controls used to remove particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_X). This includes capture of particulate-bound mercury in PM control equipment and soluble mercury compounds in wet flue gas desulfurization (FGD) systems. Available data also show that use of selective catalytic reduction (SCR) NO_X control enhances the concentration of soluble mercury compounds in flue gas from some coal-fired boilers and results in increased mercury removal in the downstream wet FGD system. Controls are also under development specifically for the purpose of controlling mercury emissions. This White Paper will focus on the control options that have been, or are currently being, used/tested at power plants.

THE U.S. POWER SECTOR

The U.S. fleet of coal-fired generating assets covers a range of coals and plant configurations. The coal and plant characteristics impact the effectiveness of various mercury control methods at these plants. The U.S. coal-fired power plants typically burn one of three types of fuel: (1) bituminous coal (also referred to as "high rank" coal), (2) subbituminous coal, and (3) and lignite (subbituminous coal and lignite are referred to as "low rank" coals). Some of the characteristics of interest for these coal types are given in Table 1.[4]

The current capacity of U.S. coal-fired power plants is just over 300 GW and includes a wide range of combinations of installed air pollution control (APC) configurations. In response to current and proposed NO_X and SO_2 control requirements, additional NO_X control and flue gas

desulfurization (FGD) systems are expected to be installed and more widely used in the future (see Figures 1 and 2 below). Over half of the U.S. coal-fired capacity is projected to be equipped with selective catalytic reduction (SCR) and/or FGD technology by 2020. Table 2 shows the current and projected coal-fired capacity by APC configuration.[5]

BEHAVIOR OF MERCURY IN COAL-FIRED ELECTRIC UTILITY BOILERS

Mercury may be present in the flue gas in several forms. The specific chemical form – known as the speciation – has a strong impact on the capture of mercury by boiler air pollution control (APC) equipment.[*] Mercury may be present in the flue gas as elemental mercury vapor (Hg^0), as a vapor of an oxidized mercury species (Hg^{2+}), and as particulate-bound mercury (Hg_p).

Mercury is present in coal in trace amounts (approximately 0.1 ppm on average). Research by the U. S. Geological Survey indicates that much of the mercury in coal is associated with pyrite. Other forms of mercury that have been reported are organically bound, elemental, and in sulfide and selenide minerals.[6] During combustion the mercury is released into the exhaust gas as elemental mercury vapor, Hg^0. This vapor may then be oxidized to Hg^{2+} via homogeneous (gas-gas) and heterogeneous (gas-solid, surface catalyzed) reactions.

The primary homogeneous reaction is that with gas-phase chlorine. As the combustion exhaust gases exit the boiler and cool, thermodynamic equilibrium shifts to favor formation of $HgCl_2$ vapor. The temperature window where this transformation occurs varies, based upon coal conditions, from about 620 °F to 1250 °F.[7] At the temperature after the last heat exchanger, normally around 300 °F, one would expect all of the mercury to be in the oxidized form if the reactions went to equilibrium. However, gas-phase mercury oxidation is slow and highly dependent upon the amount of chlorine[8] in the flue gas and, in practice, the amount of oxidized mercury in the flue gas can range from a few percent to over 90%. Therefore, the transformation of elemental mercury to oxidized mercury is kinetically limited, i.e., the chemical reactions associated with mercury oxidation do not go to completion.

Heterogeneous (gas-solid, surface catalyzed) mercury oxidation is more complex and depends upon the availability of surfaces having electrophyllic groups that attract the electron-rich Hg^0 atom. The heterogeneous reactions occur mostly on fly ash surfaces or boiler surfaces, especially if the fly ash contains high amounts of unburned carbon. A proposed heterogeneous oxidation mechanism indicates the chlorination of carbon by HCl is a first step toward heterogeneous oxidation of Hg^0 to $HgCl_2$, and adsorption of the mercury onto the carbon.[9] The mercury that is adsorbed onto solid surfaces, such as fly ash or unburned carbon, is the particulate-bound mercury, Hg_p, which can be captured by downstream PM control devices. Hence, fly ash characteristics – especially carbon - as well as coal chlorine content play an important role in mercury speciation and capture.

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[*] In general it is thought that Hg^0 will not be removed by pollution control equipment without first converting it to another form of mercury – either Hg^{2+} or Hg_p However, there is also the possibility for interaction between a charged surface and the elemental mercury vapor. These interactions may be in the form of electrostatic, van de Waals, and polarization energies (elemental mercury vapor is polarizable).

Other flue gas species – especially SO_3 and H_2O – have also been shown to affect mercury speciation, tending to suppress Hg^0 oxidation to Hg^{2+}. This is due to competition for active sites on the surface of carbon or other flue gas solids. In general, bituminous coals tend to have higher chlorine contents and also tend to produce higher levels of unburned carbon (UBC) in the fly ash. As a result, the flue gas from the burning of bituminous coals tends to contain higher amounts of Hg^{2+} species while that of subbituminous and lignite coals tends to contain more Hg^0 vapor.

MERCURY REMOVAL BY EXISTING CONTROLS

Mercury may be captured as a cobenefit of PM controls and SO_2 controls, as well as through mercury-specific control technologies. The degree of this cobenefit can vary significantly depending upon the type of coal being burned and the specific control technology configuration. This native capture (i.e., mercury capture without add-on mercury-specific control technology) is seen in Figure 3, which shows mercury removal rates from EPA's Information Collection Request (ICR) for three different coal types and APC configurations in use at power plants. There are some important trends in this figure.

- For the same APC configuration, the average mercury removal for bituminous coal was greater than that for other coals.
- Mercury removal for a fabric filter (FF) was significantly higher than those for a cold-side ESP (CS-ESP) or hot-side ESP (HS-ESP) for both bituminous and subbituminous coals (no FF data for lignite coals).
- Average mercury removal for bituminous coal-fired boilers with Spray Dryer Absorber and FF (SDA/FF) was very high (over 95%); for subbituminous coal-fired boilers with the same control configuration mercury removal was considerably less (about 25%), which was actually less than for a FF alone (about 75%).
- In several cases there was a high level of variability in capture efficiency.

The tendency for a higher native mercury capture from boilers burning bituminous coal is likely a result of the higher chlorine content in the coal and of the tendency of these coals to produce higher levels of unburned carbon in the flue gas. Both factors will contribute to greater levels of mercury as Hg^{2+} and Hg_p, which are easier to capture in existing air pollution control equipment than Hg^0.

The improved mercury capture for plants using FF as compared to those using ESPs can be explained by the increased contact the gas experiences with fly ash and unburned carbon (UBC) as those accumulate as a filter cake on the FF. The filter cake acts as a fixed-bed reactor and contributes to greater heterogeneous oxidation and adsorption of the mercury.

The poor removal of mercury by SDA/FF on low rank coals can be explained by the fact that much of the HCl in the flue gas is captured by the SDA, leaving inadequate HCl at the FF to participate in the oxidation and capture of Hg^0. For bituminous coals, usually having a higher percentage of mercury as Hg^{2+} due to higher coal chlorine and UBC, this HCl stripping effect appears not to be important.

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The high variability of mercury capture for several situations indicates that for several cases there are other important factors besides coal rank and APC configuration. For example, the bituminous coal with CS-ESP data covers a range of coal chlorine, fly ash carbon, ESP inlet temperature and coal sulfur levels – all of which can impact mercury capture efficiency. So, even within any classification of coal or control technology, there may be a significant amount of variability in the native mercury capture.

Mercury Capture in PM Controls

As seen earlier in the ICR data (Figure 3), a FF can be very effective for mercury capture, especially for bituminous coals, but for subbituminous coal as well. However, this FF-only configuration represents less than 5% of the U.S. coal burning capacity and is expected to decline in the next 15 years (see Table 2).

The native mercury capture in plants having only CS-ESP or HS-ESP was shown to be much less effective when compared to those with the FF-only configuration. This is because there is much less contact between gaseous mercury and fly ash in ESPs. Also, HS-ESPs operate at higher temperatures at which capture in fly ash is not effective. As with the FF-only configuration, the ESP-only configuration is expected to become less common (though still approximately 20% of the total capacity) in the next 14 years with the expected installation of NO_X and SO_2 controls.

Mercury capture in PM control devices becomes much more important with the injection of sorbents to the flue gas stream. This is discussed in great detail later in this document.

Mercury Capture in FGD Systems

FGD systems typically fall into one of two broad categories. The wet FGD systems include the common limestone forced oxidation (LSFO) scrubber and the magnesium-enhanced lime (MEL, or "mag-lime") scrubber. The dry FGD systems are typically spray dryer absorbers (SDA), which are usually installed in combination with a FF (SDA/FF).

Mercury Capture in Wet FGD Systems
Mercury in the oxidized state (Hg^{2+}) is highly water soluble and thus would be expected to be captured efficiently in wet FGD systems. Data from actual facilities has shown that capture of over 90% Hg^{2+} can be expected in calcium-based wet FGD systems, though there are cases where significantly less has been measured. It has been suggested that this is primarily a result of scrubber equilibrium chemistry and good predictive capability for total mercury capture in wet FGD systems using a thermochemical equilibrium model has been discussed.[10] It has also been shown that under some conditions Hg^{2+} will be reduced to Hg^0 and the mercury will be reemitted.[11] In some cases, the reduction of Hg^{2+} to Hg^0 and subsequent re-emission have been abated with the help of sulfide-donating liquid reagent.[7] So this limiting FGD scrubber chemistry and reemission of mercury may result in Hg^{2+} capture that is significantly less than 90%. Experience has shown that Hg^{2+} reduction and reemission may be more difficult to avoid in magnesium-enhanced lime (MEL) scrubbers due to the much higher sulfite concentration in these systems.[12]

The effect of scrubber chemistry and operating conditions on mercury emissions exhibited in Figure 4, which shows the measured mercury emissions as liquid-to-gas ratio (L/G) was varied on a 100 MMBtu/hr pilot facility with inlet mercury concentration in the range of about 10-25 µg/dsm.[3] Higher L/G resulted in lower outlet mercury emissions which has implications for wet FGD type – Limestone Forced Oxidation having higher L/G than Magnesium Enhanced Limestone (MEL) wet FGD.

Figure 5 shows the mercury removal for various FGD systems reported by different sources, including mercury removal with SCR in operation.[12, 13, 14, 15] All results, except those on the far right of the figure, are from wet FGD systems. There isn't enough data in this figure to show clear trends between various wet FGD system types. But, more detailed examination of scrubber operating characteristics would likely reveal that the scrubber chemistry may be optimized to achieve high mercury removal as well as high SO_2 removal.[10, 11, 12] In any event, it is clear that the use of SCR and FGD combination consistently yielded mercury removal of nearly 90% in each of the applicable cases shown in Figure 5. In a comparable study partially funded by the U.S. DOE, 6 boilers fired with bituminous coal and equipped with SCRs, ESPs, and wet FGDs were shown to reduce total mercury emissions by 85%.[16] SCR impact on mercury speciation is discussed in the following section.

Oxidation of Hg^0 to Hg^{2+} by SCR Catalysts
Because Hg^{2+} can be captured much more effectively than Hg^0 in wet FGD systems, methods to increase the amount of Hg^{2+} upstream of the wet FGD should improve mercury capture in the wet FGD system. Under certain conditions, SCR catalysts have been shown to promote the oxidation of Hg^0 to Hg^{2+}, particularly for bituminous coal. The impact of SCR on mercury oxidation is being investigated in two series of field tests: (1) EPRI-EPA-DOE sponsored field tests[15] and (2) DOE sponsored tests being conducted by CONSOL.[13] The results of field test programs suggest that oxidation of elemental mercury by SCR catalyst may be affected by the following:[15]
- The coal characteristics, especially the chlorine content
- The amount of catalyst used to treat the gas stream
- The temperature of the reaction
- The concentration of ammonia
- The age of the catalyst

The above factors have significance regarding the potential benefits of SCR on mercury capture for bituminous coals vis-à-vis subbituminous or lignite coals. A comparison of the effects of SCR shows that oxidation of Hg^0 to Hg^{2+} is greater for bituminous coals than for subbituminous coals (no data is available for lignite). In fact, in most cases the use of SCR resulted in about 85 – 90+% mercury in the oxidized form when firing bituminous coals. Figure 6 shows data from the EPRI-EPA-DOE field test, the DOE-CONSOL field tests and from field tests conducted at Dominion Resources Mount Storm Unit 2.[12] In particular, the figure reflects the percent Hg^{2+} measured at the inlet of the CS-ESP for boilers equipped with SCR.[12, 13, 15] Where data is available with the SCR off-line, it is also shown. In every bituminous coal case except S3, the percent Hg^{2+} increased. In the case of S3, a sampling artifact is suspected.[11] In the case of the PRB-fired unit, Hg^{2+} concentration remained very low. It should be noted that there may be some uncertainty associated with speciated mercury measurements upstream of a PM control

device. This is because PM in the extracted sample may cause oxidation of elemental mercury in that sample.

It would be desirable to increase the oxidation of mercury by SCR when firing subbituminous coals to levels approaching the oxidation levels of bituminous coals. To investigate if this was possible, Senior and Linjewile[17] compared the results of thermochemical equilibrium calculations of mercury species concentration to full-scale and pilot test results. There was good correspondence between the results of the calculations and test results, suggesting that oxidation of Hg^0 to Hg^{2+} with SCR when firing subbituminous coal is limited by equilibrium rather than by kinetics. Hence, an improvement in catalytic oxidation of Hg^0 to Hg^{2+} with SCR on boilers firing low-rank coals is not possible without a change in flue gas chemical composition (such as from a higher chlorine in coal) or a lower catalyst temperature.

Senior and Linjewile also found that, when ammonia was injected, oxidation of Hg^0 to Hg^{2+} tended to drop somewhat.[17] This suggests that the presence of ammonia may interfere with mercury oxidation on the catalyst. Another concern regarding the use of SCR for mercury oxidation is that of the catalyst age (i.e., as the SCR catalyst ages, the oxidation of mercury may decline due to a loss in catalyst activity). Although field tests of catalyst oxidation between years did not show a significant change in mercury oxidation, it is thought that the age of this catalyst may not be adequate to show a significant change. Most SCR systems installed on U.S. facilities have been operating for only a few years, so the effect of catalyst age on mercury oxidation may not be apparent yet.

Mercury removal by SDA/FF systems
As shown in Figure 3, mercury is very efficiently removed by SDA/FF combinations when used on bituminous coal-fired boilers – an average of approximately 95%. Mercury – mostly in the form of Hg^{2+} at the inlet of the SDA with bituminous coals - is captured in the filter cake of the FF. However, mercury capture in SDA/FF systems tends to be much less in low-rank coals. For low-rank coals, the low capture of mercury by SDA/FF systems is believed to be a result of the scrubbing of HCl in the SDA, which makes oxidation and capture of mercury (mostly in the form of Hg^0 for these coals) in the downstream FF less effective. In fact, Figure 3 shows higher mercury capture by FF when firing subbituminous coal than mercury capture by SDA/FF. This is believed to be a result of the SDA scrubbing effect in removing HCl that could otherwise be available to react on the FF.

Data/Science Gaps and Associated Recommendations

To meet regulatory time lines, research and development (R&D) efforts should be focused on those areas that are likely to affect the largest number of boilers or are likely to significantly impact the ability of a class of boilers to reduce mercury. The following are items (in no particular order) where there is a shortage of data or where knowledge remains inadequate:

- Public information regarding mercury oxidation across SCR catalysts when lignite coal is fired could not be found.
- The role ammonia plays in interfering with mercury oxidation should be studied in greater detail. If ammonia interferes with mercury oxidation in the manner previously

suggested, then SCR effectiveness in oxidizing mercury may be reduced as the catalyst ages.

- The speciation of mercury at the inlet of the SCR, or inlet of the PM control device (in the case where SCR is not installed), remains difficult to predict because the processes that govern mercury speciation in the boiler are not yet adequately understood. A better understanding of this would improve the ability to predict mercury removal performance of FGD and other air pollution control equipment.
- The understanding of mercury oxidation across SCRs may best be conducted with coordinated laboratory/pilot and field testing. Field testing alone does not provide adequate control of conditions to understand this phenomenon.
- More information on the effectiveness of mercury control with wet scrubbers on lignite or subbituminous fired boilers is needed.
- Reduction of oxidized mercury in wet FGD and subsequent re-emission requires enhanced understanding.
- Parallel efforts to improve measurement and data collection accuracy and to reduce the effort necessary for speciated measurements of mercury are critical. These are very challenging, labor intensive measurements. Significant progress has been made over the last few years to improve the reliability and accuracy of on-line measurement systems. However, accurate and dependable measurement of mercury at very low concentrations will be needed to prove the efficacy of mercury control systems.
- An improved understanding of the behavior of mercury in the boiler and air pollution control system may offer insights to addressing operational variability. Modeling supported by verification testing should be pursued to develop these capabilities.
- Efforts examining the potential for leaching of Hg and other metals (e.g., Se, As) from coal combustion residues (fly ash, scrubber sludge, etc.) are ongoing. Based on limited number of samples, results of these efforts have indicated that leaching of mercury from flyash and flyash-sorbent mixtures does not appear to be of concern. However, the potential for leaching of Hg and other metals should continue to be evaluated over a range of coal combustion residue types and their management practices.
- The potential for release of mercury in processes involving beneficial use of coal combustion residues (e.g., wallboard production and other high temperature processes) should be evaluated.

