

CONTROL OF MERCURY EMISSIONS FROM COAL-FIRED ELECTRIC UTILITY BOILERS

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Introduction

During combustion, the mercury (Hg) in coal is volatilized and converted to elemental mercury (Hg^0) vapor in the high temperature regions of coal-fired boilers. As the flue gas is cooled, a series of complex reactions begin to convert Hg^0 to ionic mercury (Hg^{2+}) compounds and/or Hg compounds (Hg_p) that are in a solid-phase at flue gas cleaning temperatures or Hg that is adsorbed onto the surface of other particles. The presence of chlorine gas-phase equilibrium favors the formation of mercuric chloride (HgCl_2) at flue gas cleaning temperatures. However, Hg^0 oxidation reactions are kinetically limited and, as a result, Hg enters the flue gas cleaning device(s) as a mixture of Hg^0 , Hg^{2+} , and Hg_p . This partitioning of Hg into Hg^0 , Hg^{2+} , and Hg_p is known as mercury speciation, which can have considerable influence on selection of mercury control approaches. In general, the majority of gaseous mercury in bituminous coal-fired boilers is Hg^{2+} . On the other hand, the majority of gaseous mercury in subbituminous- and lignite-fired boilers is Hg^0 .

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 Hg_p in PM control equipment and soluble Hg^{2+} compounds in wet flue gas desulfurization (FGD) systems. Available data also reflect that use of selective catalytic reduction (SCR) NO_x control enhances oxidation of Hg^0 in flue gas and results in increased mercury removal in wet FGD.

Table 1 shows the average reduction in total mercury (Hg_T) emissions developed from EPA's Information Collection Request (ICR) data on U.S. coal-fired boilers. Plants that employ only PM controls experienced average Hg_T emission reductions ranging from 0 to 90 percent. Units with fabric filters (FFs) obtained the highest average levels of control. Decreasing average levels of control were generally observed for units equipped with a cold-side electrostatic precipitator (CS-ESP), hot-side ESP (HS-ESP), and particle scrubber (PS). For units equipped with dry scrubbers, the average Hg_T emission reductions ranged from 0 to 98 percent. The estimated average reductions for wet flue gas desulfurization (FGD) scrubbers were similar and ranged from 0 to 98 percent.

As seen in Table 1, in general, the amount of Hg captured by a given control technology is greater for bituminous coal than for either subbituminous coal or lignite. For example, the average capture of Hg in plants equipped with a CS-ESP is 36 percent for bituminous coal, 3 percent for subbituminous coal, and 0 percent for lignite. Based on ICR data, it is estimated that existing controls remove about 36% of the 75 tons of mercury input with coal in U.S. coal-fired boilers. This results in current emissions of 48 tons of mercury.

There are two broad approaches to mercury control: (1) activated carbon injection (ACI), and (2) multipollutant control, in which Hg capture is enhanced in existing/new SO₂, NO_x, and PM control devices. Relative to these two approaches, this paper describes currently available data, limitations, estimated potential, and Research Development and Demonstration (RD&D) needs. Depending on levels appropriated by congress, EPA may not be able to continue it's review of mercury removal technologies in fiscal year 2004.

Table 1. Average mercury capture by existing post-combustion control configurations used for PC-fired boilers

Post-combustion Control Strategy	Post-combustion Emission Control Device Configuration	Average Mercury Capture by Control Configuration		
		Coal Burned in Pulverized-coal-fired Boiler Unit		
		Bituminous Coal	Subbituminous Coal	Lignite
PM Control Only	CS-ESP	36 %	3%	0 %
	HS-ESP	9 %	6 %	not tested
	FF	90 %	72 %	not tested
	PS	not tested	9 %	not tested
PM Control and Spray Dryer Adsorber	SDA+CS-ESP	not tested	35 %	not tested
	SDA+FF	98 %	24 %	0 %
	SDA+FF+SCR	98 %	not tested	not tested
PM Control and Wet FGD System ^(a)	PS+FGD	12 %	0 %	33%
	CS-ESP+FGD	75 %	29 %	44 %
	HS-ESP+FGD	49 %	29 %	not tested
	FF+FGD	98 %	not tested	not tested

CS-ESP = cold-side electrostatic precipitator (a) Estimated capture across both control devices
 HS-ESP = hot-side electrostatic precipitator
 FF = fabric filter
 PS = particle scrubber
 SDA = spray dryer absorber system

State-of-the-art of Controlling Mercury Emissions by Activated Carbon Injection

ACI has the potential to achieve moderate to high levels of Hg control. The performance of an activated carbon is related to its physical and chemical characteristics. Generally, the physical properties of interest are surface area, pore size distribution, and particle size distribution. The capacity for Hg capture generally increases with increasing surface area and pore volume. The ability of Hg and other sorbates to penetrate into the interior of a particle is related to pore size distribution. The pores of the carbon sorbent must be large enough to provide free access to internal surface area by Hg⁰ and Hg²⁺ while avoiding excessive blockage by previously adsorbed reactants. As particle sizes decrease, access to the internal surface area of particle increases along with potential adsorption rates.

