Preliminary Estimates of Performance and Cost of Mercury Emission Control Technology Applications on Electric Utility Boilers: An Update

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ABSTRACT

The Environmental Protection Agency has recently proposed a reduction in mercury emissions from coal-fired power plants. There are two broad approaches under development to controlling mercury emissions from coal-fired electric utility boilers: (1) powdered activated carbon (PAC) injection, and (2) multipollutant control, in which Hg capture is enhanced in existing and new sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) control devices. To help inform the recent EPA rulemaking proposal, estimates of performance levels and related costs associated with the above mercury control approaches were developed. This work presents these estimates.

Estimates of cost for PAC injection range from 0.03-3.096 mills/kWh. In general, the higher costs are associated with the plants using spray dryers and electrostatic precipitators (ESPs) or plants using hot-side ESPs, which represent a minority of power plants. Excluding these plants, cost estimates range between 0.03 and 1.903 mills/kWh. At the low end of the cost ranges, 0.03 mills/kWh, it is assumed that no additional control technologies are needed, but mercury monitoring will be necessary. In these cases, high mercury removal may be the result of the type of NO_x and SO_2 control measures currently employed, such as combinations of selective catalytic reduction and wet flue gas desulfurization on bituminous coal fired boilers.

Since mercury control approaches are under development at present, cost and performance estimates are preliminary and are expected to be refined as mercury control technologies are matured to commercial status. Factors that may affect the performance of these technologies include speciation of mercury in flue gas, the characteristics of the sorbent, and the type(s) of PM, NO_x and SO_2 controls employed. The effect of these factors may not be entirely accounted for in the data points that form the basis for this work. Ongoing research is expected to address these issues.

INTRODUCTION

Since mercury is an element, it cannot be created or destroyed. In the atmosphere, mercury exists in two forms: elemental mercury vapor (Hg^0) and ionic mercury (Hg^{2+}). Hg^0 can circulate in the atmosphere for up to one year and, consequently, can undergo dispersion over regional and global scales. Hg^{2+} in the atmosphere is either bound to airborne particles or exists in gaseous form. This form of mercury is readily removed from the atmosphere by wet and dry deposition. After deposition, mercury is commonly re-emitted back to the atmosphere as either a gas or a constituent of particles and re-deposited elsewhere. In this fashion, mercury cycles in the environment.[1]

A number of human health and environmental impacts are associated with exposure to mercury. Mercury is known to bioaccumulate in fish and animal tissue in its most toxic form, methylmercury. Human exposure to methylmercury has been associated with serious neurological and developmental effects. Adverse effects of mercury on fish, birds, and mammals include reduced reproductive success, impaired growth, behavioral abnormalities, and even death. Details of the risks associated with exposure to mercury are discussed in the literature.[2] A severe case of human exposure occurred in Minamata, Japan, in the 1950s.[3]

Coal-fired power plants in the U.S. are known to be the major anthropogenic source of mercury emissions.[1, 4] The Environmental Protection Agency has recently proposed to reduce mercury emissions from these plants.[5] There are two broad approaches to controlling mercury emissions from coal-fired electric utility boilers: (1) powdered activated carbon (PAC) injection, and (2) multipollutant control, in which Hg capture is enhanced in existing and new sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) control devices. Mercury capture via these approaches has thus far been investigated in relatively short-term tests on commercially operating electrical generating plants. As such these approaches are under development. Based on current information and assuming sufficient research development and demonstration efforts are undertaken, it is projected that PAC injection technology and multipollutant control will be available for commercial application after 2010. Nevertheless, considering the current interest in the potential of mercury controls, EPA evaluated the costs associated with application of these controls,[6] and has recently updated these costs based on recent data.[7] This paper presents the revised cost estimates. Additional details on these costs can be found in Reference 7. Since mercury control technologies are still under development, the cost estimates presented are considered to be preliminary.

MERCURY SPECIATION AND CAPTURE IN EXISTING EQUIPMENT

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.[8] 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 known to be Hg^{2+}. On the other hand, the majority of gaseous mercury in subbituminous- and lignite-fired boilers is Hg^0.[9]

Control of mercury emissions from coal-fired boilers is currently being 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[10,11,12,13] 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.[14] Plants that employ only PM controls experienced average Hg_T emission reductions ranging from 0 to 90% percent. Of these, 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%. The estimated average reductions for wet FGD scrubbers were similar and ranged from 0 to 98%.

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% for bituminous coal, 3% for subbituminous coal, and 0% 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.[9]

There are a number of parameters that impact the mercury removal by existing equipment. Chlorine is widely acknowledged as having a role in mercury removal. SO_2 is also expected to have a role as well. Fly ash characteristics and the temperature of the exhaust gas leaving the air preheater exit have also demonstrated a strong influence on mercury removal. Of course, the equipment type plays an important role as well.

Based on statistical analyses of ICR data, predictive correlations for capture of Hg in existing equipment have been developed.[15] These correlations approximate the effects of equipment type, coal chlorine content, and SO_2 level on Hg removal in existing equipment. The algorithms are:

Algorithm 1 (ESPc):

$$f_{\text{existing equipment}} = C_1 \times \ln\left[(\text{coal Cl, ppm})/(SO_2\text{, in lb/MMBtu})\right] + C_2 \qquad \text{Eq. 1}$$

Algorithm 2 (all other categories):

$$f_{\text{existing equipment}} = C_1 \times \ln(\text{coal Cl, ppm}) + C_2 \qquad \text{Eq. 2}$$

Where $f_{\text{existing equipment}}$ is the fraction of mercury removed by existing equipment. There are minimum and maximum allowable values that set the allowable range for the results of Equations 1 and 2. Table 2 shows values for C_1 and C_2 and minimum and maximum values to use in Equations 1 and 2 for estimating fraction of mercury removed by existing equipment.

Note that the above expressions do not include other the effects of other factors such as ash characteristics and gas temperature. Since these factors can have a significant effect on the mercury capture in existing facilities, the above expressions should only be used for making approximate estimates.[16]

ADDITIONAL MERCURY CONTROL REQUIREMENT

If $f_{\text{equipment i}}$ is equal to the fraction of mercury removed from the boiler gases by a specific piece of equipment i, then $(1 - f_{\text{equipment i}})$ equals the fraction of mercury remaining in the gases after that specific equipment. The fraction of mercury remaining after n pieces of equipment is equal to

$$[(1 - f_{\text{equipment 1}}) \times (1 - f_{\text{equipment 2}}) \times (1 - f_{\text{equipment 3}}) \times . . . \times (1 - f_{\text{equipment n}})] \qquad \text{Eq. 3}$$

Therefore, the total mercury removal fraction, f_{Total}, is

$$f_{\text{Total}} = 1 - [(1 - f_{\text{equipment 1}}) \times (1 - f_{\text{equipment 2}}) \times (1 - f_{\text{equipment 3}}) \times . . . \times (1 - f_{\text{equipment n}})] \qquad \text{Eq. 4}$$

If one of the n pieces of equipment represents a mercury control system, $f_{\text{mercury control}}$, Eq. 4 becomes

$$f_{\text{Total}} = 1 - [(1 - f_{\text{existing equipment}}) \times (1 - f_{\text{mercury control}})] \qquad \text{Eq. 5}$$

where $f_{\text{existing equipment}}$ is the removal fraction associated with the existing equipment and may be approximated by Equations 1 and 2 if the removal by existing equipment is not known.