APPROACHES FOR ENHANCING MERCURY CAPTURE BY SO_2 OR PM CONTROLS

Important factors that have been found to influence the mercury capture as a cobenefit of other APC equipment include the coal characteristics, especially the chlorine content, and the carbon content of the fly ash. Therefore, efforts to improve capture efficiency of existing equipment have been directed primarily at several approaches: fuel blending, addition of oxidizing chemicals, controlling UBC content of the fly ash, addition of a mercury-specific oxidizing catalyst downstream of the PM control device. Many of these options are shown in Figure 7.

Fuel Blending

Blending of small amounts of bituminous coal with subbituminous or lignite coal may provide some benefit to capture of mercury by existing equipment. Coal blending has been shown to affect UBC and mercury removal. For example, Sjostrom showed that at Holcomb Station, a 360 MW, PRB[a]-fired boiler equipped with SDA/FF for SO_2 and PM control, vapor phase mercury capture across the SDA/FF system could be increased from less than 25% to nearly 80% by blending small amounts of western bituminous coal with the PRB coal.[18] Since mercury removal of SDA/FF systems firing 100% bituminous coals has been shown to be about 90% or greater, this permits mercury removal performance approaching that of bituminous coals while firing mostly PRB. The effectiveness of this approach in improving cobenefit mercury controls is likely to be very facility-specific. The long-term effects of blending fuels would need to be evaluated for each application. Blending may change boiler slagging/fouling characteristics or the performance of APC equipment.

Addition of Oxidizing Chemicals

The addition of chlorine to the fuel or injection into the flue gas is another approach that is being tested for enhancing intrinsic capture of mercury. At Laskin 2 (firing PRB) and at Stanton 10 (firing North Dakota lignite), chlorine salts were added to the fuel to assess the impact of increasing fuel chlorine on mercury oxidation and capture. Laskin 2 is equipped with a Particle Scrubber (PS) and Stanton 10 with a SDA/FF. In both cases, mercury oxidation increased, although for some salts the mercury capture did not increase. In the case of Laskin, opacity was observed to increase as a result of salt addition and in the case of Stanton 10, pressure drop across the FF increased. Long-term effects, such as corrosion, plugging, impacts on combustion equipment could not be assessed during the short-term parametric tests.[19] Therefore, the use of coal additives offer some promise at improving mercury capture; however, they may have other impacts that need to be evaluated.

Increasing UBC in Fly Ash

Carbon in the fly ash has been shown to be an important factor in mercury capture by PM control equipment. For example, at Salem Harbor #1, which fires bituminous coal and has a CS-ESP, mercury removal rates over 80% were measured on some occasions. These were attributed in large part to the very high carbon content in the fly ash – on the order of 15% or more and sometimes around 30%.[20] As a result of this phenomenon, it is possible to optimize the trade off between higher fly ash carbon and improved mercury control by adjusting combustion conditions or fuels. Since unburned carbon is unavailable for the production of steam and electricity following combustion there is a trade-off between the overall plant efficiency versus mercury adsorption. In general, this approach may be employed at any plant with a CS-ESP or FF, but may be more applicable to those with dry bottom boilers. However, the carbon content in the fly ash may need to be kept within acceptable limits due to constraints with ESP or FF performance or opacity. For plants with HS-ESPs, this approach is not expected to be effective because the carbon is not very effective in capturing mercury at HS-ESP temperatures. Finally, other impacts

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[a] PRB coal is a commonly used subbituminous coal that is mined in the Powder River Basin (PRB) in Wyoming.

of increased UBC (e.g., waste disposal and byproduct use) could also pose additional constraints on use of this mercury control approach.

Mercury-Specific Catalysts

Enhancing capture by wet FGD processes is possible if Hg^0 can be oxidized to Hg^{2+}. Research efforts are underway to evaluate catalysts that are installed upstream of the wet FGD or injection of oxidizing chemicals upstream of the FGD. These approaches are undergoing full-scale evaluation. Important concerns involve longevity of the catalyst and the long-term effects of oxidizing chemicals on downstream equipment.

Improvement of Mercury Capture in Wet FGD

As mentioned earlier the amount of mercury that is captured in the wet FGD system is limited by the amount of oxidized mercury entering the scrubber and by the scrubber equilibrium chemistry. The mercury removal performance of the scrubber may also decrease if absorbed Hg^{2+} is reduced and reemitted as Hg^0 vapor.

Evaluation of ICR Data
An analysis of the EPA ICR data was conducted in order to evaluate reemission from the FGD system. The data for systems with CS-ESP/wet FGD and HS-ESP/wet FGD were evaluated. The increase of the amount of elemental mercury across the entire system was assumed to be the result of Hg^{2+} mercury that was absorbed in the wet scrubber and subsequently reduced and reemitted as Hg^0 vapor. The data[*] was evaluated using the following equation:

$$\% \ Hg^0 \ \text{increase} = \frac{\left(Hg^0_{out} - Hg^0_{in}\right)}{\left(Hg^{Total}_{in}\right)} x100$$

For the CS-ESP/wet scrubber configuration there was a 5% increase in Hg^0 across the system for bituminous (1 unit). The subbituminous (3 units) and lignite (2 units) plants showed a 4-50% and 12-21% decrease of Hg^0 across the system, respectively.

For the HS-ESP/wet scrubber configuration, however, there was a greater tendency for increasing Hg^0 across the system. For bituminous plants (2 units) the Hg^0 increased by 2-12%, while the subbituminous plants (4 units) ranged from a 30% decrease up to 67% increase (note: 3 of the 4 subbituminous units showed a net increase of elemental mercury across the APC system). There were no lignite plants with the HS-ESP/wet scrubber configuration.

Field Testing
Babcock & Wilcox (B&W) and McDermott Technology, Inc. completed field tests at two commercial coal-fired utilities with wet FGD systems. The work was funded by DOE/NETL, the Ohio Coal Development Office, and B&W. The test sites were (1) Michigan South Central Power Agency's (MSCPA) 55 MW Endicott Station and (2) Cinergy's 1300 MW Zimmer

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[*] Only data where the inlet and outlet flows were within +/- 30% were used in this analysis. Also, cases where there was a net increase of Hg^{2+} across the system were not used in this analysis.

Station. Endicott Station uses a limestone forced oxidation (LSFO) wet FGD system, while Zimmer Station using Thiosorbic® Lime (magnesium enhanced lime, MEL) and ex situ oxidation. High-sulfur bituminous coal was burned at both locations. The results of the tests were as follows:[21]

At the Endicott Station, total mercury removal across the wet FGD system during the 4-month long tests ranged from 76% to 79%. Most of the oxidized mercury present in the flue gas was removed in the scrubber system (approximately 96% removal). No increase in elemental mercury concentration across the scrubber was observed. This indicated that the control technology was successful in maintaining high levels of oxidized mercury removal and also simultaneously suppressing mercury reemission.

Following the Endicott test program, a 15-day verification test was performed at the Zimmer Station. The average total mercury removal across the wet FGD system averaged approximately 51% during this test. Lower removal of oxidized mercury was observed, as compared to that measured at Endicott (87% vs. 97%). Additionally, the elemental mercury concentration increased across the wet FGD system, by approximately 40%. This indicated that the technology was less effective in removing oxidized mercury and ineffective in suppressing reemission of captured mercury from the scrubber.

In order to evaluate the individual and cumulative role of SCR catalyst, ammonia injection and chemical additive on the speciation and removal in a limestone forced oxidation (LSFO) scrubber, testing was conducted at Dominion Resources Mount Storm power plant (Unit 2, 563 MW, firing medium-sulfur Eastern bituminous coal).[12] Baseline mercury removal testing was completed under several scenarios including full flue gas bypass of the SCR and flue gas flowing through the SCR with and without ammonia injection. After baseline testing, a chemical additive (sodium hydrosulfide, NaHS) was injected into the scrubber recirculation pumps to evaluate its impact on oxidation and reemission of elemental mercury. The results of the tests are given in Table 3.

The results showed that during testing with the SCR bypassed and no injection of the additive, the scrubber still captured greater than 90% of the oxidized mercury (71% total mercury). However, there was reemission of Hg^{2+} as Hg^0 vapor as indicated by the approximately 15% net increase of elemental mercury across the scrubber. Under the same conditions (SCR bypassed) but with the chemical additive injected, there was again greater than 90% capture of the Hg^{2+} and approximately 30% capture of Hg^0 (actually Hg^0 that was oxidized and retained as Hg^{2+}). There was also an increased total mercury removal, at 78%. In tests where the flue gas was directed through the SCR, both with and without chemical additive injected into the scrubber recirculation pumps, the removal of Hg^{2+} increased to greater than 95% and the total mercury removal increased to greater than 90%.

These results indicate the effectiveness of the chemical additive (a NaHS injection technology that has been patented by B&W) in suppressing the reemission of elemental mercury. The tests also showed that the presence of the SCR catalyst significantly impacted the mercury speciation profile at the inlet of the wet scrubber, causing oxidation of the remaining elemental mercury. The oxidized mercury was effectively removed by the wet scrubber.[12]

Data and Science Gaps and Associated Recommendations

For each of these methods used to enhance the removal of mercury by existing equipment, the effectiveness under the range of operating conditions, and range of coals that a plant may operate with, would need to be evaluated. Long-term impacts to the plant, particularly corrosion with approaches that involve chemical additives to the flue gas or fuel, should be examined. Impacts to other air pollution control devices must also be considered.

The effectiveness of oxidation catalysts over an extended period of exposure to flue gas may need to be understood better before such technology can be commercially implemented.

MERCURY CONTROL BY SORBENT INJECTION

Unlike the technologies described earlier, where mercury removal was achieved as a cobenefit with removal of other pollutants, mercury control via injection of sorbent materials into the gas stream of coal-fired boilers is under development. Injection of dry sorbents, such as powdered activated carbon (PAC), has been used for control of mercury emissions from waste combustors and has been tested at numerous utility units in the United States. However, sorbent injection experience on waste combustors may not be directly transferable to coal-fired electric utility boilers due to the following reasons.

1. The concentration of mercury in the flue gas of waste combustors is an order of magnitude higher than for coal-fired boiler systems. Consequently, the amount of mercury captured per unit mass of carbon injected will, in general, be higher in waste combustors compared to coal-fired boilers.

2. Typically, the flue gases of waste combustors have higher chlorine concentrations than those found in flue gases of coal-fired utility boilers. Since performance of ACI in situations with low levels of chlorine in the flue gas may be adversely affected, ACI performance on waste combustors may, in general, not be equivalent to that on coal-fired boilers.

3. In general, coal-fired power plants are much larger in size compared to waste combustors. For example a large municipal waste combustor may be about the same size as a small, 40-50 MW, coal-fired plant. Accordingly, duct dimensions, generally, are much larger in coal-fired plants compared to those at waste combustors. Since mixing of injected AC and flue gas in the duct affects mercury capture performance, design of AC injection systems may, in general, be more involved for coal-fired boilers.

Dry sorbent may be injected into the ductwork upstream of a PM control device – normally either an ESP or FF. In some cases, an FGD (dry or wet) system may be downstream of the sorbent injection point. Usually the sorbent is pneumatically injected as a powder. The injection location will be determined by the existing plant configuration and whether additional downstream PM control equipment, such as a FF, is retrofit. For example, to segregate collected fly ash from collected sorbent it may be beneficial to retrofit a pulse-jet FF (PJFF) downstream

of an existing ESP and inject the sorbent between the ESP and the PJFF. This type of particulate removal configuration is called a Compact Hybrid Particle Collector (COHPAC[TM]) and when combined with sorbent injection is called Toxic Emission Control (TOXECON[TM]). Therefore, for boilers currently equipped only with PM control devices, implementing sorbent injection for mercury control would likely entail either:

- injection of powdered sorbent upstream of the existing PM control device (ESP or FF); or
- injection of powdered sorbent downstream of the existing ESP and upstream of a retrofit PJFF, the TOXECON[TM] option; or
- injection of powdered sorbent between ESP fields (TOXECON-II[TM] approach).

Above powdered sorbent injection approaches might also be employed in combination with existing SO_2 control devices. For example, powdered sorbent might be injected prior to the SO_2 control device or after the SO_2 control device, subject to the availability of a means to collect the powdered sorbent downstream of the injection point.

In general, factors that appear to impact the performance of any particular sorbent include:

- injection concentration of the sorbent measured in lb/MMacf[b];
- flue gas conditions, including temperature and concentrations of HCl and sulfur trioxide (SO_3);
- the air pollution control configuration;
- the characteristics of the sorbent; and
- the method of injecting the sorbent.

These factors are discussed in more detail in the following sub-section.

Mercury Control by Conventional PAC Injection

The most widely tested sorbent for mercury control at utility boilers is PAC. Initial work focused on use of PAC because it is a material that is currently available for other uses (e.g., water treatment). PAC has been evaluated for mercury control in several pilot- and full-scale tests. More recently, field tests have been performed with other powdered sorbent materials such as enhanced PAC and silica-based sorbents, which are specifically formulated for controlling mercury emissions from power plants. As will be shown in the following sections, these specially-formulated sorbents appear to offer advantages over standard PAC in certain situations.

Numerous field tests have been undertaken to evaluate the use of powdered sorbent, especially PAC, on capture of mercury from power plants. These tests have been sponsored by the Department of Energy/National Energy Technology Laboratory (DOE/NETL), the Electric Power Research Institute (EPRI) and utility companies. Table 4 shows the test programs that

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[b] Sorbent injection rate is expressed in lb/MMacf, i.e., pounds of sorbent used for each million actual cubic feet of gas. For a 500 MW boiler, a sorbent rate of 1.0 lb/MMacf will correspond to approximately 120 lb/hour of sorbent.

have either evaluated, or are evaluating, standard PAC injection for mercury control. As shown in the table, the test programs cover a variety of configurations and fuel types.

Short-term PAC injection field tests
In the 2001-2003 time period, the Department of Energy/National Energy Technology Laboratory (DOE/NETL), the Electric Power Research Institute (EPRI) and a group of utility companies funded relatively short-term field test projects to evaluate the use of ACI as summarized in Table 5. The first four projects reflected in the table were DOE/NETL Phase I projects. Experience gained in these relatively short-term projects added to insights on factors, mentioned above, that appear to impact the mercury capture performance achieved via PAC injection. Some of this experience is described below.

Figure 8 shows the performance of a commonly used PAC product, Norit FGD, in full-scale parametric tests conducted in four of the projects.[22] Results in this figure reveal that, in general, injection of PAC at increasing amounts tends to increase mercury removal efficiency. However, in some cases, a limiting value of removal efficiency may be reached above which additional injected carbon will not provide additional mercury removal.

Temperature is known to impact the adsorption capacity of PAC, and therefore plays a very significant role. In most cases, the gas temperature at the available injection point upstream of the PM control device is around 300 °F and PAC has been shown to work effectively at this temperature. However, at temperatures approaching 350 °F or more, the effectiveness of standard PAC drops off rapidly.[23] This was verified in testing at Salem Harbor, where increasing the ESP inlet temperature from 300°F to 350°F reduced mercury removal from approximately 90 % to the 10-20 % range. Fortunately, cases where gas temperatures are this high are less common; such high temperatures, however, are found in lignite-fired boilers. Enhanced PACs or other sorbents may offer the capability to operate at much higher temperatures.

As shown in Figure 8, mercury removal close to 90% was achievable at injection rates approaching 20 lb/MMacf at Brayton Point 1. On the other hand, at Pleasant Prairie Power Plant (PPPP) #1 it was not possible to achieve greater than about 65% mercury removal regardless of the PAC injection rate. An important difference between these two CS-ESP sites was the amount of unburned carbon in the fly ash. The PPPP fly ash typically has very low levels of UBC in the fly ash (<1%) while the Brayton Point unit is equipped with low-NO_X burners and typically has higher levels of UBC in the fly ash. Another significant difference between these two sites was the relatively high level of chlorine in the coal used at Brayton Point (around 2000-4000 ppm) versus the relatively low chlorine level in the PPPP coal (around 8 ppm).[23] Moreover, the alkaline fly ash at PPPP was believed to have neutralized some of the HCl in the flue gas, thereby leaving relatively little chlorine available for mercury chemistry. The large difference in the amount of chlorine available in the flue gas for mercury chemistry is believed to contribute to the high level of Hg^{2+} at Brayton Point and the low level of Hg^{2+} at PPPP. Adequate chlorine in the gas stream is believed to be necessary for capture of Hg^0 by standard PAC. Because the mercury in the PPPP gas was almost entirely Hg^0, the low chlorine content limited the capture possible by the PAC. Nevertheless, test results showed that removal efficiency of Hg^0 and Hg^{2+} was about the same at PPPP.[23]

It is believed that acid gas components such as SO_3 compete with mercury for the active sites on PAC, and thereby can impact mercury capture performance of the PAC. In the tests conducted at Abbot, the best performance, 73% mercury capture, was achieved by injection of fine FGD at 13.8 lb/MMacf at an ESP inlet temperature of 341 °F. The high sulfur flue gas appeared to impair the performance of the PAC.