Carbon sorbent capacity is dependent on temperature, the concentration of Hg in the flue gas, the flue gas composition, and other factors. In general, the capacity for adsorbing Hg²⁺ will be different than that for Hg⁰. The selection of a carbon for a given application would take into consideration the total concentration of Hg, the relative amounts of Hg⁰ and Hg²⁺, the flue gas composition, and the method of capture [electrostatic precipitator (ESP), FF, or dry FGD scrubber].

ACI may be used either in conjunction with existing control technologies and/or with additional control such as the addition of an FF. To date ACI has only been evaluated during short-term tests on commercially operating electrical generating plants. Longer-term tests of ACI have been limited to continuous operation, 24 hr/day-7days/week, for a period of less than two weeks at four field test sites. Also, combustion modification, such as coal reburning technology, may increase the carbon in fly ash and yield enhanced Hg capture in PM control devices

The Department of Energy/National Energy Technology Laboratory (DOE/NETL), the Electric Power Research Institute (EPRI) and a group of utility companies have funded projects to evaluate the use of ACI as summarized in Table 2. The Hg removal via ACI is measured between the inlet and outlet of the particulate matter control device. Note that these projects represent ACI applications that can be used to control Hg emissions from units that (1) are currently equipped with an ESP; and (2) burning bituminous or subbituminous coals. The tests at Alabama's Gaston Plant show the potential Hg control levels that can be achieved by installing a compact hybrid particulate collector (COHPAC) or small pulse-jet FF downstream of an existing ESP and injecting activated carbon upstream of the COHPAC unit.

Table 2. ACI 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	

A mobile sorbent injection system and a mobile test laboratory were constructed for use at all test sites except Abbott. Norit lignite-based carbon, Darco-FGD, was used as the benchmark sorbent at all test sites. Tests at the sites generally included:

- the use of Apogee Scientific semi-continuous emission monitors (S-CEMs) for measurement of Hg^0 and total vapor-phase Hg (Hg_v);
- periodic measurements of Hg_p , Hg^{2+} and Hg^0 with the Ontario-hydro (OH) method;
- laboratory and slipstream sorbent screening tests;
- baseline tests without the use of sorbents;
- parametric tests to evaluate the effects of process conditions and sorbent variables; and
- 4- to 9-day tests with Darco-FGD.

The purpose of tests at each site was to determine the performance and costs of activated carbon sorbents for controlling Hg emission from coal-fired electrical generating plants equipped only with an ESP. The field tests are summarized below.

Brayton Point

ACI testing was conducted on the 245-MW Unit 1, which fired a low-sulfur bituminous coal with 0.03 ppm Hg and 2000-4000 ppm chlorine. The unit is equipped with low- NO_x burners and typically has high levels of unburned carbon (UBC) in the fly ash as indicated by loss on ignition (LOI) measurements. The PM control system at the unit is unusual in that it consists of two CS-ESPs in series and long duct runs. Carbon was injected between the ESPs.

The average baseline removal efficiency across both ESPs averaged 90.8 percent, as measured during three tests with the OH method. During parametric tests, a variety of activated carbons, including Darco-FGD, were injected just downstream of the first ESP. Incremental Hg removal efficiencies across the second ESP ranged from 3 to 93 percent depending on the carbon injection concentration. Total average Hg removal efficiencies across both ESPs as determined by the S-CEMs averaged 94.5 percent during injection of Darco-FGD at 10 lb/MMacf.

Longer-term performance tests involved the continuous injection of Darco-FGD 24 hours/day for 10 days at two different injection concentrations. Five days of injection at 10 $\mu\text{g}/\text{dnm}$ was followed by five days of injection at 20 $\mu\text{g}/\text{dnm}$. The average removal efficiency across both ESPs during ACI concentrations of 10 lb/MMacf was 94.5 percent as measured during 3 OH method tests. These high Hg capture efficiencies are considered to be atypical of other CS-ESP units because of the high UBC concentrations, the two ESPs, and the long duct runs.

Salem Harbor

Tests were conducted on Unit 1, an 88 MW single wall-fired unit which is equipped with low- NO_x burners, a selective noncatalytic reduction (SNCR) system for NO_x control and a CS-ESP. Salem Harbor fires a South American low-sulfur bituminous coal with 0.03-0.08 ppm Hg and 206 ppm chlorine. The resulting fly ash had an LOI of 20 to 30 percent.

Parametric tests at reduced loads that lowered fly ash LOI to 15 to 20 percent did not significantly reduce Hg capture. Increasing the ESP inlet temperature from 300°F to 350°F reduced Hg removal from approximately 90 percent to the 10-20 percent range. The effects of

changes in LOI over test range of 15 to 30 percent were not as strong as the effects of temperature changes.