COSTS OF CARBON INJECTION-BASED MERCURY CONTROLS

Injection of powered activated carbon (PAC) sorbent has been successfully used on municipal waste combustors (MWCs) for Hg control Despite differences between MWCs and utility boilers (e.g., mercury concentration and speciation in the flue gas), full-scale and pilot-scale tests indicate that these technologies may be able to provide significant mercury removal from the flue gas of coal-fired utility boilers.[17,18,19,20,21,22,23,24]

To date PAC injection has only been evaluated during short-term tests on commercially operating electrical generating plants. Longer-term tests of PAC injection have been limited to continuous operation, 24 hr/day-7days/week, for a period of less than two weeks at four field test sites. Test programs have been performed on a utility boiler firing subbituminous coal with a downstream CS-ESP, on utility boilers firing bituminous coal with a downstream CS-ESP, and on a utility boiler firing bituminous coal with a Compact Hybrid Particle Collector (COHPAC) arrangement (upstream HS-ESP with downstream baghouse after the air preheater).[24] The above test programs have revealed the need to further evaluate PAC injection based approaches on utility boilers with regard to impact on plant operation and arriving at optimized controls.

This section describes EPA's recent evaluation of costs associated with applications of PAC injection-based control technologies that can be retrofitted to existing boilers for control of mercury emissions. It is recognized, however, that these costs are preliminary because additional efforts need to be made to mature these approaches to broadly applicable commercial status.

PAC Injection Rates

If PAC injection is used for mercury control, then using Eq. 5 the total mercury removal fraction is

$$f_{\text{Total}} = 1 - [(1 - f_{\text{existing equipment}}) \times (1 - f_{\text{PAC injection}})]. \qquad \text{Eq. 6}$$

where $f_{\text{PAC injection}}$ is the fraction of mercury removed by PAC injection.

Then solving for $f_{\text{PAC injection}}$

$$f_{\text{PAC injection}} = 1 - [(1 - f_{\text{Total}}) / (1 - f_{\text{existing equipment}})] \qquad \text{Eq. 7}$$

Given a total mercury reduction requirement and knowing the reduction by existing equipment, Eq. 7 can be used to determine how much additional reduction is needed from PAC injection.

Reference 6 expressed the relationship between mercury reduction and PAC injection as follows:

$$\% \text{ reduction} = \eta = 100 \times f_{\text{from PAC injection}} = 100 - [A/(M+B)^{C}] \qquad \text{Eq. 8}$$

where M is the mass injection rate of PAC (in lb/MMacf) and A, B, and C are curve-fit constants determined using available data. However, Eq. 7 is of a form in which it is possible to approach 100 percent mercury removal by injection of PAC at very high rates. But field data reflects that in some cases mercury reduction by PAC injection may be limited to a value well below 100 percent. To accommodate this consideration, in this work Eq. 8 was modified to

$$\% \text{ reduction} = \eta = 100 \times f_{\text{from PAC injection}} = 100^*D-[A/(M+B)^C] \qquad \text{Eq. 9}$$

so that

$$M = \{[A/\{(100 \bullet D) - \eta\}]^{(1/C)}\} - B \qquad \text{Eq. 10}$$

where D is the fraction of mercury reduction that is asymptotically approached.

If $f_{\text{existing equipment}}$ is less than f_{Total}, additional mercury removal via PAC injection, $f_{\text{from PAC injection}}$, is determined using Eq.7. Then considering $\eta = 100 \times f_{\text{from PAC injection}}$, Eq. 10 is used to determine M, the injection concentration of PAC (in lbs/MMacf). M is then multiplied by the total gas flow rate to determine the injection rate of PAC (in lbs per hour).

The set of constants A, B, C, and D appearing in Eq. 10 was considered to be a function of five parameters: the type of existing particulate control, the existing SO_2 control, coal type (bituminous or subbituminous), retrofit equipment (whether or not a FF is retrofit), and the PAC adsorption characteristics (low, medium, or high). For each situation of interest, this set was determined by curve fitting Eq. 10 against full-scale data where available, and based on pilot-scale data where full-scale data were not available. Reference 16 showed that for systems with FFs, all of the PAC-based sorbents appeared to offer similar performance in terms of PAC injection concentration (in lb/MMacf) necessary for a given mercury reduction. On the other hand, for units with ESPs and without a FF, PAC selection did have a significant effect on performance. Constants A, B, C, and D are described in Table 3 for each situation of interest.

Note that a slightly modified form of Eq. 10 was implemented in the cost estimation effort. This form is:

$$M = [\max(0.2, \{[A/\{(100 \bullet D) - \eta\}]^{(1/C)}\}) - B] \qquad \text{Eq. 11}$$

The above equation is essentially Eq. 10 with the sole difference that a minimum injection concentration of 0.2 lb/MMacf was set whenever PAC injection was determined to be necessary. For very low mercury removal rates – below that of the measured results – the curve-fit Eq. 10 could result in zero or negative PAC injection concentrations. Therefore, this minimum was set to avoid zeroing of the algorithm at low removal rates, which, in general, are rarely of interest. In most cases where PAC injection is necessary, this minimum will not apply because greater than 0.2 lb/MMacf results from Equation 11.

Model Plant Cases, Plant Characteristics, and Fuel Types

Costs for installing and operating the PAC injection-based technologies described above are estimated using model plants. Approximately 75% of the existing coal-fired utility boilers in the U.S. are equipped with electrostatic precipitators for controlling PM emissions; the remaining boilers employ FFs, PS, or other equipment.[5] Additionally, units firing medium-to-high sulfur coals may use FGD technologies to meet their SO_2 control requirements. Generally, larger units firing high sulfur coals employ wet FGD, while smaller units may use spray dryers. While developing the model plants, these PM and SO_2 control possibilities were taken into account.

