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PERFORMANCE AND COST OF
MERCURY EMISSION CONTROL
TECHNOLOGY APPLICATIONS ON
ELECTRIC UTILITY BOILERS

Prepared for

Office of Air and Radiation

Prepared by

National Risk Management
Research Laboratory
Research Triangle Park, NC 27711

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Performance and Cost of Mercury Emission Control Technology Applications on Electric Utility Boilers

Prepared by:

Ravi K. Srivastava, Charles B. Sedman, and James D. Kilgroe
U.S. Environmental Protection Agency
Office of Research and Development
National Risk Management Research Laboratory
Research Triangle Park, NC 27711

ABSTRACT

Under the Clean Air Act Amendments of 1990, the Environmental Protection Agency (EPA) has to determine whether mercury emissions from coal-fired power plants should be regulated. To aid in this determination, estimates of the performance and cost of powdered activated carbon (PAC) injection-based mercury control technologies have been developed. This report presents these estimates and develops projections of costs for future applications.

Estimates based on currently available data using PAC range from 0.305 to 3.783 mills/kWh. However, the higher costs are associated with the minority of plants using hot-side electrostatic precipitators (HESPs). If these costs are excluded, the estimates range from 0.305 to 1.915 mills/kWh. Cost projections, developed based on using a composite lime-PAC sorbent for mercury removal, range from 0.183 to 2.270 mills/kWh with the higher costs being associated with the minority of plants using HESPs.

A comparison of mercury control costs with those of nitrogen oxides (NO_x) controls reveals that total annual costs for mercury controls lie mostly between applicable costs for low NO_x burners (LNBs) and selective catalytic reduction (SCR). As mentioned above, estimates of total annual cost are higher for cases that are applicable to the minority of plants using HESPs. Excluding these costs, both currently estimated and projected mercury control costs are in the spectrum of LNB and SCR costs.

The performance and cost estimates of the PAC injection-based mercury control technologies presented in this report are based on relatively few data points from pilot-scale tests and, therefore, are considered to be preliminary. Factors that are known to affect the adsorption of mercury on PAC or other sorbent include the speciation of mercury in flue gas, the effect of flue gas and ash characteristics, and the degree of mixing between flue gas and sorbent. This mixing may be especially important where sorbent has to be injected in relatively large ducts. The effect of these factors may not be entirely accounted for in the relatively few pilot-scale data points that comprised the basis for this work. Ongoing research is expected to address these issues and to improve the cost effectiveness of using sorbents for mercury control. Further research is also needed on ash and sorbent residue to evaluate mercury retention and the potential for release back into the environment.

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List of Acronyms and Abbreviations

ADP	Acid Dew Point
CAAA	Clean Air Act Amendments of 1990
EPA	United States Environmental Protection Agency
ESP	Electrostatic Precipitator
FF	Fabric Filter
FGD	Flue Gas Desulfurization
HCl	Hydrogen Chloride
HESP	Hot-side Electrostatic Precipitator
Hg	Mercury
$HgCl_2$	Mercuric Chloride
Hg^0	Elemental Mercury
Hg^{++}	Ionic Mercury
HgO	Mercury Oxide
$HgSO_4$	Mercury Sulfate
ICR	Information Collection Request
IPM	Integrated Planning Model
kWh	Kilowatt Hour
LNB	Low NO_x Burner
MW	Megawatt
MWCs	Municipal Waste Combustors
NETL	National Energy Technology Laboratory
NO_x	Nitrogen Oxides
OAR	EPA's Office of Air and Radiation
O&M	Operation and Maintenance
PAC	Powdered Activated Carbon
PFF	Polishing Fabric Filter
PM	Particulate Matter
R&D	Research and Development
SC	Spray Cooling
SCR	Selective Catalytic Reduction
SD	Spray Dryer

SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide

1.0 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^{++}). Hg^0 can circulate in the atmosphere for up to 1 year and, consequently, can undergo dispersion over regional and global scales. Hg^{++} in the atmosphere either is 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 redeposited 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. Adults exposed to methylmercury show symptoms of tremors, loss of coordination, and memory and sensory difficulties. Offspring exposed during pregnancy show atrophy of the brain with delayed mental development. The incidence and extent of such effects depend on the level of exposure to methylmercury. Hg^0 is readily absorbed through lungs and, being fat-soluble, is rapidly distributed throughout the body. Subsequently, it slowly oxidizes to Hg^{++}, which accumulates in the brain and can lead to tremors, memory disturbances, sensory loss, and personality changes. Hg^{++} is absorbed through the digestive tract, accumulates in the kidneys, and can lead to immune-mediated kidney toxicity. 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.[1] A severe case of human exposure occurred in Minamata, Japan in the 1950s.[2]

Under the Clean Air Act Amendments of 1990, the Environmental Protection Agency (EPA) has to determine whether mercury emissions from coal-fired power plants should be regulated.[3] To aid in this determination, this report presents preliminary estimates of the performance and cost of promising mercury control technologies applicable to coal-fired electric utility boilers. As explained later in this report, most of these technologies are based on injection of powdered activated carbon (PAC) into boiler flue gas.

The report layout is as follows. First, promising mercury control technologies for coal-fired electric utility boilers are identified. Second, performance characteristics of these technologies are estimated. These include characterization of mercury removal performance possible as a function of PAC injection rate. Third, model plants representing the spectrum of retrofit possibilities are identified. Next, costs of controlling mercury emissions from these model plants are examined. Finally, potential future improvements in these costs are discussed. During discussion of cost and potential improvements, research and development (R&D) areas are identified for near-term emphasis.

The performance and cost estimates of the PAC injection-based mercury control technologies presented in this report are based on relatively few data points from pilot-scale tests and, therefore, are considered to be preliminary. Factors that are known to affect the adsorption of mercury on PAC or other sorbent include the speciation of mercury in flue gas, the effect of flue gas and ash characteristics, and the degree of mixing between flue gas and sorbent. This mixing may be especially important where sorbent has to be injected in relatively large ducts. The effect of these factors may not be entirely accounted for in the relatively few pilot-scale data points that comprised the basis for this work. Ongoing research is expected to address these issues and to improve the cost effectiveness of using sorbents for mercury control.

Use of sorbent injection technologies to control mercury emissions from electric power plants would result in mercury-impregnated sorbent waste, which would need to be disposed off either by itself or in mixture with flyash. One of the more commonly practiced solid waste disposal options is landfilling. However, information is not currently available on the stability of mercury in ash and sorbent residue. Therefore, it is unclear whether any potential exists for the release of mercury back into the environment from landfilled mercury-impregnated solid waste. Further research is needed on ash and sorbent residue to evaluate mercury retention and the potential for release back into the environment. Due to lack of information, this report does not address any potential costs that may result if mercury has to be stabilized in sorbent waste.

2.0 MERCURY SPECIATION AND CAPTURE

Mercury is volatilized and converted to Hg^0 in the high temperature regions of combustion devices. As the flue gas cools, Hg^0 is oxidized to Hg^{++}. The rate of oxidization is dependent on the temperature, flue gas composition and properties, and amount of flyash and any entrained sorbents. In coal-fired combustors, where the concentrations of hydrogen chloride (HCl) are low, and where equilibrium conditions are not achieved, Hg^0 may be oxidized to mercuric oxide (HgO), mercuric sulfate ($HgSO_4$), mercuric chloride ($HgCl_2$), or some other mercury compound.[4] The oxidization of Hg^0 to $HgCl_2$ and to other ionic forms of mercury is abetted by catalytic reactions on the surface of flyash or sorbents and by other compounds that may be present in the flue gas. Consequently, applications of nitrogen oxides (NO_x) control technologies such as selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) may assist in oxidation of Hg^0.

Hg^0, $HgCl_2$, and HgO are primarily in the vapor phase at flue gas cleaning temperatures. Therefore, each of these forms of mercury can potentially be adsorbed onto porous solids such as flyash, PAC, and calcium-based acid gas sorbents for subsequent collection in a particulate matter (PM) control device. These mercury forms may also be captured in carbon bed filters or other reactors containing appropriate sorbents.

Mercury removal with wet scrubbers also appears to be possible. $HgCl_2$ is water-soluble and reacts readily with alkali metal oxides in an acid-base reaction; therefore, conventional acid gas scrubbers used for sulfur dioxide (SO_2) control can also effectively capture $HgCl_2$. The total mercury removal efficiency of wet scrubbers has been reported to range from 30 to 90%.[5] However, Hg^0 is insoluble in water and must be adsorbed onto a sorbent, or converted to a soluble form of mercury that can be collected by wet scrubbing. HgO has low solubility and probably has to be collected by methods similar to those used for Hg^0.