During November 2002, four days of long-term sorbent injection tests were conducted with Darco-FGD at an injection concentration of 10 lb/MMacf. The average Hg capture efficiency during 3 OH tests was 94.0 percent. The Hg⁰ concentrations for all inlet and outlet samples were below the method detection limit. More than 95 percent of the total inlet Hg was measured as Hg_p, indicating nearly complete in-flight capture of Hg upstream of the ESP. The very high in-flight Hg capture by the UBC in fly ash and injected activated carbon are not believed to be representative of plants equipped with a CS-ESP.

Pleasant Prairie

ACI testing was conducted on the 600-MW Unit 2, which fired a PRB coal with 0.11 ppm Hg and 8 ppm chlorine. The unit is equipped with an ESP. Testing was conducted on one ESP chamber (1/4 of the unit). The plant sells its fly ash for use in concrete.

Baseline tests using the OH method exhibited Hg capture in the ESP of about 5 percent with more than 70 percent of the Hg at the ESP inlet being Hg⁰. Major parametric test variables included sorbent properties and sorbent injection concentration. At low ACI concentrations, Hg reductions across the ESP were higher than expected, reaching 60 to 65 percent at injection concentrations near 10 lb/MMacf. Increasing sorbent injection concentrations to 20 to 30 lb/MMacf increased Hg reduction efficiencies to only about 70 percent. Subsequently, in long-term tests carbon was injected continuously at 24 h/day for 5 days. OH measurements confirmed that about 60-70% mercury removal could be achieved at a carbon injection concentration of 10 lb/MMacf.

Gaston

ACI testing was conducted on the 270-MW Unit 3, which fired low-sulfur eastern bituminous coals with 0.14 ppm Hg and 160 ppm chlorine. The unit is equipped with low-NO_x burners, a HS-ESP and a COHPAC, which was retrofit earlier to capture residual fly ash escaping the ESP. Testing was conducted on one-half of the flue gas stream.

Baseline test results showed that neither the HS-ESP nor COHPAC captured a significant amount of Hg. During ACI parametric tests, Hg capture efficiencies ranged from 25 to more than 90 percent, depending on the carbon injection rate. ACI concentrations of 3 lb/MMacf resulted in gas-phase Hg reductions greater than 90 percent across the COHPAC. However, it was determined that ACI resulted in a significant increase in COHPAC cleaning frequency. The different activated carbons used in the parametric tests produced Hg capture efficiencies similar to Darco-FGD, the benchmark sorbent. Differences in sorbent particle size or base material (bituminous coal or lignite) did not result in appreciable performance differences. Subsequently, in long-term tests, carbon was injected continuously at 24 h/day for 9 days. The COHPAC cleaning frequency and ACI rate was kept at a reduced level to avoid adverse impacts on COHPAC bag life. Relatively short duration OH measurements reflected about 90% removal of mercury, but measurements taken with S-CEMS reflected about 78% removal over the period of the long-term testing.

Abbott

In the summer of 2001, EPRI sponsored ACI tests at the Abbott Power Plant located in Champaign, Illinois. Unit 5, the test unit, is a stoker-fired unit followed by air heater and a CS-ESP. During the tests, Unit 5 burned an Illinois Basin coal with nominal sulfur and chlorine contents of 3.8 and 0.25%, respectively. Activated carbons used during the parametric tests included Darco FGD, fine FGD (size segregated Darco FGD), and an experimental Corn Char sorbent.

During the parametric tests ACI concentrations were varied from 5.1 to 20.5 lb/MMacf. The ESP inlet temperatures ranged from 340 to 390 °F. The performance of Darco FGD and the corn char sorbents were similar, showing increases in Hg capture proportional to the ACI concentration. The fine FGD sorbent exhibited improved performance relative to the standard FGD. The best performance, 73% Hg 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 activated carbon. This is consistent with bench-scale research that shows that high SO₂ concentrations diminished the adsorption capacity of activated carbons.

Recently, EPA has estimated cost for ACI-based controls.¹ These estimates range from 0.03-3.096 mills/kWh. However, the higher costs are usually associated with the plant configuration utilizing SDA+CS-ESP or HS-ESPs. Excluding the costs associated with the plant configurations involving SDA + ESP or HS-ESP, cost estimates are from 0.03 to 1.903 mills/kWh. At the low end of this cost range, 0.03 mills/kWh, it is assumed that no additional control technologies are needed, but mercury monitoring will be necessary.

RD&D Needs for Sorbent Injection Systems

In order to enhance the cost effective capture of Hg by ACI, and other sorbent injection systems, for the important coal type/retrofit control combinations, the following RD&D efforts are needed.

- Research efforts on Hg speciation and capture should be continued. These efforts will include bench- and pilot-scale investigations on the effects of flue gas composition, fly ash properties (UBC content and catalytic metal content), flue gas quench rates, and other important parameters. Speciation and capture computer models must be developed to evaluate field test results and for application to other utility sites.
- Development and demonstration of low cost sorbents, impregnated sorbents and innovative sorbents that are effective in controlling Hg emissions from subbituminous coal and lignite should continue. High temperature sorbents for use with HS-ESPs also should be investigated.
- Development and demonstration of techniques to improve Hg capture in units equipped with an ESP, SDA/ESP or SDA/FF and burn subbituminous coal and lignite is needed.