Several model plants with possible flue gas cleaning equipment configurations and firing either bituminous or subbituminous coal were used in this work. Table 4 exhibits these model plants and associated mercury controls, and associated power plant characteristics are given in Table 5. Note that boiler sizes of 100 and 975 MW used in this work were selected to approximately span the range of existing boiler sizes, and to be consistent with the size of the model plants used in previous work reported in Reference 6. In addition, for plants firing high sulfur units and utilizing wet FGD additional model plants with 300 MW boilers were considered because wet FGD is a capital-intensive technology and is unlikely to be selected over other approaches for SO_2 control on a unit as small as 100 MW. It was also envisioned that use of SCR can enhance oxidation of mercury in flue gas and result in the "co-benefit" of increased mercury removal in wet FGD. Since SCR is a capital-intensive technology, generally its use is cost-effective on larger boiler sizes. Accordingly, in this work, the mercury co-benefit resulting from SCR use was evaluated for model plants utilizing large (975 and 300 MW) boilers and wet FGD.

Three different coal types were evaluated for estimating costs of mercury control options with the model plant cases shown above. These coals included a high sulfur bituminous coal, a low sulfur bituminous coal, and a PRB coal. The properties of these coals are shown in Table 6.

Development of Cost Estimates

Costs are comprised of capital and operating costs. These costs are assessed to develop a total annual cost of pollution control expressed in mills/kWh or $/MWh, which are equal numerically. The total installed capital cost is annualized to produce an annual charge. This is done by multiplying the total installed capital charge by a Capital Recovery Factor (CRF). The CRF is a function of variables such as project life, cost of capital, tax rate, depreciation methods, and other. In this analysis a CRF of 0.133 (or 13.3 percent) was chosen to be consistent with Reference 6. The annualized capital charge is then divided by the total power output of the plant for the year to determine the Annual Capital Cost contribution to electric cost in mills/kWh (or $/MWh).

In general, capital costs of PAC injection-based technologies comprise a relatively minor fraction of the total annual costs of these technologies; the major fraction is associated with the costs related to the use of PAC.[25] Therefore, for such technologies, an assessment of costs needs to be based on total annual costs. These costs include annualized capital charge, annual fixed operation and maintenance (O&M) costs, and annual variable O&M costs.

In this effort, costs are determined on a constant dollar basis – that is to say that the costs are represented in 2003 dollars and the effects of general inflation are, therefore, normalized. We also assume that the escalation of operating costs equals the general inflation rate. Therefore, inflation is assumed to offset escalation so that the levelization factor for operating costs is equal to 1.0.

While developing the cost estimates for the model plant applications, the following specifications were used.

1. Mercury concentration in the coal was taken to be 0.10 mg/kg for eastern bituminous coal and 0.07 mg/kg for subbituminous coal. These concentrations are in the range of concentration reported for utility boilers in Reference 26.

2. PAC injection rate correlations (see Eq. 10 and Table 3) generally reflect that PAC injection requirements increase nonlinearly with an increase in mercury removal efficiency. To characterize the impact of this behavior, wherever possible, model plant cost estimates were obtained for total (i.e., capture in existing equipment and any additional capture needed via PAC injection) mercury removal efficiencies of 50, 60, 70, 80, and 90 percent. In some cases existing equipment may provide in excess of 50 percent removal and PAC injection may not be needed to achieve the specified level of reduction. For PAC injection with a downstream ESP, 90 percent reduction may not be possible with subbituminous coals without retrofit of a downstream pulse-jet fabric filter (PJFF). For bituminous coal fired boilers with an ESP, 90 percent removal may not be cost effective by PAC injection alone, when compared to PAC injection and retrofit of a downstream PJFF.

3. Spray cooling was not used in any of these model runs because for most temperatures of interest (air preheater exit temperature under 350 °F), PAC has sufficiently high capacity that any temperature effect is expected to be small. Moreover, spray cooling may have adverse effects on high-sulfur fuel boilers (due to acid dew point effects) and PRB fuel boilers (due to cement-like properties of the ash). However, at lignite coal-fired plants, which were not evaluated here, spray cooling might be used to improve mercury removal.

4. No data are currently available for recycling of sorbent in technology applications utilizing PAC injection and PJFF. Accordingly, no sorbent recycle was used.

5. Wet FGD performance for mercury control is determined by Eq. 2 if no SCR exists or 90 percent removal if the boiler fires bituminous coal and is equipped with an SCR. No oxidation (or co-benefit) by SCR is assumed for subbituminous coals. If PAC is added to provide additional reduction of mercury, then PAC is added upstream of the ESP or FF.

6. In each of the model plant cost determinations, a plant capacity factor of 65 percent was used.

7. The cost of PAC was taken to be $1,000/ton of carbon.

8. In the case of subbituminous coal + spray dryer (SD), it is assumed that PAC is added upstream of the SD, and a FF may be added between the upstream PAC injection point and the downstream SD. This is because the removal of HCl by the SD may adversely affect the ability of PAC to achieve reasonable removal rates of Hg. This will require a larger fabric filter than if the fabric filter were installed downstream of the existing

particulate control device because in the upstream arrangement the fabric filter would need to be sized to capture all of the fly ash as well as the injected PAC.

9. Costs include capital and operating costs associated with any retrofit control and the expected costs associated with a continuous emission monitoring system (CEMS) for mercury.

10. In this analysis it was assumed that the percent mercury removal possible from additional controls was not affected by the mercury removal from existing controls. While it is possible that there may be some interaction, this is not expected to be a significant effect for the cases evaluated here.

11. In all of the cases evaluated here, the cost calculations conservatively assumed that all collected fly ash is currently sold. Therefore, calculations for PAC injection in configurations where fly ash and PAC are collected together include incremental costs to landfill fly ash at a cost of $30/ton. In many cases these costs will not be incremental because landfilling of fly ash may be in practice prior to mercury control application or because fly ash may not be rendered completely unacceptable for re-use.

    The large majority of plants currently landfill their flyash[7] and for them PAC injection would increase disposal costs only in proportion to PAC usage. Also, in situations where flyash is currently sold, depending upon the amount of PAC added, the properties of the fly ash, and the intended use of the sold ash, fly ash contaminated with some used PAC might still be beneficially reused. According to ASTM Standard C618-03, coal fly ash with carbon contents as high as 6 percent may be acceptable as a concrete additive.[27] There are other criteria that may determine acceptability of the fly ash as an additive to a buyer. However, the presence of small amounts of carbon in the fly ash may not necessarily render it unacceptable for beneficial re-use.

12. Application of mercury or multipollutant controls has the potential for leaching or re-emission of mercury from residues (e.g., sorbent/ash, scrubber sludge) that are disposed of or utilized. This potential is currently under investigation. In this analysis it was assumed that no efforts would be needed to stabilize mercury in such residues.

Cost Results

This section describes the estimates of total annual cost for mercury control technology applications on the model plants.

Boilers firing high-sulfur bituminous coals and utilizing CS-ESP and wet FGD (model plants A, D). As shown in Tables 7a and 7b, existing equipment (CS-ESP and wet FGD) are expected to provide 67.7 percent mercury removal and injection of PAC is required if greater mercury removal is needed. Under these conditions, to achieve 80-90 percent mercury removal, PAC injection between the CS-ESP and a retrofit downstream PJFF is more economical than just PAC injection before the existing CS-ESP. Based on this finding, up to 90 percent mercury removal may be achieved at costs less than 1.5 mills/kWh.