3.0 MERCURY CONTROL TECHNOLOGY APPLICATIONS

Based on published literature,[1, 5-9] control technologies using injection of PAC into the flue gas appear to hold promise for reducing mercury emissions from utility boilers. These technologies have been applied successfully on municipal waste combustors (MWCs). Also, pilot-scale tests indicate that these technologies may be able to provide significant mercury removal from the flue gas of coal-fired utility boilers. Accordingly, this evaluation focused on characterization of performance and total annual cost of PAC injection-based technologies.

This section describes PAC injection-based control technologies that can be retrofitted to existing boilers for control of mercury emissions, PAC injection estimates for these technologies, and model plants used in this work. Subsequently, control technology applications on model plants are used to develop estimates of total annual costs.

3.1 PAC Injection-Based Technologies

Table 1 lists the PAC injection-based technologies evaluated in this work. Pilot-scale applications of most of these technologies have been reported in published literature. The table gives technology names, corresponding components, and existing equipment to which these retrofit technologies are applied. The current understanding is that particle-bound mercury is well collected in PM or SO_2 control systems, Hg^0 is not so well collected, and Hg^{++} is collected to a greater or lesser degree depending on characteristics of the control device and conditions within it. Therefore, for a specified mercury removal requirement, the rate of PAC injection needed will depend, in part, on the ability of existing controls to remove the three species of mercury.

In ESP-1, PAC is injected between the air preheater and the cold-side ESP (i.e., an ESP located downstream of the boiler’s air preheater). This technology is relatively simple and lower in capital cost compared to more complex technologies. Activated carbon consumption is expected to be relatively high because the high temperature of the flue gas inhibits adsorption of mercury onto PAC. Increased carbon consumption would lead to higher total annual costs.

In ESP-3, PAC is injected downstream of the cold-side ESP and is collected using a polishing fabric filter (PFF). This technology permits recycling of the PAC sorbent to increase its utilization. Typically, this recycling is achieved by transferring a portion of used sorbent from the PM control device (e.g., PFF) to the sorbent injection location using a chain or a belt conveyor, mixing the used sorbent with fresh sorbent, and injecting the resulting sorbent mixture into the flue gas. Further, the technology provides a contact bed (i.e., filter cake on PFF) for increased adsorption of mercury. Capital and total annual costs are expected to be higher than for ESP-1 because of more equipment and supplies (primarily bags), but carbon cost may be lower.

ESP-4 is similar to ESP-1, but adds spray cooling (SC) upstream of the PAC injection location. Cooling the flue gas aids adsorption and reduces PAC injection requirements. As with ESP-3, capital costs are increased over ESP-1 because of added SC equipment, but total annual costs may be decreased because PAC requirements are significantly reduced. Adding too much water to the flue gas could cause acid condensation, which would tend to corrode ductwork and equipment. For cost modeling, flue-gas temperatures are not allowed to reach the acid dewpoint (ADP).

ESP-6 is similar to ESP-3, but provides SC upstream of PAC injection. Cooling the flue gas aids adsorption and reduces PAC injection requirements. Also, use of PFF permits sorbent recycling, leading to improved sorbent utilization. Capital costs for this configuration are expected to be higher than for most other configurations because of the several pieces of equipment required. Total annual costs would be reduced due to relatively lower carbon consumption, but be increased due to higher maintenance and materials requirements.

Table 1. Mercury control technologies for coal-fired electric utility boilers.

Mercury Control	**Existing Equipment**[a,b]	**Retrofit Technology**[a]
ESP-1	ESP	PAC injection
ESP-3		PAC injection + PFF
ESP-4		SC + PAC injection
ESP-6		SC + PAC injection + PFF
ESP-7		SC + PAC injection + lime injection + PFF
HESP-1	HESP	SC + PAC injection + PFF
FF-1	FF	PAC injection
FF-2		SC + PAC injection
SD/FF-1	SD + FF	PAC injection
SD/ESP-1	SD + ESP	PAC injection

a. ESP = cold-side electrostatic precipitator; HESP = hot-side electrostatic precipitator; FF= fabric filter; SD = spray dryer; PACI = powdered activated carbon; PFF = polishing fabric filter, SC=spray cooling.
b. Existing equipment may include wet scrubber and NO_x controls such as selective catalytic reduction (SCR).

ESP-7 is the same as ESP-6 except for the addition of a second sorbent, lime. In addition to mercury removal, this technology would remove acid gases from the flue gas. Pilot-scale results have indicated that this may result in significant lowering of PAC injection rates. Capital and total annual costs would increase due to addition of the lime system components, but total annual costs would decrease due to lower PAC requirements.

In HESP-1, spray cooling, PAC injection, and a PFF are inserted downstream from a hot-side ESP. This configuration is identical to ESP-6; only the location of the ESP is different. Performance and costs should be similar to those found for ESP-6.

FF-1 is the baghouse analogue of ESP-1. However, mercury collection should be better than that in ESP-1 because the FF provides added residence time and a contact bed (filter cake on the bags) for increased adsorption of mercury. Consequently, PAC injection requirements in an FF-1 application are expected to be lower that those in the corresponding ESP-1 application, thereby resulting in lower total annual costs.

FF-2 is the baghouse analogue of ESP-4; spray cooling and PAC injection are installed upstream of an existing baghouse. As with ESP-4, cooling reduces PAC requirements, which reduces total annual PAC costs for FF-2 compared to FF-1. Capital costs should increase over FF-1 because of the added equipment. Overall total annual costs are increased by water usage and maintenance of the cooling system, but are not expected to increase sufficiently to offset savings from the reduced PAC costs.

In SD/FF-1, PAC is injected into flue gas of a boiler that uses a spray dryer (SD)/FF combination for SO_2 control. In this technology, the spray dryer provides flue gas cooling, so good collection of mercury is expected. Because only PAC injection equipment is added to the existing air pollution control system, capital and total annual costs are expected to be relatively low.

SD/ESP-1, like SD/FF-1, adds PAC injection in an existing SD/ESP combination. The advantages of this technology should be similar to those of SD/FF-1; however, higher amounts of PAC may be needed, relative to SD/FF-1. As such, total annual costs of this technology may be higher than those associated with SD/FF-1.

3.2 PAC Injection Rates

The major factor affecting the cost of PAC injection-based technologies is the rate of PAC injection needed for the required mercury removal efficiency. This rate depends on the temperature of the flue gas and the type of coal fired in the boiler. For this work, PAC injection rates at specific flue gas temperatures and mercury removal efficiencies achieved in pilot-scale tests were fitted to the form of Equation (1) with curve-fit parameters *a*, *b*, and *c* (see Attachment 2 in the Appendix). For each technology for which pilot-scale test data are available, separate correlations of mercury removal efficiency and PAC injection rate were determined for bituminous and subbituminous coals. These coals are predominantly used at utility boilers and, therefore, were chosen for this work.

$$Mercury\ \ Removal\ \ Efficiency\ \ (\%) = 100 - \frac{a}{\left[PAC\ \ Injection\ \ Rate\ \ \left(lb/10^6\, acf\right) + b\right]^{c}} \qquad (1)$$

Equation (1) can be used to calculate the PAC injection rate ($lb/10^6$ acf) needed to achieve specified mercury removal efficiency (%) for the control technology of interest. Note that mercury removal efficiency (%) is based on total[a] mercury removed from the flue gas and is defined as

$$Mercury\ \ Removal\ \ Efficiency\ \ (\%) = 100 \times \frac{\left(Emission_{in} - Emission_{out}\right)}{Emission_{in}} \qquad (2)$$

[a] Total refers to the sum of Hg^0, Hg^{++}, and mercury adsorbed on PM (e.g., flyash).

where:

$Emission_{in}$ = total flue gas mercury concentration at the inlet to the first air pollution control device; and

$Emission_{out}$ = total flue gas mercury concentration at the outlet of the last air pollution control device.

Preliminary analysis of data obtained through EPA's Information Collection Request (ICR)[10] reflected that, at boilers firing bituminous coals and using a cold-side ESP for PM capture, higher levels (more than 50%) of mercury were being removed with flyash than found in earlier pilot-scale tests (see Attachment 2 in the Appendix). Accordingly, for each of technologies ESP-1, ESP-3, ESP-4, and ESP-6, two separate sets of correlations, relating PAC injection rate (lb/10^6 acf) to mercury removal efficiency (%), were created for use with bituminous-coal-fired boilers. The first of these sets, hereafter referred to as the pilot-scale PAC injection rate, was derived using presently available pilot-scale test data. The other set, hereafter referred to as the ICR/pilot-scale PAC injection rate, was derived using preliminary ICR results for flyash capture of mercury (i.e., no PAC injection) and pilot-scale results for PAC injection.