APC configuration can have a very significant impact on PAC performance. Gaston Unit 3 is a 270 MW bituminous coal fired boiler with a HS-ESP and a FF installed downstream of the air preheater in a COHPAC[TM] arrangement. The downstream FF in the COHPAC arrangement is smaller than a FF sized for the full ash loading. As shown in Figure 8, at Gaston, mercury removal rates around 90% attributable to the PAC were possible at injection rates less than 5 lb/MMacf. It is noted, however, that flue gas temperatures at COHPAC[TM] inlet, about 270 °F, were lower than those typically found at the inlet of PM controls at power plants. Such low temperatures may have enhanced capture of mercury in the carbon sorbent. Figure 8 also shows that the performance of PAC injection upstream of pilot FF when firing a subbituminous coal is similar to the performance demonstrated at Gaston.[23] The intimate contact between the PAC and the gas stream that occurs in a FF is believed to contribute to much higher removal than is possible through "in-flight" capture alone, such as for injection of PAC upstream of an ESP. Although there may be less chlorine present in the subbituminous coal, the high contact between the PAC and the gas in the FF facilitates the heterogeneous oxidation and adsorption of Hg^0 onto the PAC.

For all of the results shown in Figure 8, the sorbent used was a product called Norit FGD. In the case of PAC injection upstream of a CS-ESP, such as at PPPP and Brayton Point, the choice of sorbent made a significant difference in the performance. For example, at PPPP using treatment rates in the narrow range of 2.2 to 2.3 lb/MMacf the mercury removal ranged from 37% to 51% depending upon the sorbent selected. And, at Brayton Point for a treatment rate of 10 lb/MMacf the mercury removal ranged from 55% to 73%, depending upon the sorbent selected.[22] However, when the sorbent was captured in a FF, such as at Gaston, no significant difference in performance was observed between standard PAC sorbents (due to increased contact time, as discussed above). Therefore, it is likely that the PAC properties such as particle size make a significant difference in performance when most of the mercury capture is in-flight.

Speciated mercury capture data collected in the above projects is presented in Table 6. These data indicate that concentrations of Hg_p in flue gas at the outlet of PM controls were less than 0.35 µg/Nm^3 for conditions without and with sorbent injection. This simply indicates that PM controls were operating reasonably. With regard to gaseous mercury (both Hg^0 and Hg^{2+}), the following observations are made:

- Hg^0 concentrations at the outlet of PM controls were below 0.51 µg/Nm^3 under sorbent injection conditions at Salem Harbor and Gaston. However, the same was not the case at Pleasant Prairie, where such concentrations amounted to about 4.3 µg/Nm^3. This may be attributed to most of the mercury in the flue gas at Pleasant Prairie being Hg^0 and mercury removal efficiencies being about 70% in contrast to the much higher removal efficiencies achieved at Salem Harbor and Gaston.

- Hg^{2+} concentrations at the outlet of PM controls were below 1 µg/Nm^3 under sorbent injection conditions at all plants.
- ACI was quite efficient in decreasing Hg^{2+} concentrations in flue gas at PM control outlets as seen in results from Pleasant Prairie and Gaston. At Pleasant Prairie, without ACI, Hg^{2+} concentration at ESP exit was more than 6 µg/Nm^3, which was reduced to less than 0.5 µg/Nm^3 with ACI. Similarly, Hg^{2+} concentration at COHPAC exit was reduced from 10.4 µg/Nm^3 under no-ACI conditions to 0.8 µg/Nm^3 with ACI.

  Incidentally, at Pleasant Prairie, without ACI, Hg^0 concentration at ESP exit was more than 9 µg/Nm^3, which was reduced to less than 4.5 µg/Nm^3 with ACI; that is a reduction of approximately 50%. This reduction is lower than the greater than 90% reduction measured for a corresponding decrease in Hg^{2+} concentration.

The above observations indicate that ACI appears to be quite effective in controlling emissions of Hg $^{2+}$. However, this needs to be substantiated as more data is available.

Cremer et al. discuss the results of a program to evaluate a model for assessing the injection, mixing, and associated mass transfer effects of injecting sorbent into the gas stream for mercury capture.[24] In this program the PPPP PAC injection system was modeled using Computational Fluid Dynamic (CFD) software. Modeling suggested that mixing played a significant role in the in-flight mercury capture and, combined with test data, it suggested that some of the mercury removal was from PAC that had fallen out of the gas stream and deposited on surfaces. Modeling also suggested that only the smaller PAC particles (< 20 μm in diameter) were contributing significantly to mercury capture. Other programs to evaluate the importance of injection system design and particle size characteristics have also confirmed that these mass-transfer factors are significant in influencing performance of in-flight mercury capture by sorbent injection.[25] As a result, the factors that govern mass transfer of the sorbent must be well controlled for good performance. And, comparison of test results from different field test programs should consider if the mixing and distribution effects are comparable before drawing conclusions regarding the effects of other test conditions.

Longer term field test results with PAC injection[26]
Following the short-term testing at Gaston described above, some longer term tests were undertaken. The main objectives of these tests were to further evaluate the potential for the mercury capture performance seen in short-term tests and to test higher permeability FF bags with lower pressure drop. In full-load (270 MW) tests, PAC was injected nearly continuously in the period June 26-November 25, 2003, at rates less than 0.7 lb/MMacf to maintain acceptable FF cleaning frequency for FF operation at an air-to-cloth ratio of 8.0 ft/min. This resulted in weekly mercury removal between 80- 90%, with an average of 86%, for the test period as shown in Figure 9. To achieve 90% removal, additional lower load (195 MW), or lower throughput, tests were conducted with FF operating at an air-to-cloth ratio of 6.0 ft/min. In these tests, PAC was injected for 2 weeks in November 2003 and greater than 90% mercury removal was achieved at injection rates of 2 lb/MMacf or more. Subsequently, in December 2003 full-load (270 MW) tests were conducted with higher permeability bags[c] mounted in the FF, which

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[c] The higher permeability bags were 7.0 denier versus the original bags, which were 2.7 denier (denier is a measure of the linear density of a fiber and provides an indication of the cross section or thickness of the fibers). The

operated at a air-to-cloth ratio of 8.0 ft/min. Greater than 90% mercury removal was achieved at injection rates of 0.8 lb/MMacf or more with acceptable FF cleaning frequency. The results of these tests indicate that if the FF is designed properly to accommodate the carbon loading, 90% or greater removal of mercury with relatively modest PAC injection rates may be possible in a TOXECON[TM] arrangement.

Potential mercury capture constraints with PAC injection

In general, the efficacy of mercury capture in standard PAC increases with the amount of Hg^{2+} in flue gas[d], the number of active sites[e] in the PAC, and lower temperature. The amount of Hg^{2+} in flue gas is directly influenced by the amount of chlorine present in the flue gas. Based on these factors, standard PAC injection appears to be generally effective for mercury capture on low-sulfur bituminous coal applications, but less effective for the following applications:

- Low-rank coals + ESP with current capacity of greater than 150 GW and not expected to grow significantly in the future. Lower chlorine and higher calcium contents in coal lead to lower levels of chlorine in flue gas, which results in reduced oxidation of mercury and, therefore, lower Hg^{2+} in flue gas;
- Low-rank coals + SDA + FF with current capacity of greater than 10 GW and expected to grow significantly in the future. Similar effect as above, except lime reagent from the SDA scavenges even more chlorine from flue gas;
- High-sulfur coal, current capacity with wet FGD of approximately 100 GW and likely to grow to more than 150 by 2015. Relatively high levels of SO_3 compete for active sites on PAC, which reduces the number of sites available for mercury. Generally, plants will use wet FGD and, in many cases, SCR; PAC injection may be needed as a trim application; and
- Hot-side ESPs with capacity greater than 30 GW and not likely to grow. Weak (physical) bonds get ruptured at higher temperatures resulting in lower sorption capacity.

Mercury Control by Halogenated PAC Injection

Some situations, described above, may not have adequate chlorine present in the flue gas for good mercury capture by standard PAC. Accordingly, halogenated PAC sorbents have been developed to overcome some of the limitations associated with PAC injection for mercury control in power plant applications.[27, 28] Two different halogenated PAC sorbents have been tested in field tests. They are Sorbent Technologies Corp. brominated-PAC (B-PAC) and Norit America's halogenated PAC (E-3).

Halogenated PACs offer several potential benefits. Relative to standard PAC, halogenated PAC use: (1) may expand the usefulness of sorbent injection to many situations where standard PAC

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permeability of the bags was 130 cfm/ft^2 @ 0.5" H_2O versus the nominal 30 cfm/ft^2 @ 0.5"H_2O for the original bags.

[d] Standard PAC binds mercury via physical (i.e., weak) bonds, which are formed more easily with Hg^{2+}. There have been results that show a similar removal for both elemental and oxidized mercury. However, the results do not account for surface oxidation/sorption on the carbon.

[e] These are collection of atoms/radicals such as oxygen, chlorine, hydroxyls, which provide binding sites.

may not be as effective; (2) may avoid installation of downstream FF, thereby improving cost-effectiveness of mercury capture; (3) would, in general, be at lower injection rates, which potentially will lead to fewer plant impacts and a lower carbon content in the captured fly ash; (4) may result in somewhat better performance with low-sulfur (including low-rank) coals because of less competition from SO_3; and (5) may be a relatively inexpensive and attractive control technology option for developing countries as it does not involve the capital intensive FF installation.

As shown in Table 7, halogenated PACs have been tested at full-scale for many different combinations of coal type and PM controls. In each of these tests, relatively high levels of mercury removal were achieved with relatively modest injection rates when compared to results from tests with non-halogenated PAC injection in similar plant configurations.

Mercury control performance with halogenated PACs
Figure 10 shows comparative results from PPPP (full scale parametric data with PAC and pilot-scale data with B-PAC), St. Clair (full scale parametric test results with PAC and with B-PAC), and measured full-scale in-flight B-PAC mercury removal at Stanton 10 (S10), and parametric test data from Brayton Point.[22, 27] In all cases, injection was upstream of a CS-ESP or in-flight removal upstream of the FF was measured. Also, except for Brayton Point, in all cases the HCl content was expected to be very low due to the coal type (subbituminous in the case of PPPP and St. Clair, and lignite in the case of S10). As shown, PAC was unable to remove more than about 70% of the mercury at PPPP or St. Clair. In contrast, with B-PAC about 90% removal was achieved at around 5 lb/MMacf at both St. Clair and with the PPPP pilot. Also, for all cases where B-PAC was tested, similar results in terms of percent removal vs. injection rate were achieved. It should be noted that the ESP associated with B-PAC testing at St. Clair has a larger than typical SCA (700 ft^2/kacfm)[29] and this may potentially have contributed to high levels of mercury removal with modest B-PAC injection rates. On the other hand, since B-PAC injection rates were modest, they likely did not require a larger collection surface. As shown in Table 7, 70% mercury removal with a B-PAC injection rate of 4 lb/MMacf was obtained at the Lausche plant, which fires a high-sulfur bituminous coal and has a mid-sized ESP with SCA (370 ft^2/kacfm).[27] It is believed that mercury capture at Lausche was affected by the high sulfur content in coal; SO_3 in flue gas is believed to compete with mercury for active sites in the sorbent. At Cliffside (Low-sulfur bituminous coal with a hot side-ESP, and B-PAC), mercury reductions of 80% were measured at minimal load, and 40% at full load, during short term (2-weeks parametric) tests.[30] It is noted, however, that additional HS-ESP test programs with longer-term (30-day continuous) tests are planned/underway. These programs are summarized later in this document. Based on above observations, for boilers not firing high-sulfur coals and/or not using hot side-ESPs, injection of halogenated PAC, such as B-PAC, appears to have the potential to provide high levels of mercury removal under conditions that are challenging for PAC.

Figure 11 shows comparative test results from programs including PAC and B-PAC sorbents where a downstream FF was used. In these tests, B-PAC performance consistently was superior in terms of percent reduction for a given injection concentration. For the bituminous coal cases, the Valley pilot and the Gaston full-scale data correspond almost exactly. Similarly, the Stanton 10 and Valley pilot data correspond almost exactly, although Stanton 10 is a lignite-fired boiler

with SDA/FF and Valley is bituminous coal-fired. A comparison of the Stanton 10 data with PAC injection versus Stanton 10 data with B-PAC injection shows how dramatic the difference in performance can be.

Performance of a halogenated sorbent such as B-PAC appears to be relatively consistent regardless of coal type and appears to be mostly determined by whether or not the capture is in-flight (as in upstream of a CS-ESP) or on a fabric filter. This is shown in Figure 12 where B-PAC results from parametric tests are shown for in-flight and upstream of a fabric filter for various coal types. This is a significant development because performance of standard PAC is impacted by coal type as well as equipment.

Finally, available data shown in Figure 13 reflect that performance of B-PAC and E-3 for Western coal (PRB, lignite) is similar to that of TOXECON™ (using conventional PAC) for Eastern bituminous.

All of the data described above in this section are from shorter term parametric tests. The purpose of these tests was to determine conditions for longer-term testing with sorbents of interest. In these parametric tests, a sorbent was injected continuously for a few hours and mercury measurements were made. Subsequently, an operational parameter (usually the sorbent injection rate) was adjusted and the effect on mercury capture was measured. Each of the data points in Figures 10, 11 and 12 represents such a measurement. The results from these shorter term parametric tests were used to determine the condition s for longer-term tests, which are discussed below.

Longer term tests with halogenated PAC injection
As shown in Table 7, halogenated PACs have been tested for periods of 10 to 30 days at three plants. The results shown in Figures 14, 15, and 16 reflect relatively high levels of mercury removal were maintained for most of the testing periods with modest injection rates.

Speciated mercury capture data collected in the above projects is presented in Table 8. These data indicate that concentrations of Hg_p, Hg^0, and Hg^{2+} in flue gas at the outlet of PM controls were less than 0.6 μg/Nm^3 each with halogenated sorbent injection. Thus, in general, halogenated PAC injection appears to be quite effective in controlling emissions of each of Hg_p, Hg^0, and Hg^{2+}. Note, however, that data from Pleasant Prairie indicated that injection of standard PAC may be limited in controlling Hg^0.

Additional testing with halogenated PAC injection
A significant numbers of field tests are planned or ongoing over the next two years to further evaluate halogenated PACs for power plant applications. These are summarized below.

DOE Phase II Round 1 Projects
- B-PAC: 1-week parametric testing at Duke Energy, Cliffside 2, 40 MW, low-sulfur bituminous, HS-ESP; December 2004
- B-PAC: 30-day parametric and 30-day continuous testing at Duke Energy, Buck 5, 140 MW, low-sulfur bituminous, HS-ESP; Spring 2005

- Norit E-3: 30-day continuous testing at AEP Conesville 6, 500 MW, bituminous, ESP, wet FGD; June 2005
- Norit E-3: 30-day continuous testing at Detroit Edison Monroe 4, 375 MW, PRB/bituminous blend, ESP; November 2005

DOE Phase II Round 2 Projects (expected for 2006)
- B-PAC: 30-day parametric and 30-day continuous testing at Progress Energy, Lee 1, 80 MW, low-sulfur bituminous, ESP
- B-PAC: 2-week parametric testing at Progress Energy, Lee 2, 75 MW, low-sulfur bituminous, HS-ESP
- B-PAC: 30-day parametric and 30-day continuous testing at Midwest Generation, Crawford 7, 100 MW, subbituminous, ESP, sell ash for concrete
- B-PAC: 2-week parametric testing at Midwest Generation, Will County 3, 130 MW, subbituminous, HS-ESP, sell ash for concrete
- Norit E-3: Testing at TXU Big Brown Steam Electric Station, lignite-subbituminous blend
- Norit E-3: Testing at 2 facilities with TOXECON II™ configurations; one bituminous and one PRB; locations TBD

Other Advanced Sorbents and Additives

Aside from standard and halogenated PACs, other advanced sorbents and additives, designed to overcome shortcomings of PAC in certain power plant applications, are being developed and tested. These are briefly described below.

About 15% of the power plant fly ash in the United States, or about 10 million tons, is sold as a cement additive. PAC, when added to fly ash, however, adsorbs the Air Entraining Admixtures (AEA) that are used to provide the proper amount of fine air bubbles in concrete for good strength.[31] It is possible to segregate the fly ash from the PAC by the use of a TOXECON™ system. However, this entails significant capital expenditure and operating expense associated with the retrofit FF. An alternative is to modify the sorbents. Silica-based sorbents and specially-formulated PACs are under development to overcome some of the difficulties associated with use of PAC on facilities that sell their fly ash as a cement additive. Silica-based sorbents are being introduced by a company called Amended Silicates. These sorbents have not yet been tested for mercury removal at the full scale, but will be tested in 2005 at the Miami Fort unit 6, a 175 MW bituminous coal fired boiler with three small ESPs in series.[32, 33, 34] Specially-formulated B-PAC has been shown to avoid high foam index and offer similar mercury removal performance as B-PAC in a laboratory test facility.[31] However, additional development and testing of such specially-formulated sorbents is needed.

Sodium Tetrasulfide (STS) is a liquid chemical reagent that is injected into the gas stream in the same location as PAC. STS has been used on municipal waste combustors to remove mercury. It has the benefit of reacting to form a stable mercury compound (cinnabar) that can safely be added to concrete or disposed of. This technology has been tested for coal power plant use at the pilot scale.[35]

Efforts are underway to develop lower cost sorbents than commercial PAC sorbents. Sources include capture of devolatilized char from the furnace for use as a low-cost sorbent or oxidizing catalyst.[36] This carbon, known as the "Thief Process", was tested in a TOXECON^{TM} slipstream at the Pleasant Prairie Unit 1. The mercury reduction provided by the Thief carbon was not as high as for conventional PAC injected at the same rate, however, if the cost is significantly less it may justify the higher injection rate. Testing of several other low-cost sorbents such as corn char or treated fly ash, which may provide cost-effective benefits in some cases, has been undertaken.[37] These sorbents may be most useful in a TOXECON^{TM} arrangement, which will both segregate the sorbent from the ash and provide improved gas-sorbent contact so that even low capacity sorbents can provide good performance without impacting fly ash quality. Another possibility is to use a low-cost sorbent in combination with an additive to enhance sorbent capacity.