With the SCR, PAC injection is not expected to be necessary for achieving 90 percent removal of mercury and the cost of 0.003-0.004 mills/kWh is that associated with mercury emissions monitoring (mercury CEMS). For higher than 90 percent mercury removal, PAC injection may be necessary.

Boilers firing high-sulfur bituminous coals and utilizing FF and wet FGD (model plants B, E). When a facility is equipped with a fabric filter and an FGD system, 96 percent mercury removal is expected from existing equipment. Consequently, no PAC injection is needed to achieve up to 96 percent mercury control. Again, costs of 0.003-0.004 mills/kWh, associated with mercury emissions monitoring (mercury CEMS), would be the only costs associated with such plants. Also for such plants, SCR co-benefit is not significant because mercury removal in existing equipment is expected to be higher than 90 percent.

Boilers firing high-sulfur bituminous coals and utilizing HS- ESP and wet FGD (model plants C, F, O). For such plants, the existing equipment, HS-ESP followed by a wet FGD, will provide about 65 percent mercury removal and PAC injection is needed to achieve greater removal. Since operational temperatures of HS-ESPs are higher than those at which PAC injection is appropriate, it is assumed that a low temperature PJFF will be retrofitted after the HS-ESP and air preheater. PAC will be injected upstream of the retrofit PJFF. Tables 8a and 8b show the cost estimates. As shown in Table 8a, up to 90 percent mercury removal may be achieved at costs less than 2.0 mills/kWh. Also, as seen in Table 8b for units with SCR, up to 90 percent removal may be achieved at costs of 0.003-0.004 mills/kWh, i.e., costs associated with mercury monitoring. Thus co-benefit of SCR has substantial cost impacts because PAC injection is needed with a downstream PJFF at units without SCR.

Boilers firing high-sulfur bituminous coals and utilizing SD and CS-ESP (model plant M). Table 9. For high sulfur fuels, a SD with a downstream CS-ESP is not expected to be very effective for mercury removal. Therefore, most of the mercury removal must be performed by additional PAC injection. In this case, a PJFF may be installed upstream of the SD and must be sized for collection of the full ash loading plus the PAC injection. Alternatively, a smaller polishing PJFF may be installed downstream of the existing CS-ESP (i.e., the COHPAC option). Cost results reflect that it may be more economical to install a polishing PJFF downstream of the ESP and still inject the PAC upstream of the SD, than to install a PJFF sized for collection of the full ash loading plus the PAC injection. With the COHPAC option, up to 90 percent mercury removal may be achieved at costs less than 2.0 mills/kWh. However, it is recognized that at present data is not available on this type of application.

Boilers firing high-sulfur bituminous coals and utilizing SD and FF (model plant N). As shown in Table 10, a SD with a downstream fabric filter is expected to provide high mercury removal, approaching 90 percent. A small amount of PAC might be added upstream of the SD to provide some more mercury reduction at a relatively low cost. The results reflect that up to 90 percent mercury removal may be achieved at costs less than 0.5 mills/kWh.

Boilers firing low-sulfur bituminous coals and utilizing CS-ESP (model plants G, P). For these cases, PAC injection is expected to be necessary for mercury reduction in excess of 50 percent.

As shown in Table 11, for the 975 MW plant case addition of a PJFF improves overall economics for removal in excess of 70 percent and up to 90 percent mercury control may be achieved at costs less than 1.5 mills/kWh. However, for a smaller 100 MW plant, the addition of a polishing PJFF is more economical only for the 90 percent mercury removal case at costs less than 2.0 mills/kWh.

Boilers firing low-sulfur bituminous coals and utilizing FF (model plants H, Q). As shown in Table 12, due to the high mercury removal expected from existing equipment in these cases, PAC injection is only expected to be necessary for mercury reduction in excess of 85 percent. For neither the 975 MW plant, nor the 100 MW plant cases, is installation of a PJFF expected to be economically beneficial. Up to 90 percent mercury control may be achieved at costs less than 1.0 mills/kWh.

Boilers firing low-sulfur bituminous coals and utilizing HS-ESP (model plants I, R). As shown in Table 13, due to the low mercury removal, 25.5 percent, possible from existing equipment in these cases, PAC injection is expected to be necessary for all of the conditions. And, a polishing PJFF must be retrofitted because PAC injection would be added downstream of the HS-ESP and air preheater. As shown in Table 13, 90 percent mercury control may be achieved at costs less than 2.0 mills/kWh.

Boilers firing subbituminous coals (model plants J-L, S-U). Mercury removal with existing equipment is typically lower for subbituminous coals than for bituminous coals. As a result, mercury reduction is more dependent on PAC injection for high levels of mercury removal. In the case of boilers currently equipped with ESP's, it may not be possible to achieve 80 or 90 percent reduction without addition of a downstream PJFF. As shown in Table 14, for model plant J and S cases without a downstream PJFF, estimates for 80 or 90 percent mercury reduction show high costs due to high predicted injection rates. It is recognized that despite the high injection rates the specified Hg reduction may not be achievable without addition of a PJFF after the ESP. However, it should be noted that the algorithms used for PAC injection here (Equation 10 and the associated constants for this case) were developed from the test results at the Pleasant Prairie Power Plant, which used a coal with a coal chlorine content of only 15 ppm, which is lower than typically expected for this type of fuel.[16] So, it is possible that other PRB fueled boilers may be easier to control with PAC than what is shown here. In any case, the results in Table 14 reflect that up to 90 percent mercury control may be achieved at costs less than 2.0 mills/kWh.

For mercury reduction from boilers firing subbituminous coals and equipped with a downstream FF (model plants K and T), PAC injection is necessary for greater than about 60 percent mercury reduction (see Table 15). Addition of a downstream PJFF provides the benefit of much lower waste disposal costs because fly ash is not contaminated. As shown in Table 15, the additional cost of waste disposal roughly compensates for the cost of the PJFF for the 975 MW case. The results reflect that up to 90 percent mercury control may be achieved at costs less than 2.0 mills/kWh.

Finally, at plants with HS-ESPs (model plants L and U), it is necessary to install a downstream PJFF for mercury removal by PAC injection. As shown in Table 16, up to 90 percent mercury control may be achieved at costs below 2 mills/kWh.

SUMMARY

There are two broad approaches to controlling mercury emissions from coal-fired electric utility boilers: (1) powered activated carbon (PAC) injection, and (2) multipollutant control, in which Hg capture is enhanced in existing or new sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) control devices. In 2000, estimates of performance levels and associated costs for control technology applications based on the above approaches were developed. This work presents updated estimates based on results from recent field tests. In particular, updated cost and performance estimates were developed to help inform the Utility Maximum Achievable Control Technology (MACT) rulemaking proposal. Since mercury control approaches at present are developmental in nature, cost and performance estimates are preliminary. These estimates are expected to be refined as mercury control technologies are matured to commercial status.