Note that the above data fitting procedure resulted in correlations of PAC injection rate (lb/10^6 acf) versus mercury removal efficiency (%), as a function of flue gas temperature, for most of the technologies except (1) FF-1, FF-2, and SD/FF-1, applied on boilers firing bituminous coals, for which no data are available; (2) HESP-1 applied on boilers firing either bituminous or subbituminous coals, for which no data are available; and (3) ESP-7 and FF-3 applied on boilers firing either bituminous or subbituminous coals, for which pilot-scale data are presently available for ESP-7 application on a boiler firing a bituminous coal.[11] These data reflect that more than 90% of mercury can be removed by injecting relatively small amounts of PAC with lime. Therefore, in this work, application of ESP-7 was evaluated at 90% mercury removal efficiency in a sensitivity analysis.

The algorithms describing sorbent injection rates for various technologies can be found in Attachment 2 in the Appendix.

3.3 Model Plants

Costs for installing and operating the PAC injection-based technologies described above are estimated with model plants. Approximately 75% of the existing coal-fired utility boilers in the U.S. are equipped with electrostatic precipitators (ESPs) for the control of PM.[4] The remaining boilers employ fabric filters (FFs), particulate scrubbers, or other equipment for control of PM. Additionally, units firing medium to high sulfur coals may use flue gas desulfurization (FGD) technologies to meet their SO_2 control requirements. Generally, larger units firing high sulfur coals employ wet FGD, and smaller units firing medium sulfur coals use spray dryers. While developing the model plants, these PM and SO_2 control possibilities were taken into account.

Eighteen model plants with possible flue gas cleaning equipment configurations and firing either bituminous or subbituminous coal were used in this work. Table 2 exhibits these model plants. Note that boiler sizes of 975 and 100 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.[1] It was also envisioned that use of post-combustion NO_x controls such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) may enhance oxidation of mercury in flue gas and result in the "cobenefit" of increased mercury removal in wet FGD. However, at present data on this cobenefit are available for SCR applications only. Since SCR is a capital-intensive technology, generally its use is cost-effective on larger boiler sizes. Accordingly, in this work, the mercury cobenefit resulting from SCR use was evaluated for model plants 1, 2, and 3 utilizing large (975 MW) boilers and wet FGD.

Table 2. Mercury control technology applications and cobenefits.

Model Plant	**Size (MW)**	**Coal**		**Existing Controls**	**Mercury Control(s)[b]**	**Cobenefit Case(s) with**
		Type[a]	**%S**			
1	975	Bit	3	ESP + FGD	ESP-1, ESP-3	SCR
2	975	Bit	3	FF + FGD	FF-1	SCR
3	975	Bit	3	HESP + FGD	HESP-1	SCR
4	975	Bit	0.6	ESP	ESP-4, ESP-6	
5	975	Bit	0.6	FF	FF-2	
6	975	Bit	0.6	HESP	HESP-1	
7	975	Subbit	0.5	ESP	ESP-4, ESP-6	
8	975	Subbit	0.5	FF	FF-2	
9	975	Subbit	0.5	HESP	HESP-1	
10	100	Bit	3	SD + ESP	SD/ESP-1	
11	100	Bit	3	SD + FF	SD/FF-1	
12	100	Bit	3	HESP + FGD	HESP-1	
13	100	Bit	0.6	ESP	ESP-4, ESP-6	
14	100	Bit	0.6	FF	FF-2	
15	100	Bit	0.6	HESP	HESP-1	
16	100	Subbit	0.5	ESP	ESP-4, ESP-6	
17	100	Subbit	0.5	FF	FF-2	
18	100	Subbit	0.5	HESP	HESP-1	

a. Bit = bituminous coal; Subbit = subbituminous coal.
b. Mercury controls are shown in Table 1.

4.0 COSTS OF REDUCING MERCURY EMISSIONS

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.[12] As an example, for application of SC+PAC injection (ESP-4) to achieve 80% mercury reduction on a 975 MW boiler firing bituminous coal and using ESP, the capital cost contributes about 23% of total annual cost. Therefore, for such technologies, an assessment of costs needs to be based on total annual costs. Accordingly, total annual costs of controlling mercury emissions from coal-fired electric utility boilers are examined in this section. These costs include annualized capital charge, annual fixed operation and maintenance (O&M) costs, and annual variable O&M costs.

First, costs are estimated for some of the model plants[b] using the NETL Mercury Control Cost Model described briefly below. Second, the cost impacts of some selected variables are determined. Third, the NETL model results are used to develop indications of cost estimates for those plants for which such results are not available. Next, potential future improvements in these cost estimates are discussed. Finally, mercury control costs are discussed in light of current costs of NO_x controls. During discussions of cost estimates, R&D areas are identified for near-term emphasis.

4.1 NETL Mercury Control Cost Model

The Department of Energy's National Energy Technology Laboratory (NETL) has developed a cost model for estimating the costs of mercury control options for coal-fired electric utility boilers. This cost model, called the NETL Mercury Control Cost Model (hereafter referred to as the cost model), can provide capital and O&M costs estimated in 2000 constant dollars for power plant applications of selected mercury control technologies. The model has been used in the past to characterize costs associated with PAC injection on certain model boilers.[13] For this work, the PAC injection rate algorithms described in Section 3.2 were incorporated into this model. An overview of this model can be seen in Attachment 1 in the Appendix.

4.2 Cost Model Results

This section describes the estimates of total annual cost for mercury control technology applications on some[c] model plants obtained using the cost model. It is noted that these estimates are based on currently available data and, as explained later, may be improved with R&D efforts.

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

(1) Mercury concentration in the flue gas was taken to be 10 $\mu g/Nm^3$. This concentration has been used in previous cost studies and is in the range of concentration reported for utility boilers.[1, 12]

(2) As mentioned in Section 3.2, for each of technologies ESP-1, ESP-3, ESP-4, and ESP-6, two separate sets of correlations, relating PAC injection rate ($lb/10^6$ acf) to mercury removal efficiency (%), were created for use with bituminous-coal-fired boilers. The first of these sets, hereafter referred to as the *pilot-scale PAC injection rate*, was derived using presently available pilot-scale test data. The other set, hereafter referred to as the *ICR/pilot-scale PAC*

[b] As described in Section 3.2, PAC injection rate algorithms could not be determined for the technologies used in model plant applications 2, 3, 5, 6, 9, 11, 12, 14, 15, and 18. As such, costs associated with these applications could not be modeled with the NETL cost model.
[c] See footnote b.

injection rate, was derived using preliminary ICR results for flyash capture of mercury (i.e., no PAC injection) and pilot-scale results for PAC injection. Accordingly, the cost of applications of technologies ESP-1, ESP-3, ESP-4, and ESP-6 was determined using pilot-scale PAC injection rate and ICR/pilot-scale PAC injection rate correlations.

(3) PAC injection rate correlations (see Section 3.2) generally reflect that PAC injection requirements increase nonlinearly with increase in mercury removal efficiency. To characterize the impact of this behavior, wherever possible, model plant cost estimates were obtained for mercury removal efficiencies of 60, 70, 80, and 90%.

(4) In general, for any given mercury removal requirement, the PAC injection rate goes down if the temperature of the flue gas is lowered. For this reason, the flue gas is cooled by water injection in some technologies (see Table 1). However, water injection into acidic flue gas can potentially lead to corrosion of downstream equipment. To avoid this, an approach to acid dew point (ADP) of 18 ^{o}F was used in applications of technologies with SC (i.e., ESP-4, ESP-6, ESP-7, and FF-2).[14] For these technology applications, the extent of SC provided was determined based on the temperature of the flue gas before cooling and the temperature nearest to the above approach to ADP for which a PAC injection rate correlation was available.

Note that, in the high sulfur coal applications with relatively high ADPs, this constraint resulted in no SC if the SO_2 control technology was wet FGD. However, in applications using SD for SO_2 control, SC is inherent and acid gases are removed prior to PAC injection; therefore, this constraint was not applied.

(5) No data are currently available for recycling of sorbent in technology applications utilizing PAC injection and PFF. Accordingly, no sorbent recycle was used in applications of ESP-3 and ESP-6 technologies.

(6) In flue gas of bituminous-coal-fired boilers, 70% of the total mercury is oxidized and 30% is Hg^0. Corresponding numbers for boilers firing subbituminous coals are 25% oxidized and 75% Hg^0. These mercury speciation numbers were determined from a preliminary analysis of ICR data (see Attachment 2 in the Appendix).

(7) Wet FGD removes 100% of oxidized mercury and no Hg^0. This is based on the fact that mercuric chloride (the assumed major oxidized species) is soluble in water while Hg^0 is insoluble. It is anticipated that ongoing research on wet scrubbers will result in improved performance through the use of reagents or catalysts to convert mercury to chemical compounds that are soluble in aqueous-based scrubbers.

(8) SCR use increases oxidized mercury content in flue gas by 35% for both bituminous- and subbituminous-coal-fired boilers. This increase in mercury oxidation was determined from a preliminary analysis of ICR data (see Attachment 2 in the Appendix).