As discussed in the previous sections, chlorine plays an important role in facilitating the capture of Hg^0 on sorbent. For low-rank fuels in particular, there may not be adequate chlorine to achieve high Hg^0 capture efficiency with PAC. Use of halogenated PAC sorbents comprises one approach. Another is to inject a chemical into the fuel, or into the gas stream, to provide the halogens needed for high sorbent capacity. At the 220 MW Leland Olds plant firing lignite coal and equipped with CS-ESPs, a Sorbent Enhancement Additive (SEA) has been tested. SEA, a fuel additive, was added between the feeders and pulverizers. For the field tests, average baseline mercury removal was 18% and the objective was to determine the treatment regimen to reach 55% removal. A one month test with SEA and PAC showed that a 63% mercury removal rate was achieved over the period.[38] Therefore, as an alternative to more expensive sorbents, it may be possible to use standard PAC, or even less expensive sorbents, along with an additive, when such additives are broadly available.

Potential Plant Impacts Related to Sorbent Injection

Sometimes a technology may be very useful in reducing the pollutant required, but result in other adverse side effects that could significantly impact the plant reliability. The following are some issues that have been considered as possible concerns for sorbent injection.

Impact of PAC injection on downstream PM collector
Calculations reveal that the increase in PM loading to the ESP or FF due to PAC injection would be relatively modest (see Figure 17). For example, at a standard PAC injection rate of 10 lb/MMacf, with an ESP arrangement, about a 4% or less increase in total ash loading will be expected. For most applications, halogenated sorbents will likely be injected at rates less than 5 lb/MMacf and incremental PM loading in flue gas will be limited to about 2 percent. Thus, change in PM loading from PAC or halogenated PAC injection may be less than the loading change expected from routine fuel or fuel batch changes at a power plant. Consequently, concerns related to impact on ESP performance generally should not relate to increased mass loading with injection of these sorbents. In fact, in full-scale testing on large (SCA > 400) and small (SCA~140) ESPs, no adverse impact was shown on PM removal performance.[23, 39] Results from Brayton Point shown in Figure 18 reflect that ESP operation did not change with increase in PAC injection rate, even when this rate was as high as 20 lb/MMacf.[23]

Balance-of-plant impacts resulting from standard carbon injection are under investigation at Georgia Power's Yates Units 1 and 2, which are equipped with CS-ESPs with SCA's 173 and 144 ft^2/kacfm, respectively. During parametric ACI tests on these units, sorbent was injected at rates ranging from 2 lb/MMacf to greater than 12 lb/MMacf.[40] It was observed that at both units, ESP arc rates within all fields increased from 0 to 1 arcs/min to greater than 10 arcs/min. In some instances arc rates as high as 35 arcs/min were observed, but the arcing was very sporadic in nature.[41] Since arcing can degrade ESP PM capture performance, this was addressed in the subsequent one-month duration longer-term testing conducted on Unit 1 in the period mid-November through December 2004. Observations from longer-term tests are pending. In the longer-term testing, however, it was noted that sorbent injection rate greater than 4.5 lb/MMacf did not result in increased mercury removal, which ranged from 71-96% across the system.[42] Thus it appears to be unclear at this time if increased ESP arcing will occur at practical injection rates. Results from the longer-term testing at Yates Unit 1 should provide valuable information in this regard and this issue needs further investigation.

Measurements of PM concentrations at the outlets of ESPs at Yates Units 1 and 2, taken during parametric and longer-term testing, reflected that 70% of these measured concentrations were within, or less than, those measured during baseline testing. PM concentrations greater than baseline values were measured when sorbent injection rates were in excess of 4.5 lb/MMacf. It was observed that injection rates greater than 4.5 lb/MMacf did not appear to provide additional mercury removal beyond that obtained at 4.5 lb/MMacf. Thus, it is not clear if unacceptable excursions in ESP outlet PM concentration will take place at practical injections rates. It was also observed that the highest ESP outlet PM concentration (0.3 lb/MMBtu) occurred at a sorbent injection rate of 17 lb/MMacf.[42] Based on these observations, the potential for unacceptable PM emissions occurring due to sorbent injection at plants with small ESPs needs further investigation.

Yates Unit 1 is equipped with a Jet Bubbling Reactor FGD. During longer-term testing, samples of the scrubber slurry were taken periodically. During the period of 25 November through 10 December the scrubber slurry was observed to be either black or dark in color, while the carbon injection rate typically ranged from 4 - 6 lb/MMacf (with a few, brief periods at higher rates). Between November 25 and 29, the scrubber slurry was its darkest color, with its color slowly lightening over this time period. Prior to this time period, the scrubber slurry did not exhibit any visual evidence of carbon contamination. In the subsequent time period, the carbon injection rate was as high as 12 lb/MMacf, yet no further darkening was observed. Furthermore, while occasionally high PM concentrations were measured at the ESP outlet, no visible sign of carbon was noted on any of the particulate measurement train (Method 17) filters. From this limited set of data, it was observed that the breakthrough of carbon to the scrubber did not appear to be directly related to the magnitude of the carbon injection rate. Slurry samples will be analyzed to further evaluate this issue.[42]

TOXECON^{TM} results from Gaston have indicated, however, that retrofit FF will need to be sized properly to maintain acceptable FF pulsing frequency. Also, longer -term (24 days) halogenated carbon (E-3) injection tests on the SDA/FF system at Stanton Unit 10[43] revealed that the cleaning frequency of the FF increased to every 3 to 4 hours, as compared to 6 to 8 hours during baseline operation without sorbent injection. However, during sorbent injection tests, the slurry feed to

the SDA was varied to accommodate variations in coal sulfur content, which did not occur during the baseline testing. Since slurry feed rate can affect the frequency of FF cleaning, it was not possible to quantify the contribution of the sorbent injection to the changes in FF cleaning cycle. However, it was estimated that sorbent injection increased PM loading by a small amount, nominally 0.2% at an injection rate of 1 lb/MMacf and this small increase likely did not influence FF cleaning cycle. In addition to a change in cleaning frequency, a 4 - 6% increase in opacity was also observed for a very short time period (< 5 minutes) immediately after each FF cleaning step.

Potential for increase in fine PM emissions
Typically, the median of the particle size distribution for PAC or halogenated PAC sorbents is about 20 μm, and less than 5% of the sorbent particle mass is fine PM (i.e., less than 2.5 μm in size).[44] Calculations suggest that the increase in fine PM loading (i.e., fine PM mass added with sorbent injection relative to total PM mass in the flue gas) with sorbent injection rate of 10 lb/MMacf would be less than 0.2%. Further, fine PM removal efficiency of ESPs has been noted to be about 96%.[45] Accordingly, sorbent injection would be expected to increase direct fine PM emissions by less than 0.01%. These indications, however, need to be substantiated with measurements.

Fly ash sale for concrete manufacture
As discussed above, there is some concern about the impacts to marketing of fly ash for beneficial reuse, especially when the ash is used as a cement additive. This is more of a concern for units with ESPs where standard PAC treatment rate could be high enough to cause a problem with fly ash sales. But, it may also be a concern in some plants equipped with a FF. At this time there are a few technical approaches that may mitigate such concerns. One is segregating the fly ash with a TOXECON[TM] system. This, however, would entail higher capital costs. TOXECON-II[TM] may offer a lower cost approach, but it is under early testing. Finally, the last and the lowest capital cost approach – specially formulated sorbents - is under development as discussed above.

Adverse effects of PAC or additives on downstream equipment
So far, none of the test programs have shown any significant adverse impact to downstream equipment from the injection of PAC. Additives used to enhance PAC performance or other sorbents that may be used, however, might cause adverse effects on plant components. The potential for such impacts would have to be evaluated through long-term field testing conducted over time periods of several months or more.

Other Considerations Associated with Broad-Scale use of Sorbent Injection Systems

An assessment of the potential for broad-scale use of sorbent injection systems for mercury control has to take in to consideration retrofitting time frames that may be necessary to install the equipment and the availability of sorbents and associated hardware. These considerations are described below.

Retrofitting time frames and availability of hardware
A dry sorbent injection system is comprised of a storage silo, metering valves, blower and pneumatic material handling equipment, piping to the ductwork where injection occurs, and

associated control hardware. Injection ports are typically installed on low-pressure ductwork. All of this equipment is standard hardware that is readily available. EPA estimated that about 15 months would be needed from initial engineering review of technologies by the owner to completion of control technology testing for a PAC injection system without a retrofit FF.[46] The outage could be a week or so due to the minor changes to the ductwork that would be needed for the PAC injection system. Retrofitting a PAC injection system becomes more complicated if a TOXECON[TM] arrangement is chosen. In that case, about 26 months would be needed from initial engineering review of technologies by the owner to completion of control technology testing for the PAC injection system.

Since advanced sorbents will generally be injected at lower rates and specialized formulations, currently under development, may not adversely impact the value of the fly ash for beneficial reuse, there is a reduced likelihood that addition of a downstream FF or other PM control device modification will be needed. Therefore, retrofitting time frames for injection systems utilizing advanced sorbents should be the same as those for standard PAC systems without retrofit FF.

Availability of Sorbents
According to Norit, there is adequate excess capacity in the standard PAC market to absorb significant growth from current demand levels. However, if the regulations for mercury are passed, they would envision that plant(s) to supply this market would be built within 2-3 years.[47]

In general, halogenated PAC sorbents are made from standard PAC materials and halogens. Based on indications from vendors, supply of PACs may not be a constraint in manufacturing adequate amounts of halogenated PACs to provide significant reductions if this technology is used.

B-PAC is currently available from a facility capable of producing 1500 tons/year of sorbent. According to the vendor, production can be expanded in a six month period to meet market demand.[27]

Data/Science Gaps and Associated Recommendations

A number of chemical effects appear to be significant; however, they are not understood well enough to permit accurate prediction of sorbent performance under all circumstances, which may be desirable for design and selection of a sorbent injection system. Some of these effects include:

- The impact that chlorine, or HCl, has on sorbent capacity to adsorb Hg^0 is recognized but not understood in a quantitative way. This is a particular problem for coals with low chlorine levels that produce mercury mostly in the form of Hg^0.
- SO_3 is known to interfere with mercury capture. But, like chlorine, a quantitative understanding is lacking. This is important for high sulfur boilers or those with flue gas conditioning.
- Mercury concentration and speciation may influence the capture effectiveness of the sorbent. However, quantitative data on this effect is lacking.

Improved understanding of the chemical effects may be addressed through continued lab and pilot programs in parallel with the full-scale demonstration programs.

Mass transfer plays a critical role in influencing the effectiveness of a sorbent in capturing mercury, particularly for an application where mercury removal is largely in-flight. Some specific issues include:

- The role of sorbent physical characteristics. Reference 24 suggested that particle size distribution plays an important role.
- The relative importance of macro-scale (mixing of sorbent with the gas) versus micro-scale (diffusion at sorbent-gas interface) mass transfer processes under different conditions will guide sorbent injection system design.
- The extent to which performance can be improved by improvements in sorbent injection and distribution methods should be evaluated.

To improve understanding of mass-transfer effects, further development and validation of models, such as those described in Reference 24, should continue in combination with testing.

There are a significant number of boilers with HS-ESPs. Advanced sorbents may have the potential to dramatically reduce the control cost for these units that might otherwise need to add a downstream FF at high capital cost. Although HS-ESP test programs are planned, none of the demonstration programs appear to address HS-ESPs on low rank fuels. This data gap may need to be addressed, especially with advanced sorbents.

Efforts evaluating leaching of mercury and other metals from by products of PAC injection have generally shown that leaching of mercury does not appear to be a concern.[48, 49] The EPA's Office of Research and Development also has a program to evaluate the potential for leaching of metals from the management of mercury-enriched coal combustion residues (CCRs). To date, an evaluation of CCR's from five coal-fired power plants has been completed - three facilities with activated carbon injection (ACI) and two with scrubbers. This includes analysis and quantification of the leaching potential for mercury and non-mercury metals (arsenic and selenium). Results have also been completed to evaluate mercury leaching potential for 5 additional facilities representing 9 units.

The findings to date indicate that, for most management practices, leaching of mercury from fly ash does not appear to be of concern for land disposal of CCRs from facilities with activated carbon injection (for both regular PAC and brominated PAC). The limited results from scrubber sludge samples suggest that further evaluation is warranted. Leaching results for arsenic and selenium do suggest a potential concern and warrant further evaluation. Efforts are underway to obtain additional CCRs from a wider-range of coal types and air-pollution control configurations. In addition, better information on CCR management practices is being obtained to help clarify and document the fate and transport of mercury and other metals. This is an on-going research program within the EPA's ORD.

Some concern has been raised that the presence of brominated carbon may facilitate the formation of chlorinated and/or brominated organic air toxics (dioxins/furans) in the flue gas.

In October 2004, the Department of Energy (DOE) sponsored an approximately 30-day continuous B-PAC injection demonstration at Detroit Edison's St. Clair Power Plant. During this 30-day demonstration, an EPA-contracted sampling team collected flue gas samples from Unit #1, a 160 MW boiler that was burning PRB coal. For the measured chlorinated and brominated dioxins/furans, only one test (of three) showed a discernible difference in the amount measured as compared to that from the corresponding blank sample. All chlorinated and brominated dioxin/furans measured from the testing at DTE St. Clair were at least an order of magnitude lower than the limit of 60 ng/dscm for large municipal waste combustor (MWC) units with an ESP-based APCS (there are currently no limits for coal-fired utility boilers). For this reason, ORD does not expect there to be any significant increase in the emission of either the chlorinated or then brominated dioxins/furans from a coal-fired boiler with the addition of B-PAC or other similar brominated activated carbon upstream of a CS-ESP, assuming typical operating temperatures and conditions.

If dioxin/furan compounds were formed in the flue gas, it is likely that they may actually be captured by unburned carbon in the fly ash and/or on the injected PAC. Samples of the St. Clair fly ash were subjected to an organic extraction procedure to determine if there was enough brominated organic material to pursue a leaching test. The results were all in the single digit µg/g range. Based on this analysis, it was determined that any brominated compound that may leach from the fly ash would be at or below the analytical detection limit.

MERCURY CONTROL COSTS ASSOCIATED WITH SORBENT INJECTION

The cost of applying any technology is comprised of annualized capital costs, variable operating costs and fixed operating costs. The costs of a sorbent injection system are usually very small compared to other air pollution control equipment if addition of a PJFF or other major PM control device retrofit is not performed. According to Reference 50, capital costs for sorbent injection systems may be in the range of about $5/KW – sometimes less. Being simple pieces of equipment, the fixed operating costs for these systems are also relatively low. So, the major costs associated with a sorbent injection system are the cost of the sorbent and the disposal of additional material.

Figure 19 shows estimates of the cost of sorbent and disposal of sorbent for sorbent injection upstream of a CS-ESP. Estimates are made using halogenated PAC sorbent cost of $1.00/lb[f] and PAC sorbent cost of $0.50/lb; disposal is estimated at a cost of $25/ton. As shown in Figure 19, halogenated PAC is estimated to provide up to about 90% removal at a cost of sorbent and disposal under 1 mill/kWhr (1 mill/kWhr = $1.00/MWhr). Costs for standard PAC are estimated to be greater than those for halogenated PAC due to the significantly higher injection rate that is necessary. At a capital recovery factor of 13.3% and a capacity factor of 80%, levelized capital charge is approximately 0.1 mills/kWhr, which is significantly less than the variable operating cost associated with sorbent injection and disposal. A potential cost that is not included here is the cost of fly ash disposal in the event that fly ash is currently being sold for beneficial reuse but

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[f] Vendors claim that halogenated PACs cost about $0.75/lb today. However, considering the more developmental nature of these sorbents and the fact that these are aimed at a relatively narrow market, conservatively $1.0/lb was assumed in this analysis. It is recognized, however, that if these sorbents are available at $0.75/lb under future market conditions, costs associated with their use will only be less than indicated.

must be disposed of if contaminated with carbon. Since most plants do not currently sell their fly ash, this is not an incremental cost for them. However, for the minority of plants that sell their fly ash, the incremental costs are estimated to be in the range of 0.38 to 1 mill/kWhr, depending upon heating value and ash content of the coal and the heat rate of the unit and assuming a differential between fly ash revenues and disposal cost of $30/ton.[50]

Figure 20 shows the results of similar cost calculations for PAC injection upstream of a FF. The cost advantage of halogenated PAC over standard PAC when injected upstream of a FF is not expected to be as great as when injected upstream of a CS-ESP. Regardless of the sorbent, 90% removal appears to be possible at sorbent and disposal costs well below 0.50 mills/KWhr when this technology is available (see a discussion of the outlook for technology availability in a subsequent section). For facilities that sell their fly ash for concrete, if the fly ash is rendered unmarketable, the differential cost to dispose of the fly ash is similar to that described above for CS-ESP.