In general, costs are comprised of capital and operating cost components. The capital costs of PAC injection-based technologies comprise a relatively minor fraction of the total annual costs, the major fraction is associated with the costs related to the use of PAC. Therefore, for such technologies, cost assessments are based on total annual costs. These costs include annualized capital charge, annual fixed O&M costs, and annual variable O&M costs. In this work, each of these cost components are assessed to develop total annual cost (mills/kWh) for each technology application.

Model plants were used for estimating the performance and costs of mercury controls. Approximately 75% of the existing coal-fired utility boilers in the U.S. are equipped with ESPs for controlling PM emissions. The remaining boilers employ FFs, PS, or other equipment for controlling PM. Additionally, units firing medium-to-high sulfur coals may use FGD technologies to meet their SO_2 control requirements. Generally, larger units firing high sulfur coals employ wet FGD, while smaller units may use SDs. Again larger boilers may use SCR for NO_X control. While developing model plant configurations, EPA took these PM, SO_2, and NO_X control possibilities into account. Further, mercury removal in these controls was estimated using correlations developed from statistical analyses of Information Collection Request data.

Table 17 shows preliminary costs for mercury controls for coal-fired boilers. Listed are control costs for at least 80 percent and up to 90 percent reduction. Further, the calculations performed to generate the results in this table conservatively assumed that all collected fly ash is currently sold. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 0.37 mills/kWh for the low sulfur bituminous coal and around 1.01 mills/kWh for the low sulfur bituminous coal. In many cases these disposal costs may not apply because landfilling of ash may be in practice prior to application of PAC injection or because ash may not be rendered completely unacceptable for re-use.

As seen in Table 17, preliminary estimates of cost for PAC injection applications range from 0.003-3.096 mills/kWh. In general, the higher costs are associated with the plants using SDs and

CS-ESPs, or the plants using HS-ESPs, which represent a minority of power plants. Excluding the plants using SDs plus CS-ESPs or HS-ESPs, the cost estimates range from 0.003 to 1.903 mills/kWh. In arriving at these costs, it was assumed that for situations where one approach seemed to be more attractive than another [e.g., PAC injection alone versus PAC injection plus a pulse-jet fabric filter (PJFF)], the facility owner would normally select the more economically attractive approach.

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**[a]	**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	SD+CS-ESP	not tested	35 %	not tested
	SD+FF	98 %	24 %	0 %
	SD+FF+SCR	98 %	not tested	not tested
PM control and wet FGD system[b]	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

[a] CS-ESP = cold-side electrostatic precipitator, HS-ESP = hot-side electrostatic precipitator, FF = fabric filter, PS = particle scrubber, SD = spray dryer

[b] Estimated capture across both control devices

Table 2. Parameters used for equations 1 and 2, which estimate mercury removal by existing equipment (from Ref. 15).

Existing Equipment	**C1**	**C2**	**Min**	**Max**
CS-ESP	0.1233	-0.3885	0.0%	55.0%
CS-ESP + wet FGD	0.1157	-0.1438	24.0%	70.0%
HS-ESP	0.0927	-0.4024	0.0%	27.0%
HS-ESP + wet FGD	0.2845	-1.3236	4.0%	65.0%
FBC[a] + FF	0.1394	0.1127	66.0%	99.0%
FF	0.1816	-0.4287	40.0%	85.0%
FF + wet FGD	0.1943	-0.2385	79.0%	96.0%
SD + CS-ESP	-0.1087	0.6932	5.0%	25.0%
SD + FF	0.2854	-1.1302	0.0%	99.0%

[a] FBC = fluidized bed combustor

Table 3. Values of constants used in the PAC injection Eq. 10.

Case	Retrofit PJFF	A	B	C	D (%)
High-sulfur bit., CS-ESP + wet FGD	No	300	1.5	0.8	109
High-sulfur bit., CS-ESP + wet FGD	Yes	53	0.1	2.0	100
High-sulfur bit., FF + wet FGD	No	53	0.1	2.0	100
High-sulfur bit., HS-ESP + wet FGD	Yes	53	0.1	2.0	100
High-sulfur bit., SD + CSESP	No	300	1.5	0.8	109
High-sulfur bit., SD + CSESP	Yes	53	0.1	2.0	100
High-sulfur bit., SD + CSESP	Yes	300	1.5	0.8	109
Low-sulfur bit., CS-ESP	No	300	1.5	0.8	109
Low-sulfur bit., CS-ESP	Yes	53	0.1	2.0	100
Low-sulfur bit., FF	No	53	0.1	2.0	100
Low-sulfur bit., FF	Yes	53	0.1	2.0	100
Low-sulfur bit., HS-ESP	Yes	53	0.1	2.0	100
Subbit., CS-ESP	No	145	3.5	1.05	70.1
Subbit., CS-ESP	Yes	160	1.0	2.0	100
Subbit., FF	No	160	1.0	2.0	100
Subbit., FF	Yes	160	1.0	2.0	100
Subbit., HS-ESP	Yes	160	1.0	2.0	100

Table 4. Model plants used to develop costs of mercury controls.

Model Plant	**Size (MW)**	**Coal**		**Existing Controls**	**Additional Control[b]**	**Co-benefit case(s) with**
		Type[a]	**%S**			
A	975	Bit	3	CS-ESP + FGD	PAC or PAC+PJFF	SCR
B	975	Bit	3	FF + FGD	PAC	SCR
C	975	Bit	3	HS-ESP + FGD	PAC+PJFF	SCR
D	300	Bit	3	ESP + FGD	PAC or PAC+PJFF	SCR
E	300	Bit	3	FF + FGD	PAC,	SCR
F	300	Bit	3	HS-ESP + FGD	PAC+PJFF	SCR
G	975	Bit	0.6	CS-ESP	PAC or PAC+PJFF	
H	975	Bit	0.6	FF	PAC or PAC+PJFF	
I	975	Bit	0.6	HS-ESP	PAC+PJFF	
J	975	Subbit	0.5	CS-ESP	PAC or PAC+PJFF	
K	975	Subbit	0.5	FF	PAC or PAC+PJFF	
L	975	Subbit	0.5	HS-ESP	PAC+PJFF	
M	100	Bit	3	SD + CS-ESP	PAC or PAC+PJFF	
N	100	Bit	3	SD + FF	PAC	
O	100	Bit	3	HS-ESP + FGD	PAC+PJFF	
P	100	Bit	0.6	CS-ESP	PAC or PAC+PJFF	
Q	100	Bit	0.6	FF	PAC or PAC+PJFF	
R	100	Bit	0.6	HS-ESP	PAC+PJFF	
S	100	Subbit	0.5	CS-ESP	PAC or PAC+PJFF	
T	100	Subbit	0.5	FF	PAC or PAC+PJFF	
U	100	Subbit	0.5	HS-ESP	PAC+PJFF	

[a] Bit = bituminous coal, Subbit = subbituminous coal

[b] PJFF = pulse jet fabric filter

Table 5. Characteristics of power plants used in this work.