¹ Performance and Cost of Mercury and Multipollutant Emission Control Technology Applications on Electric Utility Boilers, EPA/600/R-03/110, October 2003, United States Environmental Protection Agency, Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC.

This will include evaluation of coal blending, combustion modifications, use of oxidizing reagents, and use of impregnated sorbents.

- Evaluation and demonstration of cost-effective ESP retrofit approaches including installation of ducting to increase residence times and use of circulating fluidized bed absorbers for optimal utilization of sorbents should be conducted. The use of multipollutant sorbents that capture SO₂ and Hg should also be investigated.
- Determination and demonstration of optimum design and operating conditions for COHPAC applications on a range of boiler operating conditions is needed. This will include evaluation of the effects of air-to-cloth ratios, fabric filter material, cleaning frequencies, and baghouse arrangements on Hg capture. COHPAC-based tests should be conducted with both mercury and multipollutant sorbents.
- Continued evaluation of potential leaching or re-emission of mercury from sorbent/ash residues that are disposed of or utilized is needed.

Mercury Control by Enhancing the Capability of Existing/New SO₂/NO_x Controls

Implementation of fine PM standards, EPA's Interstate Air Quality Rule, Utility MACT rulemaking to control mercury emissions from utility boilers, the Clear Skies legislation and other multi-pollutant reduction bills in the Congress are focusing on future reductions of NO_x, SO₂, and mercury emissions from power plants. Also, a significant fraction of existing boiler capacity already has wet or dry scrubbers for SO₂ control and /or SCR for NO_x control. As such, multipollutant control approaches capable of providing SO₂/NO_x/Hg reductions are of great interest. These approaches and their potential impact on mercury reductions are discussed below.

Multipollutant Removal in Wet FGD

More than 20 percent of coal-fired utility boiler capacity in the United States uses wet FGD systems to control SO₂ emissions. In such systems, a PM control device is installed upstream of the wet FGD scrubber. Wet FGD systems remove gaseous SO₂ from flue gas by absorption. For SO₂ absorption, gaseous SO₂ is contacted with a caustic slurry, typically water and limestone or water and lime.

Gaseous compounds of Hg²⁺ are generally water-soluble and can absorb in the aqueous slurry of a wet FGD system. However, gaseous Hg⁰ is insoluble in water and therefore does not absorb in such slurries. When gaseous compounds of Hg²⁺ are absorbed in the liquid slurry of a wet FGD system, the dissolved species are believed to react with dissolved sulfides from the flue gas, such as H₂S, to form mercuric sulfide (HgS); the HgS precipitates from the liquid solution as sludge.

The capture of Hg in units equipped with wet FGD scrubbers is dependent on the relative amount of Hg²⁺ in the inlet flue gas and on the PM control technology used. ICR data reflected that average Hg captures ranged from 29 percent for one PC-fired ESP plus FGD unit burning subbituminous coal to 98 percent in a PC-fired FF plus FGD unit burning bituminous coal. The high Hg capture in the FF plus FGD unit was attributed to increased oxidization and capture of Hg in the FF followed by capture of any remaining Hg²⁺ in the wet scrubber.

RD&D Needs for Wet FGD Systems to Enhance Mercury Capture

- Achieving high Hg removal efficiencies in a wet scrubber depends on mercury in the flue gas being present in the soluble Hg^{2+} form. While the majority of mercury in bituminous coal-fired boilers exists as Hg^{2+} , the fraction available as Hg^{2+} varies. Further, as discussed above, flue gases from subbituminous and lignite coal-fired boilers predominantly contain Hg^0 , which is insoluble. Therefore, to ensure high levels of mercury capture in wet scrubbers in a broad range of applications, process means for oxidizing Hg^0 in coal combustion flue gas are needed. RD&D efforts should be conducted with the objective of making available oxidizing catalysts and reagents by 2015. Also, RD&D efforts should be undertaken to examine coal blending as a means to increase oxidized mercury content in flue gas.
- Scrubber design and operating conditions may require modification to optimize Hg dissolution in the scrubber liquor. Therefore, optimization research should be undertaken at pilot-scale and then demonstrated at full-scale.
- It has been noted that in some scrubbers dissolved Hg^{2+} is reduced to Hg^0 , which can be stripped from the scrubbing liquor and entrained in the stack gas. RD&D efforts should be conducted in this area with additives developed in bench- and pilot-scale testing and demonstrated at full-scale.
- Since a significant portion of the absorbed Hg may end up in the spent scrubber liquor in the form of dissolved aqueous-phase Hg^{2+} , RD&D should be conducted to develop Hg removal techniques from wastewater.
- RD&D efforts should be conducted to make available multipollutant scrubbers capable of removing SO_2 , Hg, and NO_x from flue gases of coal-fired boilers. Research conducted in the 1970s through 90s has investigated removal of NO_x in wet scrubbers. Since use of wet scrubbers at power plants is expected to increase in the near future in response to regulatory requirements, it is very desirable to develop wet scrubber-based technologies capable of providing simultaneous SO_2 -Hg- NO_x control. Such technologies would not only make wet scrubbers more cost-effective, but would avoid the need for installing additional control equipment, especially at constrained plant layouts.
- Full-scale demonstrations should be conducted to achieve high levels of mercury control using ACI with wet FGD, with or without additional oxidizing agents. This is especially relevant to subbituminous- and lignite-fired boilers.