(9) In each of the model plant cost determinations, a plant capacity factor of 65% was used.

(10) The cost of PAC was taken to be $1.0/kg.[12]

Other specifications can be seen in Attachments 1, 2, and 3 in the Appendix.

<u>Boilers firing bituminous coals and utilizing cold-side ESPs</u>

As shown in Table 3, there are several potential options to reduce mercury emissions from boilers that fire bituminous coals and use ESPs for PM control. For low-sulfur bituminous-coal-fired boilers, these options include SC + PAC injection (ESP-4) and SC + PAC Injection + PFF (ESP-6). For large boilers firing high-sulfur bituminous coals, these options include PAC injection (ESP-1) + wet FGD and PAC injection + PFF (ESP-3) + wet FGD. For smaller boilers (typically less than 300 MW), these options include SD + PAC injection + ESP (SD/ESP-1).

As seen in Table 3, for ESP-4 application on low-sulfur bituminous-coal-fired boilers using pilot-scale PAC injection rates, estimated total annual cost ranges from 2.81 mills/kWh for a 100 MW boiler removing 90% of total mercury to 0.53 mill/kWh for a 975 MW boiler removing 60% of total mercury. The corresponding costs with ICR/pilot-scale PAC injection rates are 1.65 mills/kWh for the 100 MW boiler and 0.24 mill/kWh for the 975 MW boiler. In general, these results reflect that, for a given boiler, the total annual cost increases non-linearly with increase in mercury reduction requirement in concert with the behavior of the PAC injection rate algorithms (see Attachment 2 in the Appendix). *A comparison of results obtained with pilot-scale and ICR/pilot-scale PAC injection rates also indicates that R&D efforts aimed at ensuring broad availability of relatively high levels of flyash capture of mercury have the potential of providing significant reductions in mercury control costs.*

Another option for boilers firing low-sulfur bituminous coals is to utilize ESP-6 for mercury control. For this option, using the pilot-scale PAC injection rates, estimated total annual cost ranges from 4.966 mills/kWh for a 100 MW boiler removing 90% of total mercury to 1.528 mills/kWh for the 975 MW boiler removing 60% of total mercury. The corresponding costs with ICR/pilot-scale PAC injection rates are 3.08 mills/kWh for the 100 MW boiler and 1.353 mills/kWh for the 975 MW boiler. In general, these results reflect that ESP-6 control option is more expensive than ESP-4 because of the capital cost associated with the PFF. *To make this control option more cost-effective, R&D efforts are needed to develop less expensive PFF designs and high capacity sorbents, which may be recycled sufficiently to improve sorbent utilization.*

Table 3. Mercury controls and costs for boilers firing bituminous coals and utilizing ESPs.

Model Plants	Existing Control(s)	Coal	Mercury Control Technology	Removal (%)	975 MW (mills/kWh)	100 MW (mills/kWh)
4, 13	ESP	Low-sulfur bituminous	SC +PAC Injection (ESP-4)	90	1.966 0.883 (ICR)	2.810 1.647 (ICR)
				80	1.017 0.464 (ICR)	1.793 1.184 (ICR)
				70	0.696 0.319 (ICR)	1.442 1.018 (ICR)
				60	0.533 0.240 (ICR)	1.262 0.922 (ICR)
			SC +PAC Injection + PFF (ESP-6)	90	2.381 1.735 (ICR)	4.966 3.080 (ICR)
				80	1.817 1.485 (ICR)	3.783 2.798 (ICR)
				70	1.625 1.397 (ICR)	3.170 2.695 (ICR)
				60	1.528 1.353 (ICR)	2.957 2.637 (ICR)
1, 10	ESP + FGD (SD for 100 MW boiler)	High-sulfur bituminous	PAC Injection (ESP-1, SD/ESP-1)	90	2.594 0.427 (ICR)	1.925 1.094 (ICR)
				80	0.727 NA (ICR)[a]	1.197 0.759 (ICR)
				70	0.006[b] NA (ICR)[a]	0.945 0.637 (ICR)
				60	NA[b] NA (ICR)[a]	0.815 0.008 (ICR)
			PAC Injection + PFF (ESP-3)	90	2.086 1.416 (ICR)	c
				80	1.501 NA (ICR)[a]	c
				70	1.273 NA (ICR)[a]	c
				60	NA[b] NA (ICR)[a]	c

a. NA = Not available. Based on 70% of total mercury being oxidized, mercury removal with flyash being about 58%, and all of oxidized mercury being removed in wet FGD, a minimum of about 87% of total mercury is removed.
b. The cost of monitoring of mercury emissions is 0.006 mill/kWh. Based on 70% of total mercury being oxidized, no mercury removal with flyash, and all of oxidized mercury being removed in wet FGD, a minimum of 70% of total mercury is removed.
c. No mercury control technology with PFF is utilized.

As seen in Table 3, for ESP-1 application on a large (975 MW) high-sulfur bituminous-coal-fired boiler that uses wet FGD for SO_2 control, using pilot-scale PAC injection rates, estimated total annual cost ranges from 2.594 mill/kWh for removing 90% of total mercury to 0.006 mill/kWh (cost of monitoring of mercury emissions) for removing 70% of total mercury. The costs with ICR/pilot-scale PAC injection rates are 0.427 mill/kWh for 90% removal and 0.006 mill/kWh for about 87% removal. Note that, with the assumptions of this work, a minimum of 70% of total mercury is removed in wet FGD if no mercury is removed with flyash (pilot-scale test results) and a minimum of about 87% is removed if about 58% of mercury is removed with flyash (preliminary ICR data analyses results). These results reflect that, if significant amounts of mercury can be captured along with flyash in ESP and in wet FGD, cost of achieving high levels of mercury removal would be quite low. *Considering these results, R&D efforts are needed to ensure that these mercury capture mechanisms are broadly available.*

Another option for large boilers firing high-sulfur bituminous coals and using wet FGD is to utilize ESP-3 for mercury control. Using this option on a 975 MW boiler, with pilot-scale PAC injection rates, estimated total annual cost ranges from 2.086 mills/kWh for removing 90% of total mercury to 1.273 mills/kWh for removing 70% of total mercury. The costs with ICR/pilot-scale PAC injection rates are 1.416 mills/kWh for removing 90% of total mercury and 0.006 mills/kWh for about 87% removal. Interestingly, this control option is more cost-effective than the one using PAC injection (ESP-1) at 90% mercury removal. However, at or below 80% removal, this option is more expensive because PAC injection rate decreases more rapidly than capital cost of PFF. *It may be possible to make this option competitive across a wide range of mercury removal efficiency by conducting R&D efforts directed towards reducing both PFF capital cost and operating cost through sorbent recycling.*

Finally, as seen in Table 3, for ESP-1 application on a relatively small boiler (100 MW) that fires a high-sulfur bituminous coal and uses a SD for SO_2 control, with pilot-scale PAC injection rates, estimated total annual cost ranges from 1.925 mills/kWh for removing 90% of total mercury to 0.815 mills/kWh for removing 60% of total mercury. The corresponding costs with ICR/pilot-scale PAC injection rates are 1.094 and 0.008 mills/kWh, respectively. A significant increase in costs is observed on increasing the mercury control requirement from 80 to 90%. *Again, considering the differences in total annual costs obtained using ICR/pilot-scale and pilot-scale PAC injection rates, R&D efforts aimed at providing broad availability of relatively high levels of flyash capture of mercury are needed.*

<u>Boilers firing subbituminous coals and utilizing cold-side ESPs</u>

Shown in Table 4 are two potential options to reduce total mercury emissions from boilers that fire subbituminous coals and use ESPs for PM control. These options include SC + PAC injection (ESP-4) and SC + PAC injection + PFF (ESP-6).

Table 4. Mercury control options and costs for boilers firing subbituminous coals and utilizing ESPs.

Model Plants	Existing Controls	Coal	Mercury Control Technology	Removal (%)	975 MW (mills/kWh)	100 MW (mills/kWh)
7, 16	ESP	Low-sulfur subbituminous	SC +PAC Injection (ESP-4)	90	2.384	3.232
				80	1.150	1.915
				70	0.731	1.460
				60	0.473	1.174
			SC +PAC Injection + PFF (ESP-6)	90	1.444	2.754
				80	1.419	2.723
				70	1.410	2.712
				60	1.405	2.703

For ESP-4 application on boilers firing subbituminous coals, estimated total annual costs range from 3.232 mills/kWh for a 100 MW boiler removing 90% of total mercury to 0.473 mill/kWh for the 975 MW boiler removing 60% of total mercury. Further, total annual cost appears to drop sharply as mercury removal requirement is reduced from 90% to 80% due to the nonlinear nature of the PAC injection rate algorithms.