MW Equivalent of Flue Gas to Control System	MW	100, 300, 500, 975
Net Plant Heat Rate	Btu/kWh	10,500
Plant Capacity Factor	%	65
Total Air Downstream of Economizer	%	120
Air Heater Leakage	%	12
Air Heater Outlet Gas Temperature	°F	300
Inlet Air Temperature	°F	80
Ambient Absolute Pressure	In. of Hg	29.4
Pressure After Air Heater	In. of H_2O	-12
Moisture in Air	lb/lb dry air	0.013
Ash Split:		
Fly Ash	%	80
Bottom Ash	%	20
Seismic Zone	Integer	1

Table 6. Fuels used in this work.

Coal Type		**High Sulfur Bituminous**	**Low Sulfur Bituminous**	**PRB Subbituminous**
PROXIMATE ANALYSIS (ASTM, received)				
Volatile Matter	wt%	40.40	44.00	30.79
Fixed Carbon	wt%	47.50	50.00	32.41
Moisture	wt%	3.10	2.20	30.40
Ash	wt%	9.00	3.80	6.40
		100.00	100.00	100.00
COAL ULTIMATE ANALYSIS (ASTM, as received)				
Moisture	wt%	3.10	2.20	30.40
Carbon	wt%	69.82	78.48	47.85
Hydrogen	wt%	5.00	5.50	3.40
Nitrogen	wt%	1.26	1.30	0.62
Chlorine	wt%	0.12	0.12	0.03
Sulfur	wt%	3.00	0.60	0.48
Ash	wt%	9.00	3.80	6.40
Oxygen	wt%	8.70	8.00	10.82
TOTAL	wt%	100.00	100.00	100.00
Mercury	mg/kg	0.10	0.10	0.07
Modified Mott Spooner HHV (Btu/lb)	Btu/lb	12,676	14,175	8,304
COAL ASH ANALYSIS (ASTM, as received)				
SiO_2	wt%	29.00	51.00	31.60
Al_2O_3	wt%	17.00	30.00	15.30
TiO_2	wt%	0.74	1.50	1.10
Fe_2O_3	wt%	36.00	5.60	4.60
CaO	wt%	6.50	4.20	22.80
MgO	wt%	0.83	0.76	4.70
Na_2O	wt%	0.20	1.40	1.30
K_2O	wt%	1.20	0.40	0.40
P_2O_5	wt%	0.22	1.80	0.80
SO_3	wt%	7.30	2.60	16.60
Other Unaccounted for	wt%	1.01	0.74	0.80
TOTAL	wt%	100.00	100.00	100.00

Table 7a. High Sulfur Coal, CS-ESP plus FGD without SCR Co-benefit (Model Plants A, D).

Specified Hg reduction		**50%**	**60%**	**70%**	**80%**	**90%**
Hg reduction of existing equipment		67.7%	67.7%	67.7%	67.7%	67.7%
Hg reduction by PAC		none	none	7.3%	38.2%	69.1%
975 MW						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.094	$0.094	$1.601	$2.437	$4.304
Variable Cost	mills/kWh	0.000	0.000	1.195	1.447	2.175
Total Cost	mills/kWh	0.003	0.003	1.242	1.520	2.303
Retrofit PJFF?		no	no	yes	yes	yes
Capital Cost	$/kW	$0.094	$0.094	$36.216	$36.322	$36.538
Variable Cost	mills/kWh	0.000	0.000	0.215	0.234	0.278
Total Cost	mills/kWh	0.003	0.003	1.122	1.144	1.195
300 MW						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.126	$0.126	$2.370	$3.600	$6.330
Variable Cost	mills/kWh	0.000	0.000	1.195	1.447	2.175
Total Cost	mills/kWh	0.004	0.004	1.265	1.554	2.363
Retrofit PJFF?		no	no	yes	yes	yes
Capital Cost	$/kW	$0.126	$0.126	$45.989	$46.147	$46.467
Variable Cost	mills/kWh	0.000	0.000	0.215	0.234	0.278
Total Cost	mills/kWh	0.004	0.004	1.352	1.376	1.430

Table 7b. High Sulfur Coal, CS-ESP plus FGD with SCR Co-benefit (Model Plants A, D).

Specified Hg reduction		**50%**	**60%**	**70%**	**80%**	**90%**
Hg reduction of existing equipment		90%	90%	90%	90%	90%
Hg reduction by PAC		none	none	none	none	none
975 MW						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.094	$0.094	$0.094	$0.094	$0.094
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.000
Total Cost	mills/kWh	0.003	0.003	0.003	0.003	0.003
300 MW						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.126	$0.126	$0.126	$0.126	$0.126
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.000
Total Cost	mills/kWh	0.004	0.004	0.004	0.004	0.004

Table 8a. High Sulfur Coal, HS-ESP plus FGD without SCR Co-benefit (Model Plants C, F, O).

Specified Hg reduction		**50%**	**60%**	**70%**	**80%**	**90%**
Hg reduction of existing equipment		65.0%	65.0%	65.0%	65.0%	65.0%
Hg reduction by PAC		none	none	14.3%	42.9%	71.4%
975 MW						
PAC, Including additional PJFF and CEMS						
Retrofit PJFF?		no	no	yes	yes	yes
Capital Cost	$/kW	$0.094	$0.094	$36.236	$36.345	$36.566
Variable Cost	mills/kWh	0.000	0.000	0.218	0.239	0.284
Total Cost	mills/kWh	0.003	0.003	1.126	1.149	1.201
300 MW						
PAC, Including additional PJFF and CEMS						
Retrofit PJFF?		no	no	yes	yes	yes
Capital Cost	$/kW	$0.126	$0.126	$46.018	$46.180	$46.508
Variable Cost	mills/kWh	0.000	0.000	0.218	0.239	0.284
Total Cost	mills/kWh	0.004	0.004	1.357	1.382	1.437
100 MW						
PAC, Including additional PJFF and CEMS						
Retrofit PJFF?		no	no	yes	yes	yes
Capital Cost	$/kW	$0.165	$0.165	$57.533	$57.767	$58.241
Variable Cost	mills/kWh	0.000	0.000	0.217	0.237	0.282
Total Cost	mills/kWh	0.005	0.005	1.627	1.654	1.714

Table 8b. High Sulfur Coal, HS-ESP plus FGD with SCR Co-benefit (Model Plants C, F).