Multipollutant Removal in Dry Scrubbers

More than 10 percent of the U.S. coal-fired utility boiler capacity uses spray dryer absorber (SDA) systems to control SO_2 emissions. An SDA system operates by the same principle as a wet FGD system using a lime scrubbing agent, except that the flue gas is mixed with a fine mist of lime slurry instead of a bulk liquid (as in wet scrubbing). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate. Hg^{2+} may also be absorbed. Sorbent particles containing SO_2 and Hg are captured in the downstream PM control device (either an ESP or FF). If the PM control device is a FF, there is the potential

for additional capture of gaseous Hg^0 as the flue gas passes through the bag filter cake composed of fly ash and dried slurry particles.

ICR data reflected that units equipped with SDA scrubbers (SDA/ESP or SDA/FF systems) exhibited average Hg captures ranging from 98 percent for units burning bituminous coals to 24 percent for units burning subbituminous coal.

RD&D Needs for Dry Systems to Enhance Mercury Capture

- SDA is considered to be quite effective in removing Hg^{2+} from flue gases. Full-scale demonstrations of SDA and ACI should be conducted to achieve high levels of SO_2 and mercury controls on subbituminous and lignite-fired boilers. These demonstrations should include both ESP and FF PM controls.
- Circulating fluidized bed absorber technology appears promising to provide high levels of SO_2 and Hg control. Recent applications of this technology reflect SO_2 control in excess of 90%. As for mercury control, limited pilot-scale experience has shown high mercury removal rates. This technology, with or without ACI, should be demonstrated for mercury control in several full-scale tests using a range of coals.

Multipollutant Removal Via SCR and Wet FGD

As mentioned above, the speciation of mercury is known to have a significant impact on the ability of air pollution control equipment to capture it. In particular, the oxidized form of mercury, mercuric chloride (HgCl_2), is highly water-soluble and is, therefore, easier to capture in wet FGD systems than Hg^0 which is not water-soluble. SCR catalysts can act to oxidize a significant portion of the Hg^0 , thereby enhancing the capture of mercury in downstream wet FGD.

Several studies have suggested that oxidation of elemental mercury by SCR catalyst may be affected by the following:

- The space velocity of the catalyst;
- The temperature of the reaction;
- The concentration of ammonia;
- The age of the catalyst; and
- The concentration of chlorine in the gas stream.

DOE, EPRI, and EPA have co-sponsored a field test program that evaluated mercury oxidation across full-scale utility boiler SCR systems. Testing was performed at four coal-fired electric utility plants having catalyst age ranging from around 2500 hours to about 8000 hours. One plant fired subbituminous coal and three other plants fired Eastern bituminous coal. The test results showed high levels of mercury oxidation in two of the three plants firing eastern bituminous coal and insignificant oxidation at the other two plants (one firing bituminous coal and the other, subbituminous). For the bituminous coal-fired plant with low mercury oxidation, over 50 percent of the mercury at the SCR inlet was already in the oxidized form. It is also noted that the SCR system at this plant was operated with significantly higher space velocity (3930 hr^{-1}) than those of

the other plants (1800-2275 hr⁻¹). Finally, ammonia appeared to have little or no effect on mercury oxidation.

The two bituminous coal-fired plants at which high levels of mercury oxidation across SCRs was observed were retested in the following year (2002). Again, similar high levels of oxidation were observed. Two additional plants firing bituminous coals were also tested in 2002. Results of the tests showed high levels of mercury oxidation, similar to the two plants tested previously. Currently, a DOE-sponsored field test program is further evaluating the potential effect of SCRs and FGDs on mercury removal.

RD&D Needs for SCR and Wet FGD Systems to Enhance Mercury Capture

- Aging of SCR catalyst with regard to mercury oxidation should be examined in bench-, pilot-, and field tests.
- SCR impact on mercury oxidation should be examined for subbituminous and lignite-coal-fired boilers and boilers firing coal blends. These impacts should be evaluated on pilot- and field-scales.
- Bench- and pilot-scale research on understanding the science behind SCR-Hg interactions should be continued. This research has the potential to provide valuable information for optimizing SCR catalysts for combined NO_x and mercury control.

Potential Impact of Coal Use and Availability of NO_x/SO₂ Controls on Mercury Control

In general, the extent to which mercury control approaches discussed above may be utilized in the future would depend on the extent to which coal would be used in U.S. power plants and the availability of existing/new NO_x/SO₂ emission controls in response to potential emission reduction requirements.