For ESP-6 application on boilers firing subbituminous coals, estimated total annual cost ranges from 2.754 mills/kWh for a 100 MW boiler removing 90% of total mercury to 1.405 mills/kWh for the 975 MW boiler removing 60% of total mercury. Interestingly, this control option is more cost-effective than the one using SC + PAC injection (ESP-4) at 90% mercury removal. However, at or below 80% removal, this option is more expensive because PAC injection rate decreases more rapidly than capital cost of PFF. *These results again point towards possibilities of making this option competitive across a wide range of mercury removal efficiency by conducting R&D efforts directed towards reducing both the PFF capital cost and operating cost through sorbent recycling.*

A comparison of the results shown in Tables 4 and 3 reveals that applications of SC+PAC injection (ESP-4) to achieve mercury reductions in excess of 70% would cost more for boilers firing subbituminous coals compared to boilers firing bituminous coals. Further, in general, relatively few wet scrubbers would be used on subbituminous-coal-fired boilers. Considering these factors, R&D efforts are needed to ensure that cost-effective control of mercury is achieved at these boilers.

Boilers firing subbituminous coals and utilizing FFs

As seen in Table 5, for boilers firing subbituminous coals and utilizing SC + PAC injection (FF-2) for mercury control, estimated total annual cost ranges from 1.120 mills/kWh for a 100 MW boiler removing 90% of total mercury to 0.219 mill/kWh for the 975 MW boiler removing 60% of total mercury. These cost estimates reflect that the combination of SC + PAC injection + FF is quite efficient in removing mercury.

Table 5. Mercury control costs for boilers firing subbituminous coals and utilizing FFs.

Model Plants	Existing Controls	Coal	Mercury Control Technology	Removal (%)	975 MW (mills/kWh)	100 MW (mills/kWh)
8, 17	FF	Low-sulfur subbituminous	SC +PAC Injection (FF-2)	90	0.423	1.120
				80	0.299	0.977
				70	0.226	0.888
				60	0.219	0.879

Boilers utilizing SCRs for NO_x control

Table 6 shows the total annual cost resulting from application of SCR on a large (975 MW) boiler firing a high-sulfur bituminous coal and using wet FGD for SO_2 control. As mentioned before, in this work it has been assumed that flue gas resulting from bituminous coal combustion has an oxidized mercury content of 70%, and SCR augments this by 35%. This leads to a total of 94.5% of total mercury being oxidized mercury after SCR.

Using the results of ICR data analysis (see Section 3.2), about 58% of total mercury is captured along with flyash in ESP and all of the remaining oxidized mercury is captured in wet FGD. Thus, a total mercury capture of 97.6% is achieved, and the cost of this removal is 0.006 mills/kWh, which is simply the cost of monitoring of mercury emissions. On the other hand, using pilot-scale test results, no mercury is captured along with flyash in ESP and all of the oxidized mercury is captured in wet FGD. Therefore, a total mercury capture of 94.5% is achieved, and the cost of this removal is 0.006 mill/kWh; i.e., the cost of monitoring of mercury emissions.

Table 6. Mercury control costs for boilers using SCRs.

Model Plant	Existing Controls	Coal	Mercury Control Technology	Removal (%)	975 MW (mill/kWh)
1	ESP + wet FGD	High-sulfur bituminous	None	97.6	0.006 (ICR)
				94.5	0.006

4.3 Cost Impacts of Selected Variables

In addition to estimating mercury control costs described above, impacts of certain selected variables on these costs were examined via sensitivity analyses conducted using the cost model with pilot-scale PAC injection rates. These analyses are described below, and additional information on these analyses is presented in Attachment 3 in the Appendix. Note that the boiler size of 500 MW is approximately the midpoint of the range of boiler sizes in the model plant applications and, therefore, is representative of this range. As such, the sensitivity analyses use the results obtained for a 500 MW boiler.

(1) Approach to acid dew point. In determinations of mercury control costs for model plant applications described above, the approach to acid dew point was kept at 18 ^{o}F. However, there was a concern that in some cases this may not be adequate to prevent corrosion of downstream equipment. For this analysis, this approach was increased to 40 ^{o}F for model plant applications 4, 7, and 8 evaluated with a boiler size of 500 MW. Note that the approach to dew point is a concern when SC is used; i.e., in applications with low-sulfur bituminous and subbituminous coals.

Shown in Tables 7, 8, and 9 are the costs at nominal (ADP + 18 ^{o}F) conditions and at ADP + 40 ^{o}F. As seen in Table 7, for a 500 MW boiler firing low-sulfur bituminous coal and using ESP-4, the total annual cost increase ranges from 126.3 to 38.2%. Again for the same boiler using ESP-6, the cost increase ranges from 18.8 to 2%. Interestingly, the results for subbituminous coal presented in Tables 8 and 9 reflect that total annual cost *decreases* with an increase in approach to ADP. This is due to a significant decrease in water injection requirements, while PAC injection does not increase much to provide the required mercury removal. These results indicate that, for bituminous-coal-fired boilers using ESPs, increase in approach to ADP can influence costs significantly. However, the same is not true for subbituminous-coal-fired boilers. *The results also reveal that sorbents with reduced temperature dependence of the mercury adsorption process need to be developed for use with ESPs*.

(2) Sorbent recycle. As discussed above, estimates of mercury control costs for model plants using PFF obtained using no sorbent recycle, are, in general, higher than those of other options. The purpose of this sensitivity analysis was to examine the impact of increasing sorbent utilization in ESP-3 and ESP-6 applications on associated costs. Specifically, cost estimates were obtained with 20% of PAC recycled in the following applications evaluated with a 500 MW boiler: model plant 1 retrofitted with ESP-3; model plant 4 retrofitted with ESP-6; and model plant 7 retrofitted with ESP-6.

The results shown in Tables 7 and 8 reflect that a recycle rate of 20% does not have much of an impact on total annual costs because capital cost of PFF is the dominant cost component. *In order to utilize benefits of increased sorbent utilization, higher recycle rates would be needed, but such rates would require that sorbents used have relatively high adsorption capacities. This indicates that R&D efforts aimed at developing such sorbents are needed.*

Table 7. Impact on mercury control costs resulting from increase in approach to ADP and recycling of sorbent for boilers firing bituminous coals and utilizing ESPs.

Model Plant	Existing Controls	Coal	Mercury Control Technology	Removal (%)	500 MW (mills/kWh)
4	ESP	Low-sulfur bituminous	SC + PAC injection (ESP-4)	90	2.095 4.741 (ADP + 40)
				80	1.132 2.282 (ADP + 40)
				70	0.804 1.451 (ADP + 40)
				60	0.637 1.030 (ADP + 40)
			SC + PAC injection + PFF (ESP-6)	90	2.650 3.263 (ADP + 40) 2.457 (Recycle)
				80	2.075 2.307 (ADP + 40) 1.989 (Recycle)
				70	1.879 1.982 (ADP + 40) 1.829 (Recycle)
				60	1.779 1.816 (ADP + 40) 1.747 (Recycle)
1	ESP + wet FGD	High-sulfur bituminous	PAC injection + PFF (ESP-3)	90	2.324 2.173 (Recycle)
				80	1.727 1.686 (Recycle)
				70	0.006 0.006 (Recycle)[a]
				60	NA[a]

a. The cost of monitoring of mercury emissions is 0.006 mill/kWh. Based on 70% of total mercury being oxidized, no mercury removal with flyash, and all of oxidized mercury being removed in wet FGD, a minimum of 70% of total mercury is removed.

Table 8. Impact on mercury control costs resulting from increase in approach to ADP and recycling of sorbent for boilers firing subbituminous coals and utilizing ESPs.

Model Plant	Existing Controls	Coal	Mercury Control Technology	Removal (%)	500 MW (mill/kWh)
7	ESP	Low-sulfur subbituminous	SC + PAC injection (ESP-4)	90	2.513 2.392 (ADP + 40)
				80	1.261 1.140 (ADP + 40)
				70	0.835 0.714 (ADP + 40)
				60	0.571 0.478 (ADP + 40)
			PAC injection + PFF (ESP-6)	90	1.693 1.683 (ADP + 40) 1.686 (Recycle)
				80	1.667 1.597 (ADP + 40) 1.664 (Recycle)
				70	1.658 1.567 (ADP + 40) 1.657 (Recycle)
				60	1.652 1.550 (ADP + 40) 1.652 (Recycle)

Table 9. Impact on mercury control costs resulting from increase in approach to ADP for boilers firing subbituminous coals and utilizing FFs.