EXPECTED RESULTS IN NEXT TWO YEARS

The ongoing research activities into control of mercury are proceeding at a rapid pace. Much has been learned in the last year, and more progress is anticipated over the next two years. There are several test programs planned over the next year that will explore:

- Mercury capture by FGD and the impact of SCR on FGD capture.
- Use of advanced sorbents in difficult configurations, such as HS-ESP, and sorbents that are formulated to work with concrete additives when ash is disposed.
- Start up of the first commercial full-scale TOXECON^{TM} system designed expressly to accommodate sorbent addition.
- Testing of advanced sorbents at units with HS-ESPs without a downstream FF.
- Methods to enhance capture of mercury by existing equipment by fuel additives, oxidizing chemicals, or oxidation catalysts upstream of FGD.
- Methods to enhance capture of mercury by standard PAC or low cost sorbents using fuel additives, oxidizing chemicals, or oxidation catalysts upstream of FGD.
- Further evaluation of the fate of mercury in wall-board produced from FGD by-product to assure that it does not become volatilized and released.

Data available from above testing should help in advancing the development of a broad suite of viable mercury control approaches.

OUTLOOK FOR TECHNOLOGY AVAILABILITY

In order to examine the status of technology and the factors affecting its availability, Table 9 summarizes the available information to reflect potentially viable mercury control approaches for various boiler configuration and coal type combinations. As can be appreciated from the information included in the table, technology availability will: (1) vary by boiler configuration and coal type; (2) depend on available data (direct and relevant) with much more data expected in the next 2 years; and (3) depend on regulatory framework, i.e., a spectrum from minimum risk to technology forcing. The principle concerns relating to broad-scale use of mercury controls are

the reliability of mercury reductions possible and the risks of adverse side effects. To the extent that required mercury reductions are within the capabilities of the technology with minimum risks of side effects, mercury controls could be considered available. However, as discussed in this paper, there remain some questions regarding their performance relative to broad-scale use. These questions are being investigated in ongoing efforts.

In the February 2004 ORD White Paper, it was projected that PAC injection technology would be available after 2010 for commercial application on all key combinations of coal type and control technology and that mercury removal levels in the 70% to 90% range could be achievable. In the same white paper, it was projected that enhanced multipollutant control systems (PM controls + dry FGD, PM controls + wet FGD, or SCR + PM controls + dry or wet FGD) would be available after 2010 to provide removal levels between 60 and 90 %. Finally, the February 2004 White Paper also projected that optimized multipollutant control would be able to provide 90-95% mercury removal for all coals after 2015. These projections assumed the funding and successful implementation of an aggressive, comprehensive RD&D program.

As discussed in this document, since the release of the earlier White Paper, additional data, mostly from short-term tests, have become available on mercury control approaches for power plants. Also, a broad and aggressive RD&D program is underway, which will yield experience and data in the next few years. Accordingly, ORD continues to believe that PAC injection and enhanced multipollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. However, considering the progress made with halogenated PAC sorbents and other chemical injection approaches, it is now believed that optimized multipollutant controls may be available in the 2010-2015 timeframe for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 90 and 95%. Such optimized controls could include less expensive use of sorbent (PAC or halogenated PAC) injection with enhanced SCR and/or enhanced FGD systems.

A national retrofit program can be initiated after the technology is available. However, full implementation of such a retrofit program would take a number of years to accomplish and achieve emission reductions, since large numbers of utilities would need time to order, design, fabricate and test such units. Based on EPA experience with coal-fired utility boiler retrofit technologies, we estimate that once a utility has signed a contract with a vendor, installation on a single boiler could be accomplished in the following timeframes:

- Sorbent injection upstream of an existing ESP or FF could be installed with commissioning complete in six months to 1 year;
- Sorbent injection upstream of a retrofit fabric filter (e.g., COHPAC) could be retrofitted to an existing ESP in under 2 years;
- A new SCR/FGD/PM/mercury control system could be retrofitted in 2-3 years dependent on the retrofit difficulty[g]; and,

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[g] It is important to note that due to the high capital cost of SCR and FGD, these technologies are not expected to be installed solely on the basis of mercury removal, but primarily on the basis of controlling other pollutants, because much less costly mercury removal methods are available.

- Existing SCR or FGD to enhance mercury control could be retrofitted in about one to two years.

The installation timeframes described above include the time periods associated with control technology fabrication, delivery, construction, and testing; approval of construction permit; and modification of operating permit.

SUMMARY

Although the potential mercury emissions from coal-fired U.S. utility boilers are calculated to be 75 tons per year based on the mercury content in coal, the actual current emissions are estimated to be 48 tons per year due to mercury capture with pollution controls for PM and SO_2. NOx controls can augment mercury capture in PM and SO_2 control equipment. And, with increased use of NOx and SO_2 pollution controls in the coming years as shown in Table 2, the co-benefit removal of mercury from these controls is expected to be significantly increased. Furthermore, it may be possible to operate these pollution controls in a way to improve mercury capture without sacrificing control of other pollutants. RD&D efforts aimed at enhancing mercury removal of existing controls in the next year should provide information on strategies to maximize mercury co-benefits.

RD&D activities relating to sorbent injection for mercury removal over the last year have shown significant advances in this technology. Although most test programs have taken place over a few days, some have run for several weeks, and one has run for 6 months. These longer term tests have confirmed the performance of short term tests, and have also provided insights related to operating concerns expressed by plant personnel. At this time no serious adverse effects on the plant have been found with sorbent injection for tests up to one month in duration. Moreover, control approaches have been tested at the full scale and pilot scale under conditions that were previously shown to be difficult for standard PAC. These approaches, involving advanced sorbents, fuel blending, and fuel additives, appear to provide effective and less expensive means to address some of the mercury control difficulty previously identified with low rank coals. Halogenated PAC sorbents have shown particularly impressive results; they have been tested on a number of different facilities over a range of fuels and appear to capture mercury effectively for a given configuration regardless of fuel type. Also, no balance-of-plant impacts have been reported in field tests conducted thus far.

Some key observations are as follows:

1. Projections reflect that current and future NO_X and SO_2 emission reduction requirements are expected to result in growing use of SCR and scrubber systems at coal-fired utility boilers. Ongoing RD&D has the potential to provide the basis for enhanced mercury removal in such systems. Assuming sufficient RD&D of representative technologies, new and existing systems installed to control NO_X and SO_2 (e.g., SCR+FGD+FF) have the potential to achieve 90+% control of mercury on bituminous coal-fired boilers. Subbituminous and lignite systems appear to require mercury oxidation technology and/or additional advanced sorbents to achieve these levels.

2. While co-benefit mercury removal from the flue gas of boilers firing low rank coals is generally lower than for bituminous coal, methods to improve co-benefit removal – such as fuel blending and fuel additives - have shown great promise. If successful, these approaches will narrow the difference between the various coals.

3. While it is more difficult to remove mercury from the flue gas of boilers firing low rank coals with standard PAC injection, new halogenated sorbents appear to offer a very effective and less expensive alternative that can deliver higher removals than possible with standard PAC alone. However, longer-term demonstrations will be beneficial in that they will provide additional experience and data, which will build confidence in use of these new sorbents.

4. Development and testing of new sorbents or additives has proceeded at a very rapid pace, and will likely continue to do so. Sorbent injection systems can be installed quickly and new sorbents or furnace additives can be tested relatively easily. This is in contrast to more capital intensive technologies like SCR or FGD, which require a long time to engineer and install the equipment or to make any significant changes to it, such as a catalyst change. Therefore, it is anticipated that the rapid pace of technology development for new sorbents and chemical additives will continue.

5. There is increased appreciation for the importance of mass transfer in the sorbent capture process. Therefore, there is likely to be some improvement in performance due to improved injection methods, especially for in-flight removal. Such enhancements have the potential to improve performance for both standard and new sorbents.

6. Halogenated PAC injection with a CS-ESP has the potential to achieve 90% mercury control. Standard PAC injection with an ESP (HS or CS) and a retrofit fabric filter, or a fabric filter alone, has the potential to achieve over 90% mercury reduction. Proper design and consideration of operational and residue impacts would need to be incorporated.

7. The one application that remains particularly challenging is units with HS-ESP. This represents about 12% of current coal-fired capacity. Currently, retrofit of a downstream FF after the air preheater and sorbent injection prior to the FF is the only approach that has proven to be effective for these units at all load conditions. New sorbents have been tested for achieving mercury removal upstream of a HS-ESP. Promising results were achieved with these sorbents at part load conditions. With focused RD&D perhaps these sorbents can be improved to be effective at all load conditions.

8. Cost estimates will vary depending upon specific conditions including regulatory structure. Nevertheless, for most units, it is projected that the mercury removal would add no more than about 2 mills/kWh to the annualized cost of power production. For many applications utilizing halogenated PAC sorbents, costs are projected to be generally lower than 1 mill/kWh. For the minority of plants that sell their fly ash and this sale is impacted due to mercury control, the incremental costs, associated with waste disposal and lost revenue due to impact on fly ash sale, are estimated to be in the range of 0.38 to 1 mill/kWhr. Control by enhancing/optimizing cobenefit mercury removal in FGD and SCR systems has the potential to reduce costs substantially, since optimized systems may require little additional investment and/or operational costs, especially for bituminous coals.

9. It is believed that PAC injection and enhanced multipollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. Also optimized multipollutant controls may be available in the 2010-2015 timeframe for commercial application on most, if not all, key combinations of coal type and control technology to

provide mercury removal levels between 90 and 95%. Such optimized controls could include less expensive use of sorbent (PAC or halogenated PAC) injection with enhanced SCR and/or enhanced FGD systems. It is noted, however, that broad scale commercial application of control technology to remove mercury will be possible after the technology is available. Therefore, initiation of a potential national retrofit program could take place after the technology is available and such a program would take a number of years to fully implement.

Based on EPA experience with coal-fired utility boiler retrofit technologies, we estimate that once a utility has signed a contract with a vendor, installation on a single boiler could be accomplished in the following timeframes:

- Sorbent injection upstream of an existing ESP or FF could be installed with commissioning complete in six months to 1 year;
- Sorbent injection upstream of a retrofit fabric filter (e.g., COHPAC) could be retrofitted to an existing ESP in under 2 years;
- A new SCR/FGD/PM/mercury control system could be retrofitted in 2-3 years dependent on the retrofit difficulty; and,
- Existing SCR or FGD to enhance mercury control could be retrofitted in about one to two years.

The installation timeframes described above include the time periods associated with control technology fabrication, delivery, construction, and testing; approval of construction permit; and modification of operating permit.

Table 1. General Characteristics of Coals Burned in U. S. Power Plants

Coal	Mercury ppm (dry)		Chlorine ppm (dry)		Sulfur % (dry)		Ash % (dry)		HHV* BTU/lb (dry)	
	Range	Avg	Range	Avg	Range	Avg	Range	Avg	Range	Avg
Bit	0.036 - 0.279	0.113	48 - 2730	1033	0.55 - 4.10	1.69	5.4 - 27.3	11.1	8646 - 14014	13203
Subbit.	0.025 - 0.136	0.071	51 - 1143	158	0.22 - 1.16	0.50	4.7 - 26.7	8.0	8606 - 13168	12005
Lignite	0.080 - 0.127	0.107	133 - 233	188	0.8 - 1.42	1.30	12.2 - 24.6	19.4	9487 - 10702	10028

* Higher Heating Value

Table 2. Projected Coal-Fired Capacity by APC Configuration

APC Configuration	Current Capacity, MW	2010 Capacity, MW	2020 Capacity, MW
Cold-side ESP	111,616	75,732	48,915
Cold-side ESP + Wet Scrubber	41,745	34,570	33,117
Cold-side ESP + Wet Scrubber + ACI	-	379	379
Cold-side ESP + Dry Scrubber	2,515	3,161	5,403
Cold-side ESP + SCR	45,984	35,312	22,528
Cold-side ESP + SCR + Wet Scrubber	27,775	62,663	98,138
Cold-side ESP + SCR + Dry Scrubber	-	11,979	13,153
Cold-side ESP + SNCR	7,019	4,576	2,534
Cold-side ESP + SNCR + Wet Scrubber	317	2,830	6,088
Fabric Filter	11,969	10,885	7,646
Fabric Filter + Dry Scrubber	8,832	8,037	9,163
Fabric Filter + Wet Scrubber	4,960	4,960	4,960
Fabric Filter + Dry Scrubber + ACI	-	195	195
Fabric Filter + SCR	2,210	2,950	1,330
Fabric Filter + SCR + Dry Scrubber	2,002	2,601	4,422
Fabric Filter + SCR + Wet Scrubber	805	805	2,363
Fabric Filter + SNCR	267	267	345
Fabric Filter + SNCR + Dry Scrubber	559	557	557
Fabric Filter + SNCR + Wet Scrubber	932	932	1,108
Hot-side ESP	18,929	11,763	10,160
Hot-side ESP + Wet Scrubber	8,724	10,509	10,398
Hot-side ESP + Dry Scrubber	-	538	538
Hot-side ESP + SCR	5,952	3,233	1,847
Hot-side ESP + SCR + Wet Scrubber	688	6,864	9,912
Hot-side ESP + SNCR	684	1,490	1,334
Hot-side ESP + SNCR + Wet Scrubber	474	474	627
Total Existing Units	**304,955**	**298,263**	**297,161**
New Builds of Coal Steam Units	**Current Capacity, MW**	**2010 Capacity, MW**	**2020 Capacity, MW**
Fabric Filter + SCR + Wet Scrubber	-	221	17,292
Total All Units	**304,955**	**298,484**	**314,453**
Note: IGCC units are not included as part of this list.			
Note: Current capacity includes some SCR and FGD projected to be built in 2005 and 2006			
Note: 2010 and 2020 is capacity projected for final CAIR rule			
Note: IPM projects some coal retirements and new coal in 2010 and 2020			

Table 3. Scrubber testing with SCR and/or additive to reduce re-emission of Hg^0 and improve mercury capture.

Test Site Information			Mercury Capture Across Scrubber, %			Test/Observation
Test Site	**Coal**	**Controls**	**Elemental**	**Oxidized**	**Total**	
Dominion Resources Mount Storm Power Station Unit 2, 563 MW	Medium-sulfur Eastern bituminous	SCR, Cold-side ESP, limestone forced oxidation FGD	-15%	> 90%	71%	4-day; SCR by-passed; no additive/Hg(0) re-emission
			30%	> 90%	78%	4-day; SCR by-passed; with additive/no re-emission of Hg(0)
			0	> 95%	> 90%	6-day; SCR on-line; no additive/no re-emission of Hg(0) and higher Hg removal
			0	> 95%	> 90%	7-day; SCR on-line; with additive/no re-emission of Hg(0) and higher Hg removal; no effect from additive

Table 4. PAC test programs on power plant flue gases.

APC Configuration	Coal Type		
	Bituminous	**Subbituminous**	**Lignite**
CS-ESP	Hudson[p] Brayton Point 1 Salem Harbor 1 Yates 1, 2 Valley[p] Lausche *Miami Fort* *Allen* *Conesville*	Pleasant Prairie 1 Powerton[p] (TOXECON) St. Clair 1 Meramec Miller[p] *Nantikoke*	Leland Olds 1 Coal Creek *Stanton 1* *Poplar River 1, 2*
HS-ESP	Gaston 3 (TOXECON) Cliffside	none	none
FF	none	Comanche 2[p] Pleasant Prairie 1, 2[p] TOXECON *Presque Isle 7-9* *TOXECON*	Spruce
SDA-FF	none	Holcomb	Stanton 10 *Antelope Valley 1*
PS	none	Laskin 2	none
p: denotes pilot test *Italic* denotes program not yet completed			

Table 5. Relatively short-term PAC injection field test projects.

Test Site Information			Mercury Capture, %		
Test Site	**Coal**	**Particulate Control**	**Baseline**	**ACI Test Results**	**"Long-term" Test Duration***
PG&E NEG Brayton Point, Unit 1	Low-sulfur Bituminous	Two CS-ESPs in Series	90.8	94.5	ACI for two 5-day periods
PG&E NEG Salem Harbor, Unit 1	Low-sulfur Bituminous	CS-ESP	90	94	ACI for one 4-day period
Wisconsin Electric Pleasant Prairie, Unit 2	Subbituminous	CS-ESP	5	65	ACI for one 5-day period
Alabama Power Gaston, Unit 3	Low-sulfur Bituminous	HS-ESP + COHPAC	0	25-90	ACI for one 9-day period
University of Illinois Abbott Station	High-sulfur Bituminous	CS-ESP	0	73	

* At these plants, both short-term parametric and "long-term" continuous tests were conducted. In each of these tests the "long-term" testing lasted less than 10 days.

Table 6. Speciated mercury results from ACI field tests.

	Particulate (μg/dNm^3)	Elemental (μg/dNm^3)	Oxidized (μg/dNm^3)	Total (μg/dNm^3)
Pleasant Prairie (Baseline)				
ESP Inlet	1.97	12.22	2.51	16.71
ESP Outlet	0.01	9.8	6.01	15.82
Removal Efficiency (%)	99.49	19.8	*	5.27
Pleasant Prairie (ACI, 11 lbs/MMacf)				
ESP Inlet	1	14.7	1.7	17.4
ESP Outlet	0	4.3	0.4	4.7
Removal Efficiency (%)	100	70.75	76.47	**72.99**
Salem Harbor (Baseline)				
ESP Inlet	10.15	< 0.27	0.09	< 10.51
ESP Outlet	< 0.34	< 0.50	0.41	< 1.25
Removal Efficiency (%)	> 96	*	*	≅ 88
Salem Harbor (ACI, 10 lbs/MMacf)				
ESP Inlet	4.9	< 0.27	0.07	< 5.24
ESP Outlet	< 0.09	< 0.51	0.02	< 0.62
Removal Efficiency (%)	> 98	*	71.43	**≅ 88**
Gaston (Baseline)				
COHPAC Inlet	0.1	5.5	8.8	14.4
COHPAC Outlet	0	3.1	10.4	13.5
Removal Efficiency (%)	100	43.64	*	6.25
Gaston (ACI injection, 1.5 lbs/MMacf)				
COHPAC Inlet	0.2	4.2	5.9	10.3
COHPAC Outlet	0.1	< 0.1	0.8	1
Removal Efficiency (%)	50	> 97	86.44	**90.29**

* Efficiency calculation not appropriate because outlet value is greater than inlet value.