Figures 1 and 2 depict projected United States coal consumption and production trends for the United States, respectively. It is evident from Figure 1 that the majority of coal consumed in the U.S. is by the electric power generation sector and that this consumption rate is expected to increase in the future. Figure 2 reflects that the amount of low-sulfur coals (e.g., subbituminous coals) produced has been significant and this production is expected to increase in the future. Based on these data, it can be deduced that consumption of low-sulfur coals in the power generation sector is expected to increase in the future. As discussed above, control of mercury emissions from boilers firing low-rank (subbituminous and lignite) coals is more difficult than from boilers firing bituminous coals. Considering the projected increase in use of low-sulfur (i.e., low-rank) coals, it is important that cost-effective approaches for controlling mercury emissions from boilers firing such coals be developed via focused RD&D efforts.

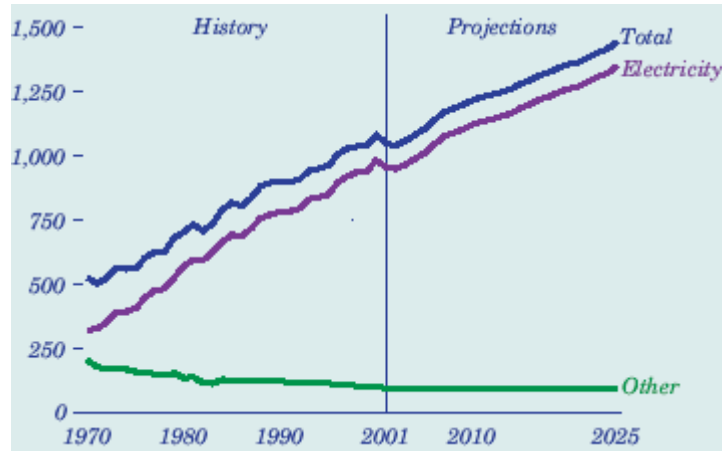


Figure 1. Electricity and other coal consumption (million short tons).²

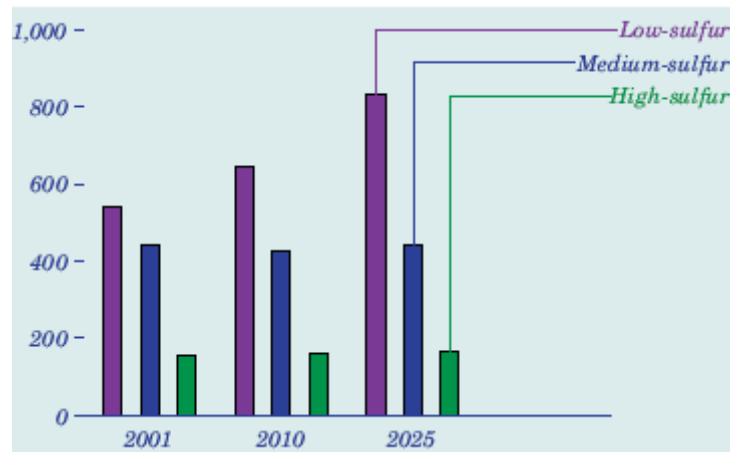


Figure 2. Projected coal production (million short tons) by sulfur content.²

The trends in coal-fired capacity equipped with SCR and scrubbers based on EPA's analysis of Clear Skies Act are shown in Figures 3 and 4, respectively. It is clear from these figures that current and future NO_x and SO₂ emission reduction requirements are expected to result in large capacities (about 100 GW each) of SCR and scrubber systems for coal-fired utility boilers, as early as 2005. Further, these capacities are expected to increase at steady and significant rates. These projections underscore the need to engage in focused RD&D efforts to determine cost-effective means for optimizing/tweaking these NO_x/SO₂ controls to achieve mercury control as a co-benefit with small incremental costs.

² Source: Annual Energy Outlook 2003 with Projections to 2025, DOE/EIA-0383(2003), Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC 20585, January 2003.