Model Plant	Existing Controls	Coal	Mercury Control Technology	Removal (%)	500 MW (mill/kWh)
8	Fabric Filter	Low-sulfur subbituminous	SC +PAC Injection (FF-2)	90	0.520 0.399 (ADP + 40)
				80	0.392 0.271 (ADP + 40)
				70	0.315 0.216 (ADP + 40)
				60	0.308 0.197 (ADP + 40)

(3) Addition of ductwork to increase flue gas residence time. Adsorption of mercury on PAC is dependent on the time of contact between the flue gas and PAC. In general, about half of the existing utility boilers have a flue gas residence time in the duct of 1.0 s and about 30% have a time of 2.0 s.[15] Although it is not clear at this time as to how much time is needed for particular levels of mercury capture, in this sensitivity analysis the impact of adding ductwork to increase the flue gas residence time by 1 s on the cost of mercury control was evaluated as a conservative measure. This analysis was conducted using model plant 4 with a 500 MW boiler retrofitted with ESP-4.

The results shown in Figure 1 reflect that the impact of adding ductwork on total annual cost is quite small. The increase in cost ranges from 16.4% at the lowest cost of 0.535 mill/kWh to 4.3% at the highest cost of 2.095 mills/kWh. Based on this analysis, it appears that addition of ductwork is not a sensitive cost parameter.

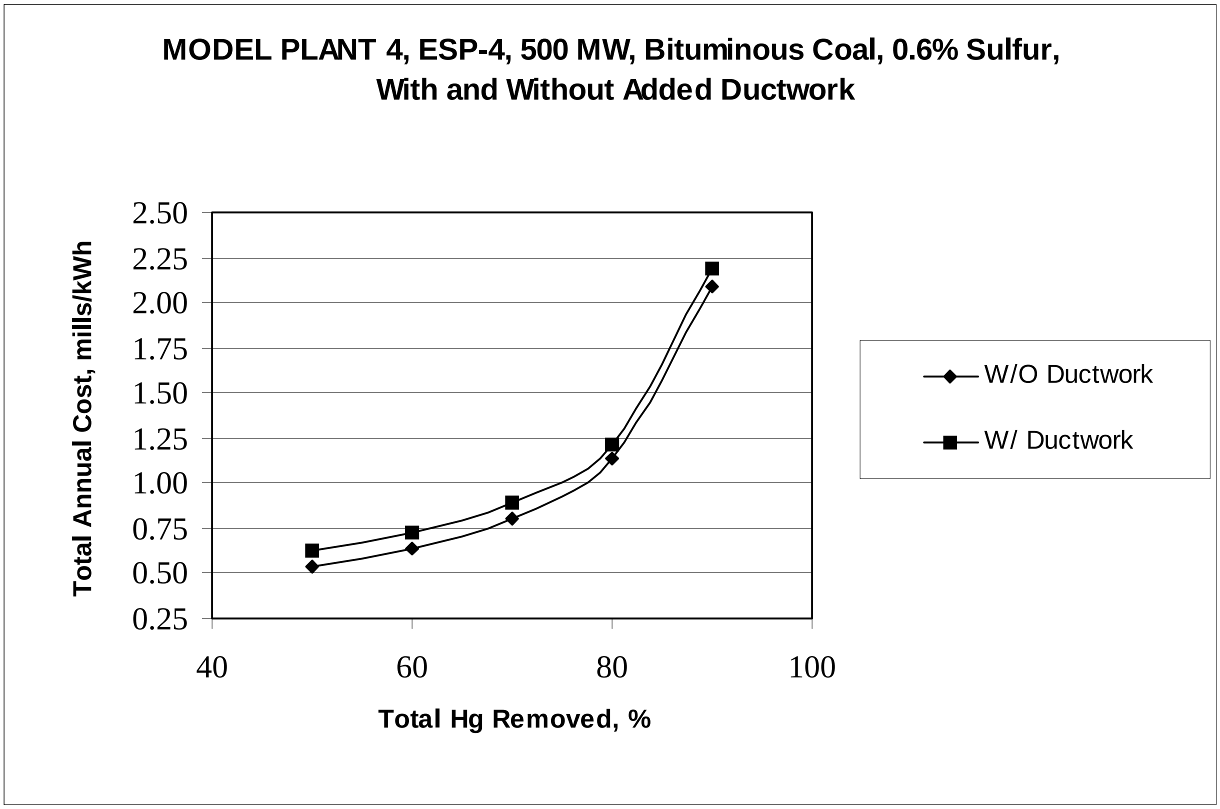

Figure 1. Change in total annual cost resulting from addition of ductwork to provide additional residence time.

(4) Use of a composite PAC and lime sorbent. As discussed before, high levels of mercury have been removed in pilot-scale tests using lime and PAC with PFF.[11] To assess the potential economic impact, this analysis was based on removing 90% of mercury from model plant 4 retrofitted with ESP-7 and using a composite PAC-lime sorbent, with a PAC:lime mass ratio of 2:19.[11]

The results of this analysis shown in Figure 2 reflect that use of the composite sorbent lowers the total annual cost by 34.7 to 38.1%. *Based on these results, the use of composite PAC-lime sorbent needs to be examined in future R&D efforts.*

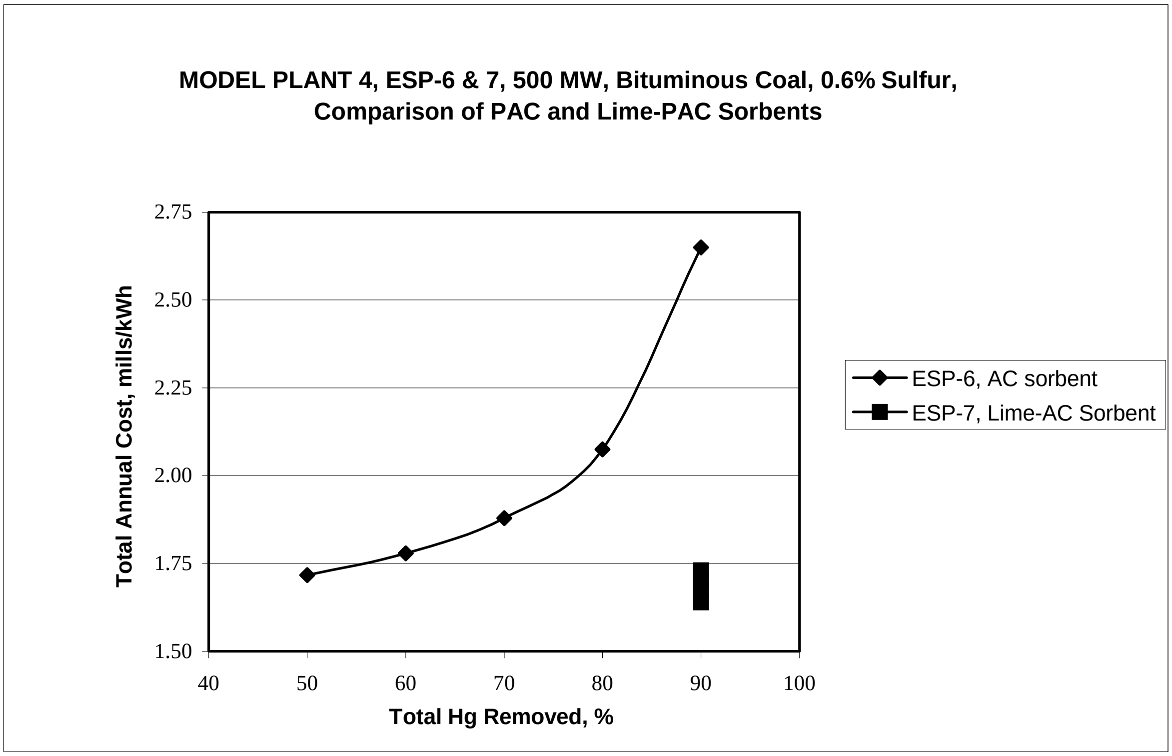

Figure 2. Change in total annual cost resulting from use of a composite PAC-lime sorbent instead of PAC.

4.4 Cost Indications for Other Model Plants

As discussed in Section 3.2, since data are not available on mercury control technology applications involving HESPs or boilers firing bituminous coals and using FFs, PAC injection rate algorithms could not be developed for these applications. Consequently, cost estimates for these applications (i.e., model plants 2, 3, 5, 6, 9, 11, 12, 14, 15, and 18) could not be obtained using the cost model. In this section, estimates of cost for these latter applications are developed using the estimates described in previous sections.

Cooling the flue gas after the air preheater, injecting PAC, and collecting the spent PAC in a downwind PFF may achieve mercury control on boilers equipped with HESPs. This configuration is identical to ESP-6, with only the location of the ESP being different. Therefore, mercury reduction performance and costs should be similar to those found for ESP-6. However, on boilers equipped with HESPs and firing high-sulfur bituminous coals, application of SC may not be possible due to corrosion concerns; for such boilers, mercury control may be achieved using ESP-3. With these considerations, cost of mercury control technology applications involving HESPs are: model plant 3 costs are the same as those for model plant 1 with ESP-3; model plant 6 costs are the same as those for model plant 4 with ESP-6; model plant 9 costs are the same as those for model plant 7 with ESP-6; model plant 12 costs are the same as those for model plant 12 with ESP-3; model plant 15 costs are the same as those for model plant 13 with ESP-6; and model plant 18 costs are the same as those for model plant 16 with ESP-6.