Specified Hg reduction		**50%**	**60%**	**70%**	**80%**	**90%**
Hg reduction of existing equipment		90%	90%	90%	90%	90%
Hg reduction by PAC		none	none	none	none	none
975 MW						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.094	$0.094	$0.094	$0.094	$0.094
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.000
Total Cost	mills/kWh	0.003	0.003	0.003	0.003	0.003
300 MW						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.126	$0.126	$0.126	$0.126	$0.126
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.000
Total Cost	mills/kWh	0.004	0.004	0.004	0.004	0.004

Table 9. 100 MW SD and CS-ESP (Model Plant M).

Specified Hg reduction		**50%**	**60%**	**70%**	**80%**	**90%**
Hg reduction of existing equipment		5.0%	5.0%	5.0%	5.0%	5.0%
Hg reduction by PAC		47.4%	57.9%	68.4%	78.9%	89.5%
100 MW No PJFF						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$6.014	$7.235	$8.996	$11.818	$17.266
Variable Cost	mills/kWh	0.659	0.877	1.226	1.861	3.309
Total Cost	mills/kWh	0.838	1.092	1.493	2.211	3.821
100 MW and full size PJFF						
Retrofit PJFF?		yes	yes	yes	yes	yes
Capital Cost	$/kW	$110.342	$110.891	$111.094	$111.413	$112.065
Variable Cost	mills/kWh	0.242	0.255	0.275	0.308	0.383
Total Cost	mills/kWh	2.907	2.934	2.960	3.002	3.096
With PJFF (COHPAC Conversion)						
Retrofit PJFF?		yes	yes	yes	yes	yes
Capital Cost	$/kW	$57.612	$57.970	$58.174	$58.495	$59.149
Variable Cost	mills/kWh	0.243	0.257	0.277	0.310	0.385
Total Cost	mills/kWh	1.657	1.680	1.706	1.749	1.843

Table 10. 100 MW SD and FF (Model Plant N).

Specified Hg reduction		50%	60%	70%	80%	90%
Hg reduction of existing equipment		89.3%	89.3%	89.3%	89.3%	89.3%
Hg reduction by PAC		none	none	none	none	6.3%
No PJFF						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.165	$0.165	$0.165	$0.165	$3.388
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.270
Total Cost	mills/kWh	0.005	0.005	0.005	0.005	0.370

Table 11. With CS-ESP and no SO_2 Controls (Model Plants G and P).

Specified Hg reduction		50%	60%	70%	80%	90%
Hg reduction of existing equipment		50.6%	50.6%	50.6%	50.6%	50.6%
Hg reduction by PAC		none	19.0%	39.2%	59.5%	79.7%
975 MW No PJFF						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.094	$1.855	$2.467	$3.490	$5.711
Variable Cost	mills/kWh	0.000	0.709	0.901	1.277	2.282
Total Cost	mills/kWh	0.003	0.764	0.974	1.381	2.451
975 MW With PJFF						
Retrofit PJFF?		no	yes	yes	yes	yes
Capital Cost	$/kW	$0.094	$36.248	$36.324	$36.445	$36.690
Variable Cost	mills/kWh	0.000	0.220	0.234	0.258	0.311
Total Cost	mills/kWh	0.003	1.128	1.144	1.171	1.233
100 MW No PJFF						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.165	$3.971	$5.271	$7.430	$12.057
Variable Cost	mills/kWh	0.000	0.709	0.901	1.277	2.282
Total Cost	mills/kWh	0.005	0.827	1.057	1.497	2.639
100 MW With PJFF						
Retrofit PJFF?		no	yes	yes	yes	yes
Capital Cost	$/kW	$0.165	$57.563	$57.729	$57.989	$58.518
Variable Cost	mills/kWh	0.000	0.220	0.234	0.258	0.311
Total Cost	mills/kWh	0.005	1.631	1.650	1.682	1.751

Table 12. FF and no SO_2 Controls (Model Plants H and Q).

Specified Hg reduction		**50%**	**60%**	**70%**	**80%**	**90%**
Hg reduction of existing equipment		85.0%	85.0%	85.0%	85.0%	85.0%
Hg reduction by PAC		none	none	none	none	33.3%
975 MW No PJFF						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.094	$0.094	$0.094	$0.094	$0.821
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.458
Total Cost	mills/kWh	0.003	0.003	0.003	0.003	0.482
975 MW With PJFF						
Retrofit PJFF?		no	no	no	no	yes
Capital Cost	$/kW	$0.094	$0.094	$0.094	$0.094	$36.299
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.229
Total Cost	mills/kWh	0.003	0.003	0.003	0.003	1.139
100 MW No PJFF						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.165	$0.165	$0.165	$0.165	$1.752
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.458
Total Cost	mills/kWh	0.005	0.005	0.005	0.005	0.510
100 MW With PJFF						
Retrofit PJFF?		no	no	no	no	yes
Capital Cost	$/kW	$0.165	$0.165	$0.165	$0.165	$57.674
Variable Cost	mills/kWh	0.000	0.000	0.000	0.000	0.229
Total Cost	mills/kWh	0.005	0.005	0.005	0.005	1.644

Table 13. With HS-ESP and no SO_2 Controls (Model Plants I and R).

Specified Hg reduction		**50%**	**60%**	**70%**	**80%**	**90%**
Hg reduction of existing equipment		25.5%	25.5%	25.5%	25.5%	25.5%
Hg reduction by PAC		32.9%	46.3%	59.7%	73.2%	86.6%
975 MW With PJFF						
Retrofit PJFF?		yes	yes	yes	yes	yes
Capital Cost	$/kW	$36.162	$36.360	$36.447	$36.584	$36.865
Variable Cost	mills/kWh	0.229	0.241	0.258	0.287	0.353
Total Cost	mills/kWh	1.135	1.152	1.172	1.205	1.280
100 MW With PJFF						
Retrofit PJFF?		yes	yes	yes	yes	yes
Capital Cost	$/kW	$57.458	$57.805	$57.994	$58.290	$58.893
Variable Cost	mills/kWh	0.229	0.241	0.258	0.287	0.353
Total Cost	mills/kWh	1.638	1.659	1.682	1.720	1.804

Table 14. CS-ESP and no SO_2 Control (Model Plants J, S).