Table 7. Full-scale halogenated PAC testing.

Coal Type	PM Control	Hg Removal (%)	Sorbent	Injection Rate (lb/Mmacf)	Plant	Testing Period	Duration
Sub-bit Blend	CS ESP	94	B-PAC	3.0	St. Clair	Oct-04	30 day continuous
Sub-bit Blend	SD/FF	93	E-3	1.2	Holcomb	Jun-04	30 day continuous
Sub-bit	CS ESP	80-90+	E-3	4.0 - 4.5	Meramec	Oct-04	10 day continuous
Bit High-S	CS ESP	70	B-PAC	4.0	Lausche	Jan-03	2 - 3 hr tests
Bit Low-S	HS ESP	>80	B-PAC	6.4	Cliffside (minimum load)	Sep-03	2 wks parametric
		40	B-PAC	5.7	Cliffside (full load)	do	do
Lignite	SD/FF	95	B-PAC	1.5	Stanton 10	early 2004	2 hr parametric
Lignite	*	70	B-PAC	1.5	Stanton 10	early 2004	2 hr parametric
Lignite	SD/FF	95	E-3	1.5	Stanton 10	early 2004	2 hr parametric

Table 8. Speciated mercury results from halogenated PAC injection field tests.

	Particulate ($\mu g/dNm^3$)	Elemental ($\mu g/dNm^3$)	Oxidized ($\mu g/dNm^3$)	Total ($\mu g/dNm^3$)
Meramac (Baseline)				
ESP Inlet	3.54	9.03	2.2	14.77
ESP Outlet	0	6.57	2.73	9.3
Removal Efficiency (%)	100	27.2	*	37.03
Meramac (E-3 injection, 3 lbs/MMacf)				
ESP Inlet	3.2	3.8	3.1	10.1
ESP Outlet	0	0.4	0.2	0.6
Removal Efficiency (%)	99.9	89.47	93.55	**94.06**
Holcomb (Baseline)				
Inlet	0.47	7.71	2.38	10.56
Outlet	0.01	10.75	0.47	11.23
Removal Efficiency (%)	97.87	*	80.25	*
Holcomb (E-3 injection, 1.2 lbs/MMacf)				
Inlet	0.01	8.49	0.9	9.4
Outlet	0	0.39	0.1	0.49
Removal Efficiency (%)	100	95.4	88.89	**94.8**
St. Clair (Baseline)				
ESP Inlet	0.11	7.18	0.61	7.9
ESP Outlet	< 0.01	6.99	4.24	11.23
Removal Efficiency (%)	> 90.9	2.65	*	*
St. Clair (B-PAC injection, 3 lbs/MMacf)				
ESP Inlet	0.26	7.11	0.97	8.08
ESP Outlet	< 0.1	0.38	0.55	0.93
Removal Efficiency (%)	> 61	94.66	43.3	**87.65**

*Efficiency calculation not appropriate because outlet value is greater than inlet value.

Table 9. Potentially most-suitable mercury control approaches for various boiler configuration and coal type combinations.

Coal/Technology, (Capacity, %)[h]	Incremental Mercury Control	Direct Experience[i]	Relevant Experience[j]	Remaining Issues	Ongoing Efforts
Subbit + CS-ESP – w/ or w/o SCR (~66 GW, 22.3%)	Hal-PAC	> 90% St. Clair (80 MW tested); 80-90% Meramec (70 MW tested)	None	a) Direct experience with longer-term testing; testing with larger duct sizes; air toxics; ESP impacts, residue impacts; long-term corrosion; sorbent supply.	DOE Phase II Round 1: 30-day testing with E-3 at DTE Monroe 4 (375 MW), November 2005 DOE Phase II Round 2: 30-day continuous testing with B-PAC at Midwest Gen Crawford 7 (100 MW), TBD DOE Phase II Round 2: testing with Alstom's enhanced sorbent at PacificCorp. Dave Johnston plant, TBD
Low-S bit + CS-ESP – w/ or w/o SCR (~ 55 GW, 18.6%)	Hal-PAC	**None**	> 90% St. Clair (80 MW tested); 80-90% Meramec (70 MW tested)	Same as a)	DOE Phase II Round 2: 30-day continuous testing with B-PAC at Progress E. Lee 1 (80 MW), TBD DOE Phase II Round 2: testing with Alstom's enhanced sorbent at Reliant En. Portland unit, TBD

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[h] These numbers were generated using the following approach: (1) current capacity numbers are from information in Table 2; (2) breakdown of coal production was taken from DOE Energy Information Administration, Annual Coal Report 2003, Table 6, available at (http://www.eia.doe.gov/cneaf/coal/page/acr/table6.html). This reflected production of bituminous, subbituminous, and lignite in 2003 of 51.5%, 41.3%, and 7.7%, respectively; (3) coal production pattern was considered to be similar to usage in electric utilities; (4) coal usage pattern was approximated to 50% bituminous, 40% subbituminous, 5% ND lignite, and 5% TX lignite; and (5) 1/3 of bituminous coal consumed in power plants was considered to be high-sulfur and the remaining 2/3 was assumed to be low-sulfur.

[i] *Direct experience* is where experience is available with the *exact* combination of coal type, existing control technology, and mercury technology.

[j] *Relevant experience* is where applicable experience appears to be available even though not with the *exact* combination of coal type, existing control technology, and mercury technology.

Table 9. Potentially most-suitable mercury control approaches for various boiler configuration and coal type combinations; (continued).

Coal/Technology, (Capacity, %)	Incremental Mercury Control	Direct Experience	Relevant Experience	Remaining Issues	Ongoing Efforts
Hi-S bit + CS-ESP + wet FGD (~42 GW, 14.2%)	Hal-PAC	**None**	70% Lausche (18 MW tested)	Same as a) + impact on FGD	DOE Phase II Round 1: 30-day testing with E-3 at AEP Conesville (500 MW), June 2005
Coal + HS-ESP (~35 GW, 12.0%)	TOXECON; possibly Hal-PAC	>90% Gaston (135 MW tested)	None	b) Direct experience with longer-term testing; FF impacts, residue impacts; sorbent supply.	DOE Phase II Round 1: 30-day continuous testing with **B-PAC** at Duke En. Buck 5 (140 MW), low-S bit., spring 2005 DOE Phase II Round 2: 2-week parametric test with **B-PAC** at Progress En. Lee 2 (75 MW), low-S bit., TBD DOE Phase II Round 2: 2-week parametric test with **B-PAC** at Midwest Gen Will County 3 (130 MW), TBD
Hi-S bit + CS-ESP + SCR + wet FGD (~28 GW, 9.4%)	Hal-PAC (trim), if needed. SCR + FGD should provide high removal.	**None**	>80% various data on wet FGD + SCR; 70% Lausche (18 MW tested)	Same as a) + impact on FGD	

Table 9. Potentially most-suitable mercury control approaches for various boiler configuration and coal type combinations; (continued).

Coal/Technology, (Capacity, %)	Incremental Mercury Control	Direct Experience	Relevant Experience	Remaining Issues	Ongoing Efforts
Hi-S bit + CS-ESP – w/ or w/o SCR (~27 GW, 9.3%)	TOXECON	None (coal effects less significant with FF)	ICR data and > 90% Gaston (135 MW tested)	Same as b)	
ND Lignite + CS-ESP – w/ or w/o SCR (~8 GW, 2.8%)	Hal-PAC	**None**	> 90% St. Clair (80 MW tested); 80-90% Meramec (70 MW tested)	Same as a)	DOE Phase II Round 2: testing with Alstom's enhanced sorbent at Basin Electric Leyland Olds, TBD
TX Lignite + CS-ESP – w/ or w/o SCR (~8 GW, 2.8%)	Hal-PAC	**None**	> 90% St. Clair (80 MW tested); 80-90% Meramec (70 MW tested)	Same as a)	DOE Phase II Round 2: 30-day testing with PAC and advanced sorbent (TBD) at TXU Big Brown (300 MW), TOXECON configuration, TBD
Low-S bit + FF – w/ or w/o SCR (~ 7 GW, 2.4%)	PAC	None (high intrinsic removal expected)	ICR data and > 90% Gaston (135 MW tested)	Same as b)	
Subbit + FF – w/ or w/o SCR (~6 GW, 2.0%)	PAC	Comanche 2 pilot (600 acfm tested) - >90% possible. Good performance expected with FF.	ICR data; > 90% Gaston (135 MW tested)	Same as b)	

Table 9. Potentially most-suitable mercury control approaches for various boiler configuration and coal type combinations; (continued).

Coal/Technology, (Capacity, %)	Incremental Mercury Control	Direct Experience	Relevant Experience	Remaining Issues	Ongoing Efforts
Medium-S bit + SD+FF – w/ or w/o SCR (~6 GW, 1.9%)	PAC (trim), if needed	None (high intrinsic removal expected)	ICR data and > 90% Gaston (135 MW tested)	Same as b)	
Subbit + SD+FF – w/ or w/o SCR (~5 GW, 1.5%)	Hal-PAC	> 90% Holcomb (360 MW tested)	None	Same as a); duct size may not be an issue for FF applications	
ND Lignite + FF – w/ or w/o SCR (~0.7 GW, 0.2%)	PAC	None. Good performance expected with FF.	Comanche 2 pilot (600 acfm) - >90% possible ICR data; > 90% Gaston (135 MW tested)	Same as b)	
ND Lignite + SD+FF – w/ or w/o SCR (~0.5 GW, 0.2%)	Hal-PAC	> 90% Stanton 10 (60 MW tested)	None	Same as a); duct size may not be an issue for FF applications	
TX Lignite + FF – w/ or w/o SCR (~0.7 GW, 0.2%)	PAC	None. Good performance expected with FF.	Comanche 2 pilot (600 acfm tested) - >90% possible ICR data; > 90% Gaston (135 MW tested)	Same as b)	
TX Lignite + SD+FF – w/ or w/o SCR (~0.5 GW, 0.2%)	Hal-PAC	None. Good performance expected with FF.	> 90% Stanton 10 (60 MW tested)	Same as a); duct size may not be an issue for FF applications	

Figure 1. Projected coal-fired capacity with FGD

- CAIR Retrofits
- Existing or CAA Title IV/State Retrofit
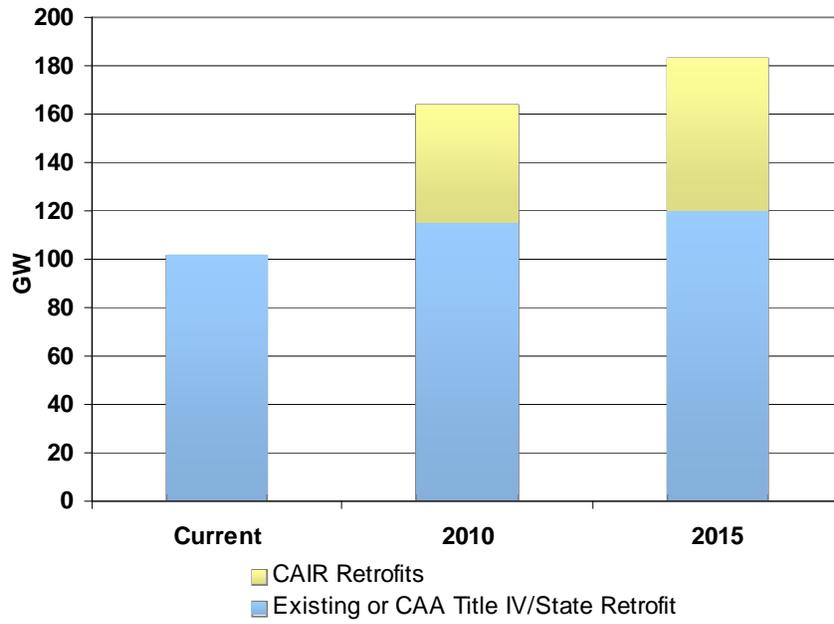
Figure 2. Projected coal-fired capacity with SCR