The combination of PAC injection and FF provides better sorbent utilization than the corresponding PAC injection and ESP combination because FF provides added residence time and a contact bed for increased adsorption of mercury. This superior performance of FF has been validated in full-scale tests on MWCs and pilot-scale tests on coal-fired combustors. Field tests have shown that it takes 2 to 3 times more PAC to achieve the same performance on MWCs equipped with dry scrubbers and ESPs than with dry scrubbers and FFs.[16] As a result of increased sorbent utilization, total annual cost of a PAC injection and FF application would be lower than that of the corresponding PAC injection and ESP combination. An analysis of cost data for ESP-4 applications on Model Plants 7 and 16 and FF-2 applications on Model Plants 8 and 17 (see Tables 4 and 5) reveals that, in reducing mercury emissions between 60 to 90% using FFs instead of ESPs, total annual cost decreases by an average of about 70% for the 975 MW boiler and 45% for the 100 MW boiler. Considering these numbers, on average about 58% decrease in total annual cost may be expected if FFs are used in place of ESPs for mercury removal.

4.5 Summary of Mercury Control Costs and Projections for Future Applications

Shown in Table 10 below is a summary of costs of mercury control technology applications developed in the previous sections. This summary presents current estimates of cost developed using the pilot-scale PAC injection rates and projections based on use of potentially more effective sorbent. The following assumptions were used in developing these estimates.

(1) A mercury capture of 80% is obtained in technologies using ESPs and 90% in technologies using FFs. This is based on the consideration that it is more cost-effective to remove mercury on boilers equipped with FFs.

(2) For technology applications on bituminous-coal-fired boilers using ESPs, current estimates are based on levels of mercury capture on flyash derived from pilot-scale test data. ICR data, however, reflect that levels of capture higher than those seen in pilot-scale tests may be occurring. In this light, these cost estimates may be conservative.

(3) Current estimates for boilers using HESPs, as well as boilers firing bituminous coals and using FFs, are based on the information presented in Section 4.4. For other cases, these estimates are based on the results obtained with the cost model.

(4) Results of sensitivity analyses presented in Section 4.3, especially impacts of increase in approach to acid dew point at boilers firing bituminous coals and using ESP-4, are not included in the current estimates because the estimates are preliminary in nature and because it is not clear whether such an increase is broadly applicable. Generally an approach of ADP + 18 ^{o}F is considered to be optimum.[14] Where a higher approach is desired, use of ESP-6 may be less expensive.

(5) Finally, sensitivity analyses reflect that use of a composite sorbent such as PAC + lime may remove mercury quite cost-effectively. Although some data are currently available

for applications using a PFF, there does not appear to be any significant technical constraint to using such sorbents in other applications. Consequently, projected costs of mercury controls are based on using such sorbents. Specifically, sensitivity analyses reflected that a 35 - 40% decrease in total annual cost might be experienced if a composite sorbent is used. Since these indications are based on using PFF, the capital cost of which is a dominant component of the corresponding total annual cost, in applications without PFF greater benefits may be possible. Considering these factors, a 40% reduction in total annual cost is used to arrive at the cost projections shown in Table 10.

Earlier, EPA's Office of Air and Radiation (OAR) conducted preliminary analyses examining potential pollution control options for the electric power industry to lower the emissions of its most significant air pollutants, including mercury.[3] These analyses were conducted using the Integrated Planning Model (IPM)[17], which was supplemented with previously developed estimates of performance and cost of mercury emission control technologies. These estimates were based on using lime with PAC injection. In these previous estimates, mercury control costs ranged from 0.17 to 1.76 mills/kWh for boilers ranging in size from 100 to 1000 MW.[12] As seen from Table 10, the range of projected cost estimates (i.e., 0.183 to 2.27 mills/kWh) is comparable to the range of previously developed estimates.

Table 10. Mercury control technology application cost estimates based on currently available data and projections for future.[a]

Coal		Existing Controls	Mercury Control	Current Estimates of Mercury Control Cost (mills/kWh)	Projected Cost of Mercury Controls (mills/kWh)
Type	%S				
Bit	3	ESP + FGD	ESP-1, SD/ESP-1	0.727 – 1.197	0.436 – 0.718
Bit	3	FF + FGD	FF-1	0.305 – 0.502	0.183 – 0.301
Bit	3	HESP + FGD	ESP-3	1.501 – NA[b]	0.901 – NA[b]
Bit	0.6	ESP	ESP-4	1.017 – 1.793	0.610 – 1.076
Bit	0.6	FF	FF-2	0.427 – 0.753	0.256 – 0.452
Bit	0.6	HESP	HESP-1	1.817 – 3.783	1.090 – 2.270
Subbit	0.5	ESP	ESP-4	1.150 – 1.915	0.69 – 1.149
Subbit	0.5	FF	FF-2	0.423 – 1.120	0.254 – 0.672
Subbit	0.5	HESP	HESP-1	1.419 – 2.723	0.851 – 1.634

a. The boiler size range is 975-100 MW.
b. NA = not available.

Finally, it is noted that, in the wake of recent NO_x control regulations, many plants may elect to install SCRs. As discussed in Section 4.2, mercury control costs may be negligible at plants using SCR and wet FGD.

4.6 Comparison of Mercury and NO_x Control Costs

An understanding of the mercury control costs may be gained by comparing these with costs of currently used controls for NO_x. Shown in Table 11 are the ranges of total annual costs in 2000 constant dollars for the mercury controls examined in this work and for two of the currently used NO_x control technologies; i.e., low NO_x burner (LNB) and SCR. NO_x control costs are shown for applications on dry-bottom, wall-fired boilers ranging in size from 100 to 1000 MW and being operated at a capacity factor of 0.65. In general, costs associated with LNB and SCR are expected to span the costs of currently used NO_x controls; therefore these costs were chosen for comparison with mercury control costs. The LNB and SCR costs were derived from the information available in Reference 16.

As seen from Tables 10 and 11, total annual costs for mercury controls lie mostly between applicable costs for LNB and SCR. However, Table 10 shows total annual costs of mercury controls to be higher for the minority of plants using HESPs. Excluding these costs, both currently estimated and projected mercury control costs are in the spectrum of LNB and SCR costs.

Table 11. Comparison of mercury control costs with NO_x control costs.

Control	Total Annual Cost (mills/kWh)
Mercury Control Costs	0.305 – 3.783[a] 0.183 to 2.270[b]
LNB Costs	0.210 – 0.827
SCR Costs	1.846 – 3.619

a. Estimated costs based on currently available data.
b. Projected costs.

5.0 SUMMARY

Preliminary estimates of costs of PAC injection-based mercury control technologies for coal-fired electric utility boilers have been determined. These estimates include those based on currently available data from pilot-scale PAC injection tests, as well as projections for future applications of more effective sorbent. Estimates based on currently available data range from 0.305 to 3.783 mills/kWh. However, the higher costs are associated with the minority of plants using HESPs. If these costs are excluded, the estimates range from 0.305 to 1.915 mills/kWh.

Cost projections, developed based on using a composite lime-PAC sorbent for mercury removal, range from 0.183 to 2.270 mills/kWh with the higher costs being associated with the minority of plants using HESPs.

For technology applications on bituminous coal-fired boilers using ESPs, current estimates are based on levels of mercury capture on flyash derived from pilot-scale test data. ICR data, however, reflect that levels of capture higher than those seen in pilot-scale tests may be occurring. In this light, the cost estimates for technology applications on bituminous-coal-fired boilers using ESPs may be conservative.

Results of sensitivity analyses conducted on total annual cost of mercury controls reflect that: (1) addition of ductwork to increase residence time does not have a significant impact on cost, (2) a sorbent recycle rate of 20% is not adequate to reflect significant improvement in sorbent utilization, (3) increasing approach to ADP from ADP + 18 ^oF to ADP + 40 ^oF can have a significant impact on total annual costs of mercury controls applicable to bituminous-coal-fired boilers, and (4) a composite sorbent containing a mixture of PAC and lime offers great promise of significantly reduced control costs.

A comparison of mercury control costs with those of NO_x controls reveals that total annual costs for mercury controls lie mostly between applicable costs for LNB and SCR. As mentioned above, estimates of total annual cost are higher where applicable to the minority of plants using HESPs. Excluding these costs, both currently estimated and projected mercury control costs are in the spectrum of LNB and SCR costs.