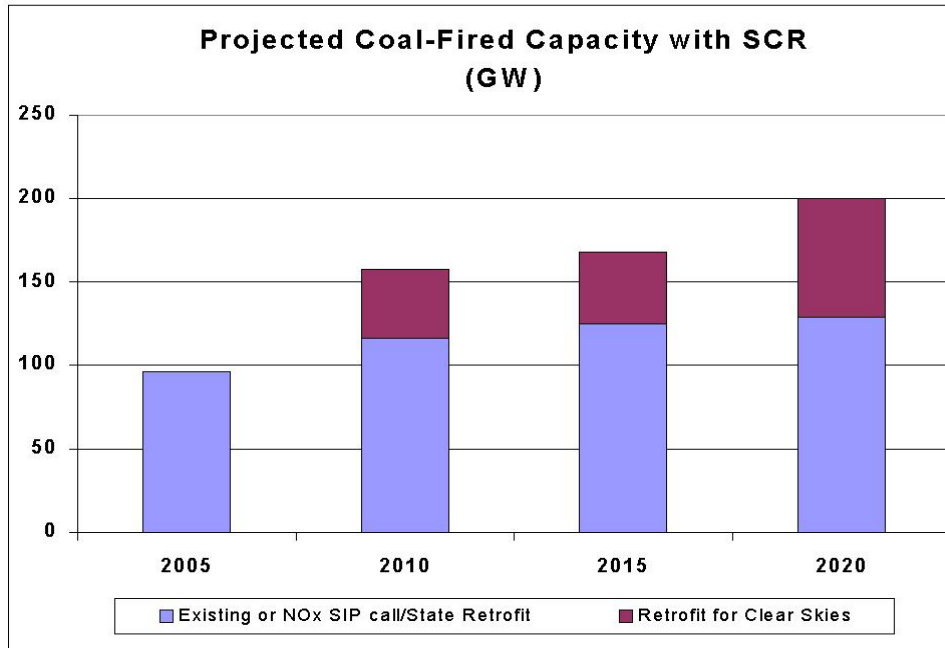


Figure 3. Projected capacity of SCR applications on U.S. coal-fired utility boilers.³

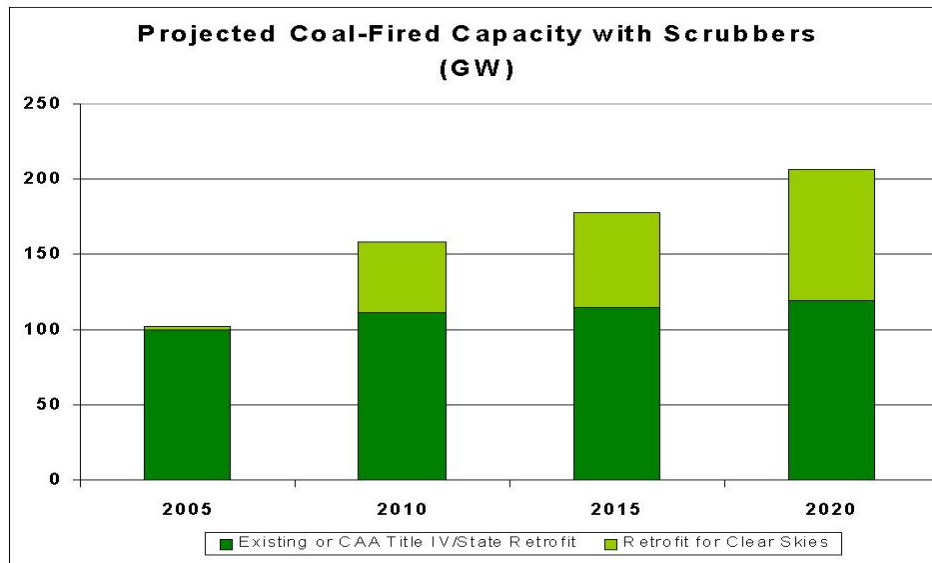


Figure 4. Projected capacity of scrubber applications on U.S. coal-fired utility boilers.³

³ Source: “2003 Technical Support Package for Clear Skies: Section D: 2003 projected impacts on generation and fuel use,” available at <http://www.epa.gov/air/clearskies/technical.html>.

Summary and Conclusions

Although the potential Hg emissions are calculated to be 75 tons per year based on the Hg content in coal, the actual current emissions are estimated to be 48 tons per year due to Hg capture with pollution controls for PM and SO₂. The reduction at any individual plant ranges from 0 to 98% dependent on coal type, control technology type, and other unquantified factors.

A very limited set of short term full-scale trials of activated carbon injection have been carried out as described earlier in this white paper. These trials do not cover a representative range of control technology/fuel combination that would be required to demonstrate the widely achievable levels of Hg control that might be achieved in a cost effective manner. Furthermore, they represent short-term (4-9 day) continuous operation and do not address all of the operational issues and residue impacts that may be associated with commercial operation. Therefore, these technologies are not currently commercially proven to consistently achieve high levels of Hg control on a long-term basis.

These data provide a basis for hypothesizing the levels of Hg reductions that might be achievable using technology specifically for Hg control alone or enhanced capture in existing or new systems for control of SO₂ and NO_x. These estimates contained in Table 3 are based on best engineering judgment and the assumption that a focused RD&D program is carried out in an effective and expeditious manner.