Specified Hg reduction		**50%**	**60%**	**70%**	**80%**	**90%**
Hg reduction of existing equipment		29.7%	29.7%	29.7%	29.7%	29.7%
Desired Hg reduction by PAC		28.9%	43.1%	57.3%	71.5%	85.8%
Actual Hg reduction by PAC without PJFF*		28.9%	43.1%	57.3%	69.3%	69.3%
Total Actual Hg Reduction without PJFF*		50.0%	60.0%	70.0%	78.5%	78.5%
975 MW with cold- side ESP, No PJFF*						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.401	$1.238	$3.232	$27.744	$27.744
Variable Cost	mills/kWh	1.027	1.181	1.811	20.102	20.102
Total Cost	mills/kWh	1.039	1.218	1.907	20.924	20.924
975 MW with cold- side ESP, PJFF						
Retrofit PJFF?		yes	yes	yes	yes	yes
Capital Cost	$/kW	$35.998	$36.258	$36.422	$36.666	$37.139
Variable Cost	mills/kWh	0.209	0.231	0.262	0.315	0.435
Total Cost	mills/kWh	1.111	1.139	1.176	1.236	1.369
100 MW with cold- side ESP, No PJFF*						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.840	$2.651	$6.887	$55.806	$55.806
Variable Cost	mills/kWh	1.027	1.181	1.811	20.102	20.102
Total Cost	mills/kWh	1.052	1.259	2.015	21.756	21.756
100 MW with cold- side ESP, PJFF						
Retrofit PJFF?		yes	yes	yes	yes	yes
Capital Cost	$/kW	$57.102	$57.585	$57.939	$58.466	$59.479
Variable Cost	mills/kWh	0.209	0.231	0.262	0.315	0.435
Total Cost	mills/kWh	1.608	1.643	1.685	1.753	1.903

*Based on the PAC injection algorithm used in this work, for subbituminous coals without a downstream fabric filter, Hg reduction at levels more than 70 percent may not be possible without a polishing PJFF.

Table 15. FF and no SO_2 Control (Model Plants K, T).

Specified Hg reduction		50%	60%	70%	80%	90%
Hg reduction of existing equipment		60.7%	60.7%	60.7%	60.7%	60.7%
Hg reduction by PAC		none	none	23.6%	49.1%	74.5%
975 MW with FF, No PJFF						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.094	$0.094	$0.616	$0.842	$1.259
Variable Cost	mills/kWh	0.000	0.000	1.057	1.097	1.186
Total Cost	mills/kWh	0.003	0.003	1.075	1.122	1.223
975 MW with FF, PJFF						
Retrofit PJFF?		no	no	yes	yes	yes
Capital Cost	$/kW	$0.094	$0.094	$36.094	$36.320	$36.737
Variable Cost	mills/kWh	0.000	0.000	0.203	0.243	0.332
Total Cost	mills/kWh	0.003	0.003	1.106	1.153	1.254
100 MW with FF, No PJFF						
Retrofit PJFF?		no	no	no	no	no
Capital Cost	$/kW	$0.165	$0.165	$1.308	$1.799	$2.696
Variable Cost	mills/kWh	0.000	0.000	1.057	1.097	1.186
Total Cost	mills/kWh	0.005	0.005	1.096	1.150	1.266
100 MW with FF, PJFF						
Retrofit PJFF?		no	no	yes	yes	yes
Capital Cost	$/kW	$0.165	$0.165	$57.230	$57.721	$58.618
Variable Cost	mills/kWh	0.000	0.000	0.203	0.243	0.332
Total Cost	mills/kWh	0.005	0.005	1.604	1.659	1.774

Table 16. HS-ESP and no SO_2 Controls (Model Plants L, U).

Specified Hg reduction		50%	60%	70%	80%	90%
Hg reduction of existing equipment		12.6%	12.6%	12.6%	12.6%	12.6%
Hg reduction by PAC		42.8%	54.2%	65.7%	77.1%	88.6%
975 MW with CS-ESP, PJFF						
Retrofit PJFF?		yes	yes	yes	yes	yes
Capital Cost	$/kW	$36.119	$36.381	$36.550	$36.806	$37.305
Variable Cost	mills/kWh	0.230	0.254	0.289	0.348	0.482
Total Cost	mills/kWh	1.135	1.166	1.206	1.273	1.421
100 MW with CS-ESP, PJFF						
Retrofit PJFF?		yes	yes	yes	yes	yes
Capital Cost	$/kW	$57.365	$57.852	$58.217	$58.766	$59.834
Variable Cost	mills/kWh	0.230	0.254	0.289	0.348	0.482
Total Cost	mills/kWh	1.637	1.674	1.720	1.795	1.960

Table 17. Preliminary estimates of costs (2003 constant dollars) of mercury controls to achieve between 80 and 90 percent reduction of mercury across existing and, if needed, additional controls.

Coal		**Boiler Size Range (MW)**	**Existing Control Configuration[b]**	**Additional Controls[c]**	**Cost Estimates of Additional Controls, (mills/kWh)**
Type[a]	S%				
Bit	3	975-300	CS-ESP + wet FGD	PAC + PJFF + CEMS PAC + CEMS	1.144-1.430
Bit	3	975-300	SCR + CS-ESP + wet FGD	CEMS	0.003-0.04[d]
Bit	3	975-300	FF + wet FGD	CEMS	0.003-0.04[e]
Bit	3	975-300	SCR + FF + wet FGD	CEMS	0.003-0.04[f]
Bit	3	975-300	HS-ESP + wet FGD	PAC + PJFF + CEMS	1.149-1.437
Bit	3	100	SD + CS-ESP	PAC + PJFF + CEMS	1.749-3.096[g]
Bit	3	100	SD + FF	PAC + CEMS	0.005-0.370[h]
Bit	0.6	975-100	CS-ESP	PAC + PJFF + CEMS	1.171-1.751
Bit	0.6	975-100	FF	PAC + CEMS	0.003-0.510[i]
Bit	0.6	975-100	HS-ESP	PAC + PJFF + CEMS	1.205-1.804
PRB	0.5	975-100	CS-ESP	PAC + PJFF + CEMS	1.236-1.903
PRB	0.5	975-100	FF	PAC + CEMS	1.122-1.266
PRB	0.5	975-100	HS-ESP	PAC + PJFF + CEMS	1.273-1.960

[a] Bit. = bituminous coal, PRB = powder river basin coal.
[b] CS-ESP = cold-side electrostatic precipitator, HS-ESP = hot-side electrostatic precipitator, FF = fabric filter, PS = particle scrubber, SD = spray dryer, SCR = selective catalytic reduction.
[c] PAC = powered activated carbon, CEMS = continuous emissions monitoring system, PJFF = pulse jet fabric filter.
[d] Existing equipment removes 90% of mercury because SCR enhances mercury removal in wet FGD. Therefore costs are for mercury monitoring (CEMs) only.
[e] Existing equipment removes 96% of mercury. Therefore costs are for mercury monitoring (CEMS) only.
[f] Effect of SCR is not significant because existing equipment removes 96% of mercury. Costs are for mercury monitoring (CEMs) only.
[g] For 80% control, assumes no PJFF. For 90% control, assumes full-size PJFF sized for full ash loading and more expensive than if sized for downstream of an CS-ESP or FF.
[h] Existing equipment removes 89% of mercury so a small amount of PAC is needed for 90% control.
[i] Existing equipment removes 85% of mercury so a small amount of PAC is needed for 90% control.

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