- CAIR Retrofits
- Existing or NOx SIP Call/State Retrofit
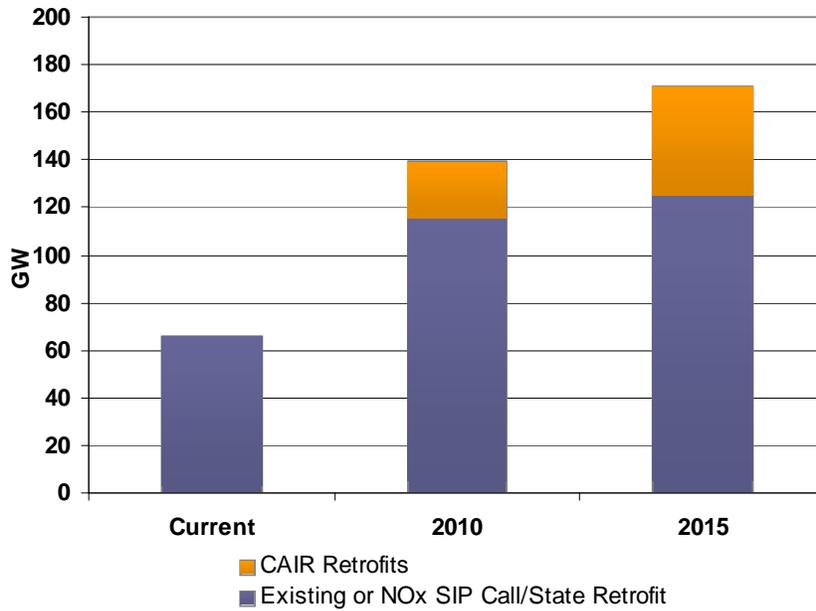
Figure 3. Mercury removal rates measured for various coal types and air pollution control configurations (from EPA ICR data, 1999).
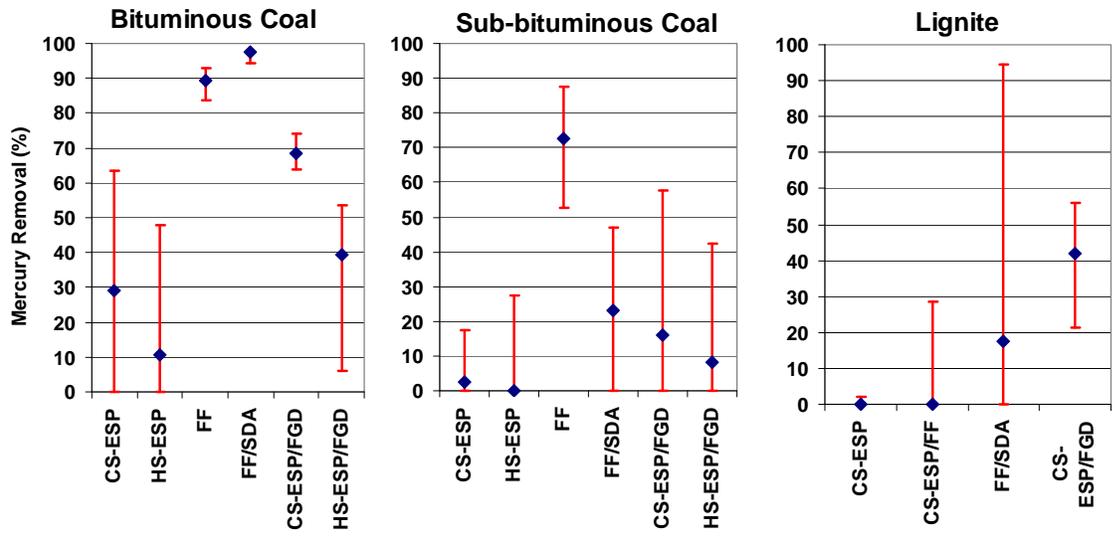
Figure 4. Effect of liquid-to-gas ratio on mercury emission at common operating pH values.[51]
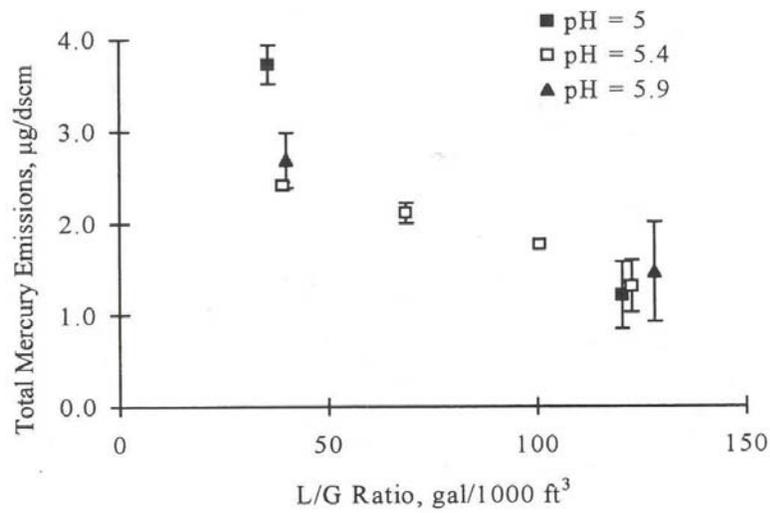
Figure 5. Mercury removal of various FGD systems
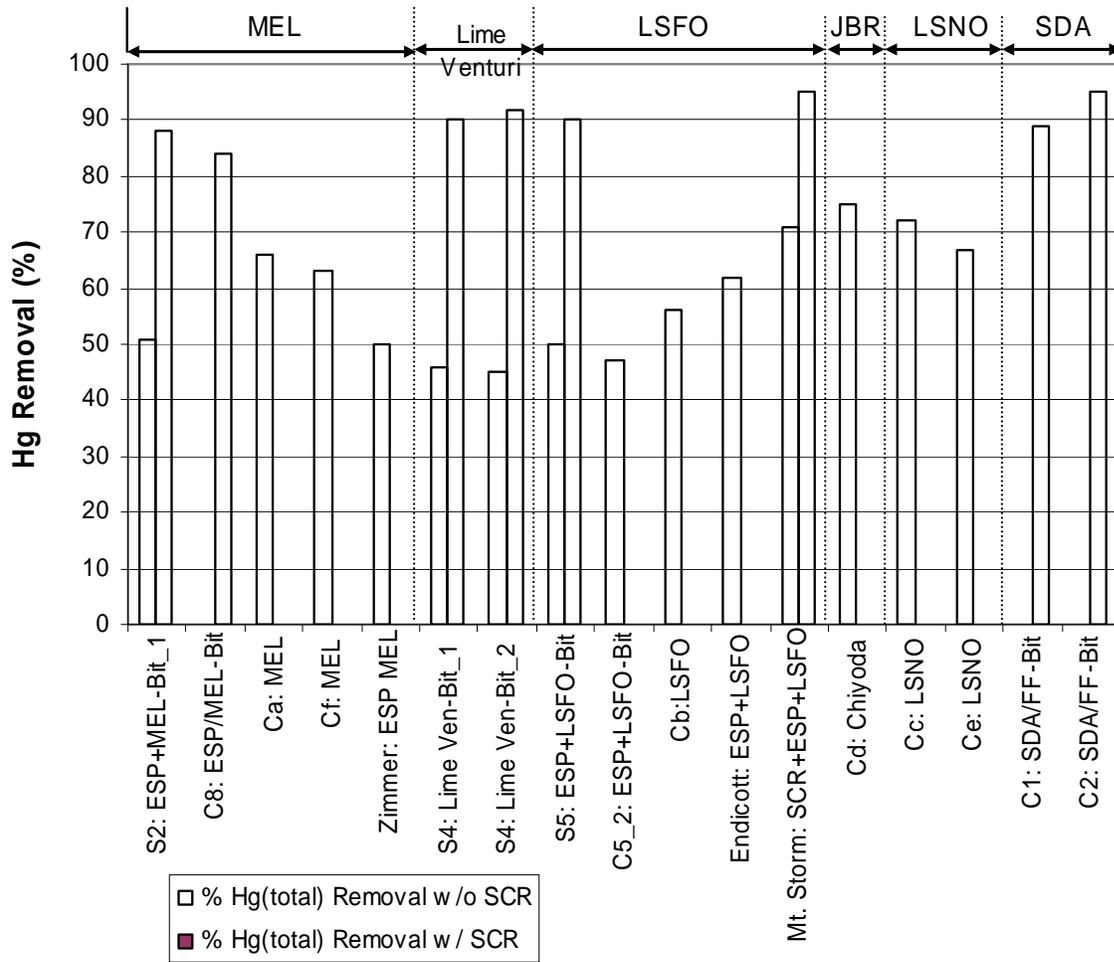
Figure 6. Percent oxidized mercury into ESP.
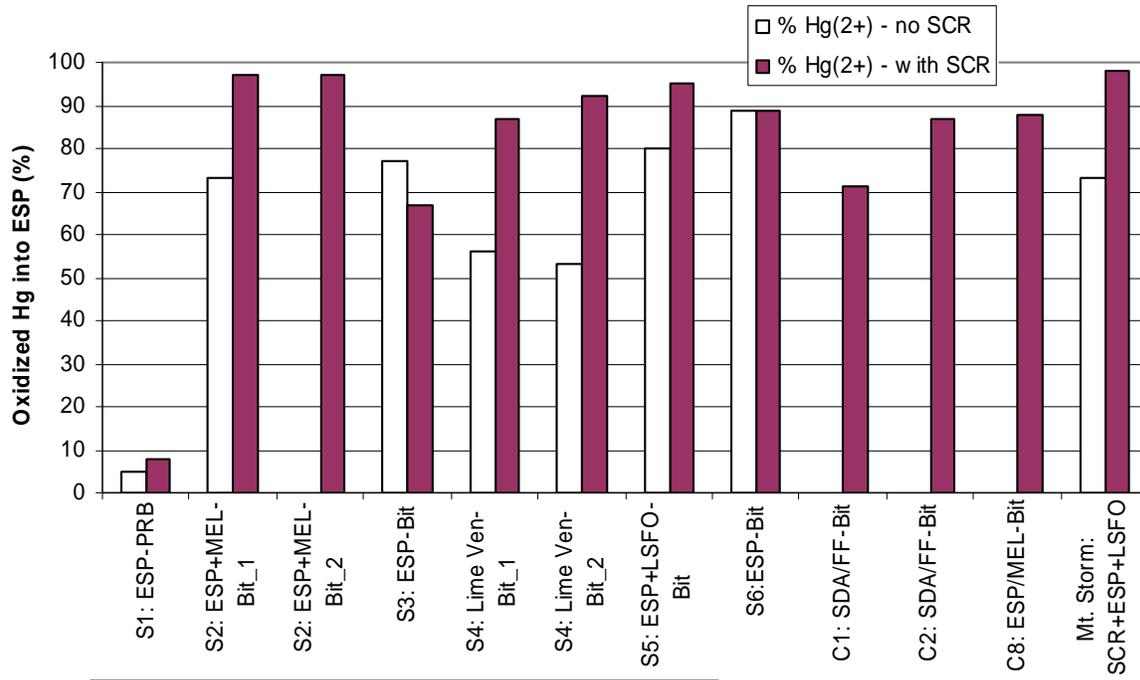
Figure 7. Options for enhancing mercury capture in existing air pollution controls.
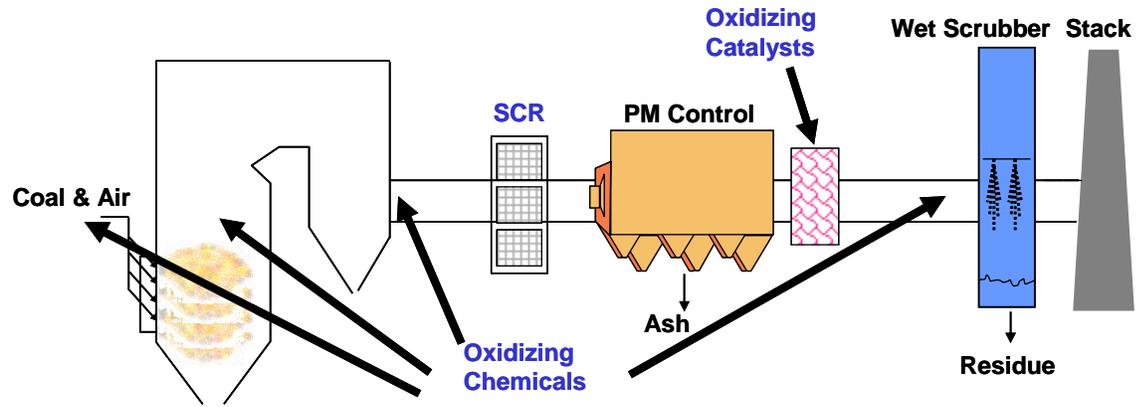
Figure 8. Parametric test results of mercury removal by standard PAC- all data using Norit FGD.
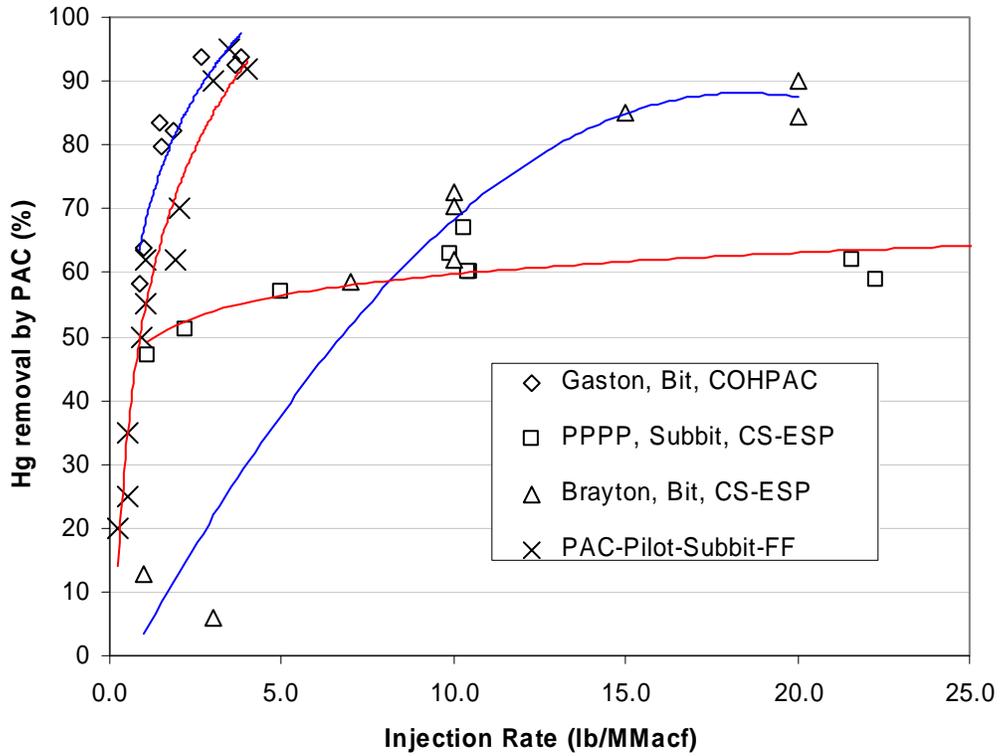
Figure 9. Results of relatively long-term PAC testing at Gaston [52]
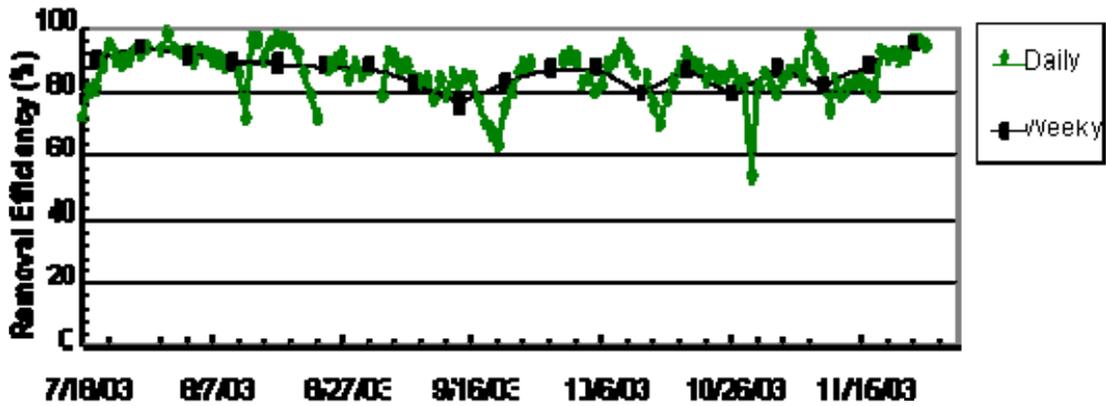
Figure 10. Comparison of mercury removal by B-PAC to that by standard PAC for injection upstream of CS-ESP; standard PAC data is with Norit FGD.
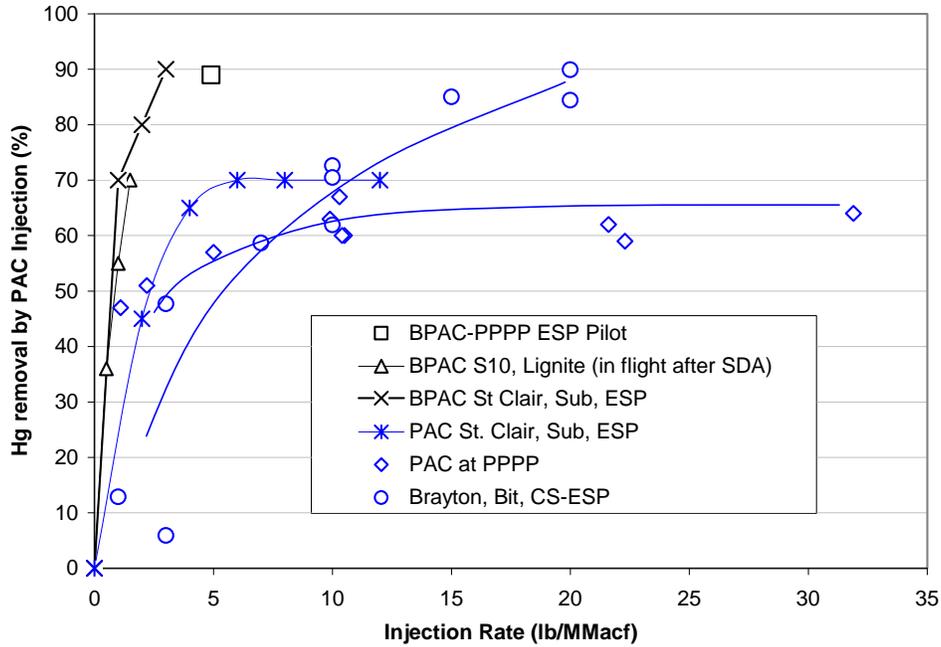
Figure 11. Comparison of mercury removal by B-PAC to that by standard PAC for injection upstream of FF; standard PAC data is with Norit FGD.
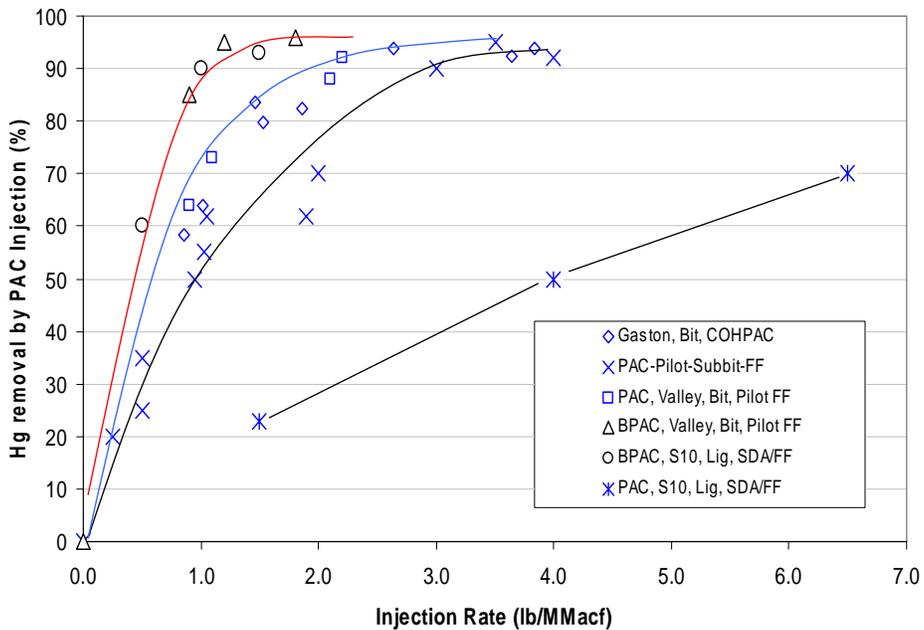
Figure 12. Performance of B-PAC in parametric tests are shown for in-flight and upstream of a fabric filter for various coal types.
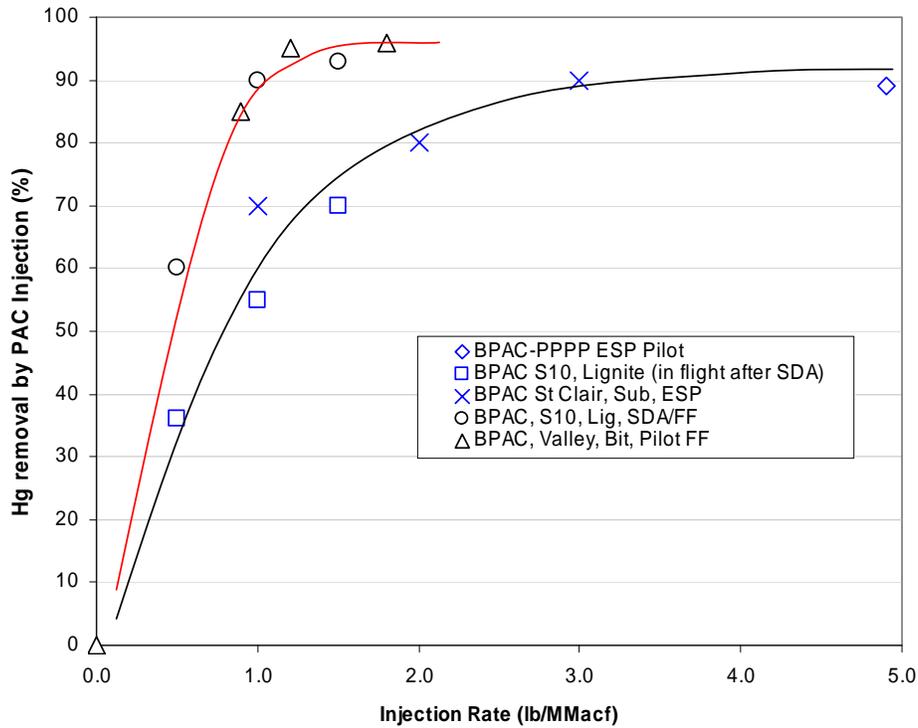
Figure 13. Performance of halogenated PACs versus that with standard PACs.[53]
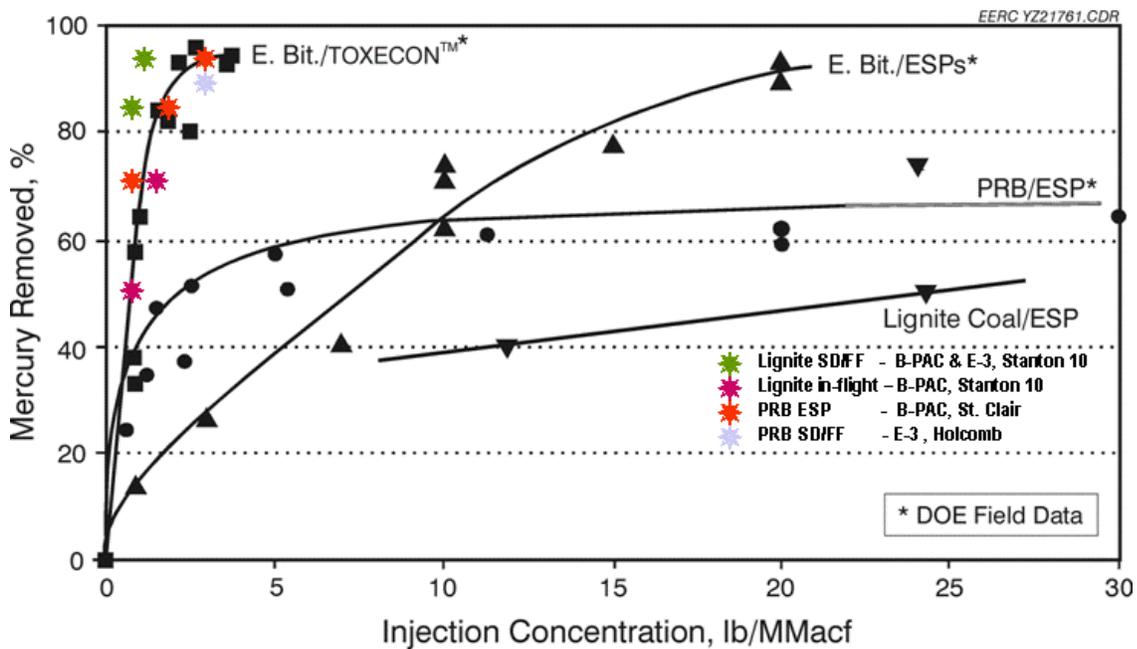
Figure 14. Results from DOE-sponsored 30-day full-scale testing at DTE St. Clair 80 MW boiler with CS-ESP, firing PRB and an 85:15 PRB:bituminous blend and using B-PAC.[54]
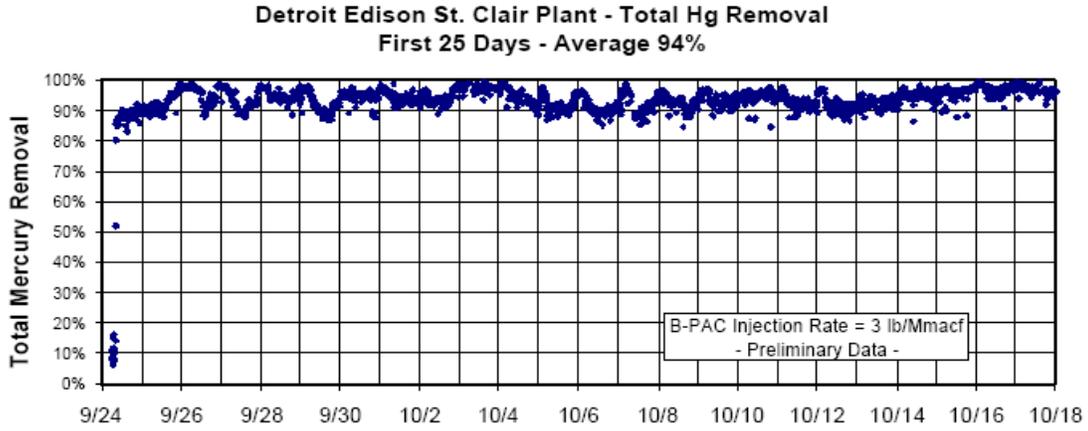
Figure 15. 10-day results from DOE-sponsored full-scale testing at Ameren Meramec 70 MW Unit 2 with CS-ESP, firing PRB and using Norit E-3.[55]
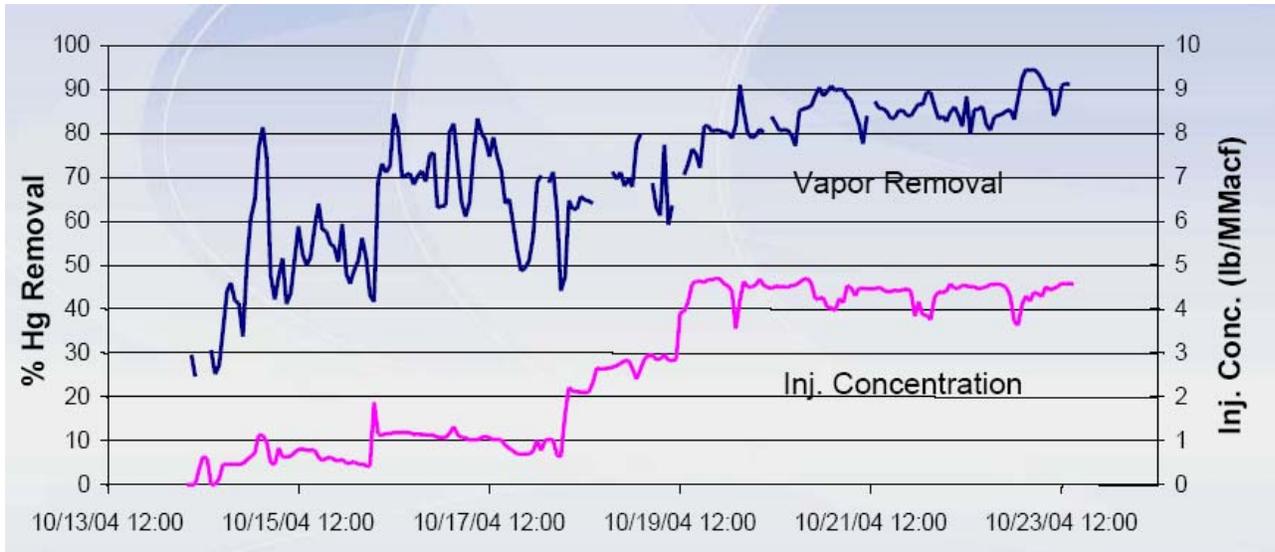
Figure 16. Results from DOE-sponsored 30-day full-scale testing at Holcomb 360 MW boiler with SD+FF, firing PRB blend and using Norit E-3. [55]
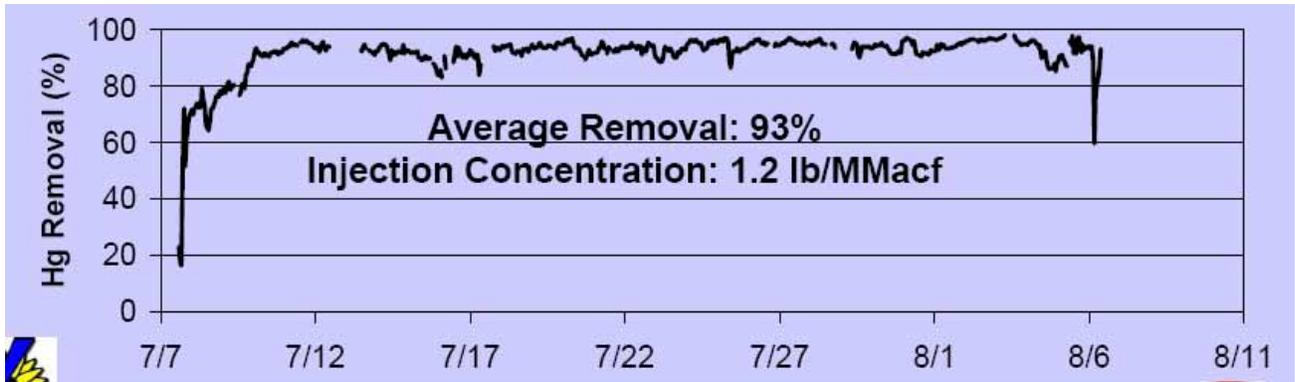