Key observations are as follows:

1. The database clearly indicates that Hg emission controls for low-rank (subbituminous and lignite) coal-fired boilers are more difficult than for bituminous-fired boilers. Further, a significant amount of low-rank coal is currently being used by the electric utility industry, and this use is expected to increase in the future. Accordingly, it is important to engage in focused RD&D efforts aimed at developing emission controls for low-rank coal-fired boilers.
2. Assuming sufficient development and demonstrations are carried out, by 2010, ACI with an ESP has the potential to achieve 70% Hg control. ACI with an ESP and a retrofit fabric filter, or a fabric filter alone, has the potential to achieve 90% Hg reduction. Proper design and consideration of operational and residue impacts need to be incorporated into the effort.
3. Projections reflect that current and future NO_x and SO₂ emission reduction requirements are expected to result in large capacities (over 100 GW each) of SCR and scrubber systems for coal-fired utility boilers, as early as 2005. Further, these capacities are expected to increase at steady and significant rates. Ongoing R&D has the potential to provide the basis for enhanced Hg removal in retrofitted system by 2010. Assuming sufficient research development and demonstration of representative technologies, by 2015 new and existing systems installed to control NO_x and SO₂ (e.g., SCR+FGD+FF) have the potential to achieve 90 to 95% control of Hg. Subbituminous and lignite systems may require Hg oxidation technology and/or additional advanced sorbents to achieve these levels. The longer timeframe for these systems is driven by the fact that more R&D is required to optimize Hg control approaches before demonstrations are conducted.

4. Cost estimates fall in a wide range. It is projected that the Hg removal capabilities projected in Table 3 would add no more than about 3 mills/kWh to the annualized cost of power production. Control by an enhancing/optimizing FGD and SCR has the potential to reduce such costs substantially, since optimized systems may require little additional investment and/or operational costs, especially for bituminous coals.
5. The projected performance in Table 3 represents the date by which the demonstration of the most difficult case (e.g., lignite) for the particular technology would be completed. The demonstrations of the technology for easier situations (e.g., high-chlorine bituminous coal) could be completed somewhat earlier. It is important to note that completion of such demonstrations would represent only the potential **initiation** of the retrofit program which would take a number of years to fully implement, assuming of course, both successful demonstrations and a regulatory driving force. The time it would take to fully deploy such technologies would depend on a number of factors, including the specifics of the regulatory mandates, available vendor capability to meet the hardware demand, and the time for design and construction of the specific retrofit technologies selected.

Based on our 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 timeframe:

- ACI on an existing ESP or FF could be installed in approximately 1 year;
 - ACI and a retrofit fabric filter (e.g., COHPAC) could be retrofitted to an existing ESP in approximately 2 years; and
 - a new SCR/FGD/PM/Hg control system could be retrofitted in 3-4 years dependent on the retrofit difficulty.
 - existing SCR or FGD to enhance Hg control could be retrofitted in about one year
6. Table 3 also reflects the existing capacities associated with key coal type/control technology combinations. These capacities, with the exception of CS-ESP + retrofit FF and PM + dry FGD, are significant, thereby underscoring the fact that development of mercury control approaches would need to take into consideration these key coal type/control technology combinations. The relatively low capacity associated with the CS-ESP + retrofit FF combination is not surprising because in the absence of mercury reduction requirements, relatively few plants have used this combination to control residual amounts of fly ash escaping their ESPs. Again the relatively low capacity associated with PM + dry FGD is a result of the present economics associated with sulfur reduction via wet or dry FGD or firing low-sulfur coal. However, as discussed above, in the presence of mercury reduction requirements, these latter combinations will offer attractive mercury control approaches.

Table 3. RD&D goals for projected cost-effective mercury removal capability (%) for key coal type/control technology combinations.⁴

Control Technology	Existing Capacity (MW) in 2003 ⁵	Projected Hg Removal Capability in 2010 by the Use of ACI ⁴		Projected Hg Removal Capability in 2010 by Enhanced Multipollutant Controls ⁴		Projected Hg Removal Capability in 2015 by Optimizing Multipollutant Controls ⁴	
		Bituminous (Bit)	Low-rank coals	Bit. Coals	Low-rank coals	Bit. Coals	Low-rank coals
PM Control Only-CS-ESP	153133	70 ⁶	70 ⁶	NA ⁷	NA	NA	NA
PM Control Only-CS-ESP + retrofit FF	2591	90	90	NA	NA	NA	NA
PM Control Only-FF	11018	90	90	NA	NA	NA	NA
PM + Dry FGD	8919	NA	NA	90 ⁸	60-70 ⁸	90-95 ⁸	90-95 ⁸
PM + Wet FGD	48318	NA	NA	90 ⁹	70-80 ⁹	90-95 ⁹	90-95 ⁹
PM + Wet or Dry FGD + SCR	22586	NA	NA	90	70-80 ¹⁰	90-95 ¹⁰	90-95 ¹⁰

⁴ Based on the assumption of aggressive RD&D implementation as outlined elsewhere in this white paper.

⁵ Capacity values have been obtained from EMF controls available in “EPA’s 2003 Clear Skies Act parsed file for 2010” available at <http://www.epa.gov/airmarkets/epa-ipm/results2003.html>. The capacity values have been rounded to the nearest whole number.

⁶ This control level is based on data from the Pleasant Prairie field tests.

⁷ NA = not applicable.

⁸ Assumes that additional means to ensure oxidation of Hg⁰ or innovative sorbents will be used as needed.

⁹ Assumes that means to oxidize Hg⁰ will be used as needed. Note that in some cases this may, in part, be accomplished by FF.

¹⁰ Assumes that additional means to ensure oxidation of Hg⁰ or innovative sorbents will be used as needed.