Figure 17. Calculated incremental particulate loading in the flue gas from sorbent injection
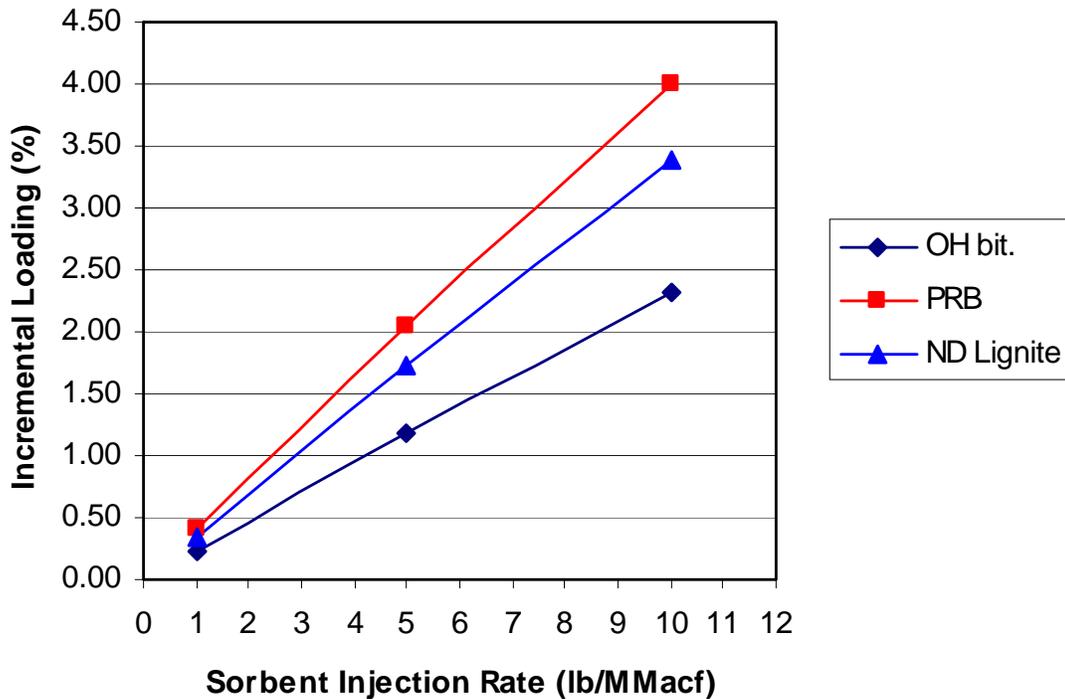
**Figure 18**. ESP power behavior at Brayton Point with increase in PAC injection rate. [56]
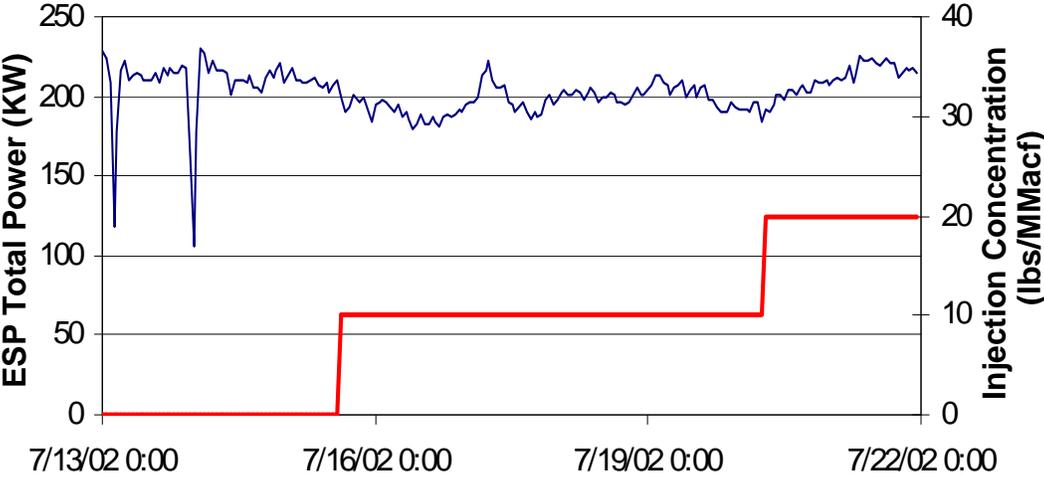
Figure 19. Estimated sorbent and disposal costs for sorbent injection upstream of a CS-ESP.
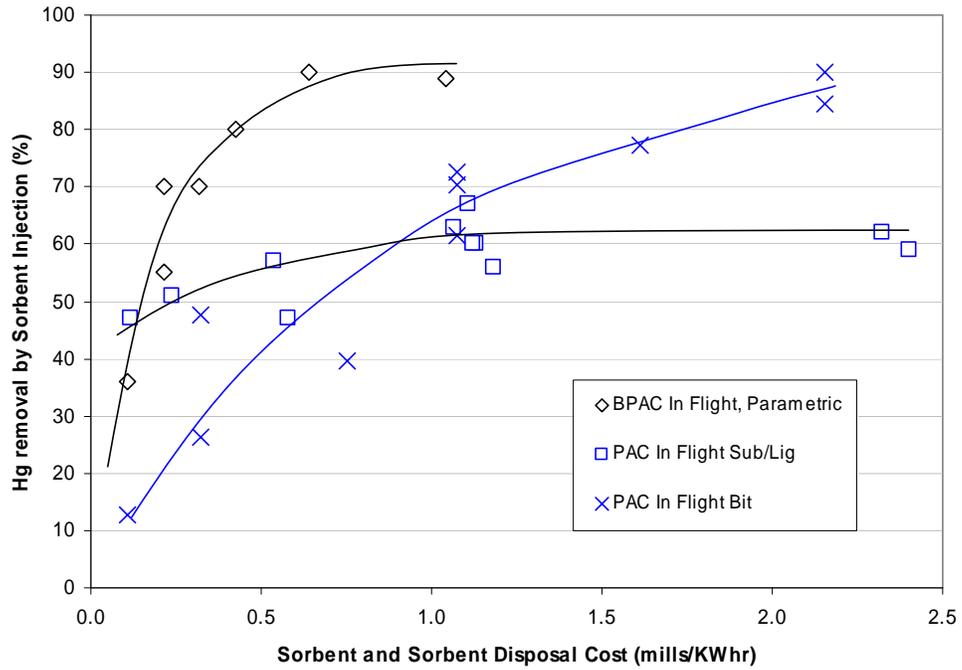

Figure 20. Estimated sorbent and disposal costs for sorbent injection upstream of an FF.
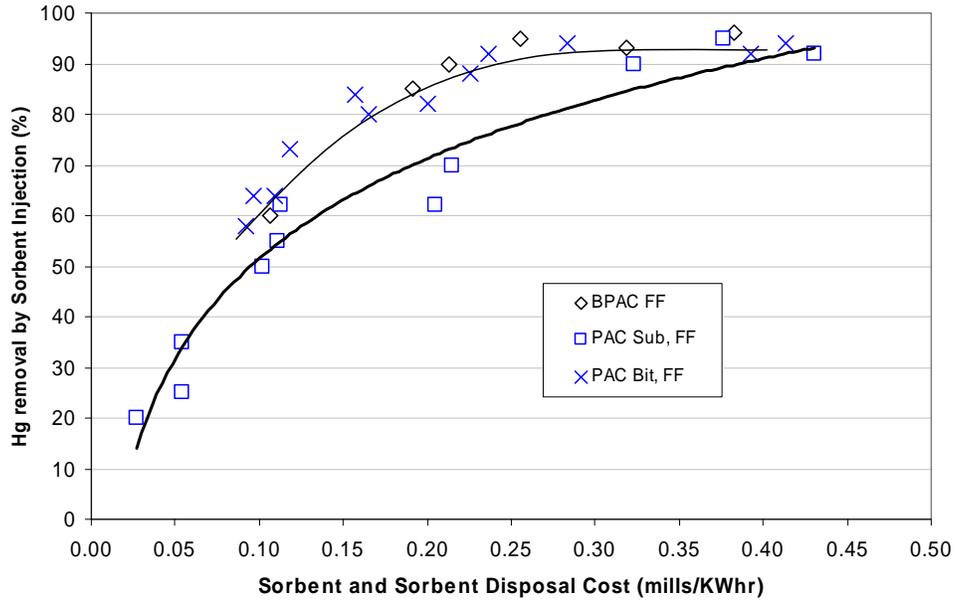
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