Based on this work, some R&D areas are identified for near-term emphasis. In general, development of sorbents with reduced temperature dependence of the mercury adsorption process would provide reduction in mercury control costs and potential for broad use. Considering the differences in total annual costs obtained using ICR/pilot-scale and pilot-scale PAC injection rates, R&D efforts aimed at ensuring broad availability of relatively high levels of flyash capture of mercury have the potential of providing significant reductions in mercury control costs, especially for ESP-based controls. The costs of PFF-based mercury control options may be improved by developing less expensive PFF designs and high capacity sorbents, which may be recycled sufficiently to improve sorbent utilization. Such recycling would require that sorbents used have relatively high adsorption capacities. Finally, the use of composite PAC-lime sorbent needs to be examined in future R&D efforts.

The performance and cost estimates of the PAC injection-based mercury control technologies presented in this report are based on relatively few data points from pilot-scale tests and, therefore, are considered to be preliminary. Factors that are known to affect the adsorption of mercury on PAC or other sorbent include the speciation of mercury in flue gas, the effect of flue gas and ash characteristics, and the degree of mixing between flue gas and sorbent. This mixing may be especially important where sorbent has to be injected in relatively large ducts. The effect of these factors may not be entirely accounted for in the relatively few pilot-scale data points that comprised the basis for this work. Ongoing research is expected to address these issues and to improve the cost effectiveness of using sorbents for mercury control. Further research is also needed on ash and sorbent residue to evaluate mercury retention and the potential for release back into the environment.

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APPENDIX

Assessment of Mercury Control Options for Coal-fired Power Plants (DOE)

August 11, 2000

Mr. James D. Kilgroe
United States Environmental Protection Agency
National Risk Management Research laboratory
Air Pollution Prevention and Control Division
Research Triangle Park, NC 27711

Dear Jim:

As part of our collaboration in the study and evaluation of mercury control options for coal-fired power plants, a technical evaluation of commercial emission control technologies and emerging technologies has been performed by the National Energy Technology Laboratory (NETL) using our Mercury Control Performance and Cost Model (MCPCM).

Four individual attachments to this letter document the results of our work as follows:

1) Description of NETL's Mercury Control Performance and Cost Model;
2) Description of Mercury Control Performance Algorithms Used in the NETL Mercury Control Performance and Cost Model;
3) Summary of Mercury Control Cases Analyzed with NETL's Mercury Control Performance and Cost Model; and
4) Results of all Model Runs (Excel Spreadsheet Format).

The first attachment contains a detailed description of MCPCM, including a discussion of the model's layout, documentation of the reference power plants used in the model, and documentation of the methodology used to estimate capital and O&M costs. The second attachment documents the mercury control performance algorithms used in the model for the various control configurations specified by EPA. The third attachment defines all of the mercury control cases that were requested by EPA. Different control configurations account for designated combinations of wet scrubbers, fabric filters, spray dryers, electrostatic precipitators, SCR, and sorbent injection systems to control pollutants. The final attachment, an Excel spreadsheet, presents the cost results for all case runs. The total number of individual cases run with MCPCM is 306. Results are presented in both tabular and graphical formats. For each case, the model estimates the cost of control in mills/kWh associated with the designated mercury removal level as a percentage of the inlet mercury concentration.

3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880 ❖ 626 Cochrans Mill Road, P.O. Box 10940, Pittsburgh, PA 15236-0940
REPLY TO: Pittsburgh Office

As you are aware, through your involvement in the model development process, there are significant data gaps for mercury control system performance. NETL believes that the results of this analysis should be viewed as preliminary. Our technical evaluation identifies the source of information used in the analysis as well as all major assumptions.

The performance of mercury control technology options is fundamentally based on sorbent injection testing obtained from pilot-scale systems. These data provide the firmest foundation to develop performance algorithms. Although an attempt has been made to include EPA's Mercury Information Collection request (ICR) data, it is highly recommended that such data not be used in the evaluation of mercury control performance at this time. However, in the cases where the mercury control configuration includes additional flue gas control systems such as flue gas desulfurization (FGD) or Selective Catalytic Reduction (SCR), incremental mercury removal has been demonstrated from ICR tests and this preliminary data appropriately incorporated into the performance model. The model assumes 100% capture of oxidized mercury by the scrubber but a more realistic number may be 90%. A special note should be made that the model considers modern forced oxidation wet FGD systems. Existing wet FGD systems that have a low liquid-to-gas ratio or use inhibited oxidation technology may have significantly different incremental mercury removal levels.

Secondary effects that have not been investigated in the present study include a sensitivity analysis of power plant efficiency and mercury concentration in the flue gas. Variations in these parameters may have a significant impact on control design parameters that could also impact the control costs.

If you have any questions, don't hesitate to contact either of us.

Sincerely,

Scott Renninger for
Charles Schmidt

Charles E. Schmidt
Product Manager

Scott Renninger

Scott Renninger
Project Manager

CC: Dennis Smith, NETL
Harvey Ness, NETL
Massood Ramezan, SAIC
Jay Ratafia-Brown, SAIC
Ravi Srivastava, EPA

Assessment of Mercury Control Options for Coal-Fired Power Plants

Prepared for

United States Environmental Protection Agency
National Risk Management Research Laboratory
Air Pollution Prevention and Control Division
Research Triangle Park

Prepared by

United States Department of Energy
National Energy Technology Laboratory

August, 2000

LIST OF ATTACHMENTS

ATTACHMENT 1

Description of
National Energy Technology Laboratory
Mercury Control Performance and Cost Model

Description of the National Energy Technology Laboratory Mercury Control Performance and Cost Model

1. Model Description

The National Energy Technology Laboratory (NETL) Mercury Control Performance and Cost Model (MCPCM) is an Excel spreadsheet model that can be used to assess the performance and cost of mercury (Hg) control systems that utilize activated carbon injection (ACI) and other methods. The primary goal of the model is to calculate key performance parameters that are then used to calculate detailed capital costs and O&M costs of a mercury control technology for either of two types of power plant applications – either a bituminous or subbituminous coal-fired power plant configuration. This overview describes the model layout, its specific capabilities, and its current limitations.

1.1 MCPCM Layout

The spreadsheet model is currently divided into seven (7) different, functional sheets that are integrated together to perform the costing goal defined above. The five sheets are identified below:

Hg Control Scenario Definition Sheet __________*Characterization of Control Technology Retrofit Configurations*

Hg Control Performance Models Sheet__________*Performance Algorithms for Different Control Technology Retrofit Configurations*

Application Input Sensitivity Sheet __________*User Data Input*

Technical Model Results Sheet __________*PowerPlant and Mercury Control Technical Performance Results*

Combustion Calculations Sheet __________*Power Plant Performance Calculations*

Capital Cost Model Sheet __________*Capital Cost Calculations*

System Economic Model Sheet __________*O&M Cost Calculations and Levelized Cost Calculations*

1.1.1 <u>Hg Control Scenario Definition Sheet</u>

This sheet documents the different mercury control technology retrofit scenarios that can potentially be evaluated by the model. The information provided for each scenario is presented below:

Scenario Number: *Number, no units*
This number uniquely identifies each control scenario within the program.

Configuration Designation: Abbreviation that identifies a control technology scenario, e.g., *ESP-1* (activated carbon injection upstream of ESP with no spray cooling)

Configuration Definition: Brief description that uniquely defines a control technology scenario, e.g., ESP-1, "ACI upstream of existing ESP"

Comment: Further descriptive information that qualifies the functionality of the control technology scenario within the model.

Data Sources: Identifies and documents specific data and information sources used to establish the performance of a control technology.

1.1.2 <u>Hg Control Performance Models Sheet</u>

This sheet contains performance models for each control technology configuration identified in the **Hg Control Scenario Definition Sheet** (as currently available). These models currently calculate total sorbent feed (lb/MMacf of flue gas) based on a specified total mercury control efficiency (e.g., 50%) and flue gas temperature.

Currently, each control configuration (e.g., ESP-1) makes use of separate algorithms for mid- to high-sulfur bituminous coals (e.g., Pittsburgh (Pgh) #8) and Western subbituminous coals (e.g., Wyoming PRB). Therefore, the coal type that is specified in the **Application Input Sensitivity Sheet** will determine the specific algorithm that is used for a specified control configuration and application case. These algorithms were developed based on curve-fitting available pilot- and full-scale test data. The data sources are also documented in the sheet.

1.1.3 <u>Application Input Sensitivity Sheet</u>

This sheet is intended as the primary user interface to run up to 20 different mercury control cases simultaneously. For each control case, the sheet defines the desired mercury control requirements, a specific power plant variant of either of two power plant application types, and some key economic parameters used for costing purposes. Additional parametric changes can be made to the model to add greater evaluation flexibility, but these need to be made within the other functional sheets of the model. Model parameters included here are:

1.1.3.1 Mercury Control Parameters

Case Number: *Numerical value, Fixed (e.g., 1,2, etc.)* **–**
Sequentially identifies each application case. Up to 20 cases can be specified.

Hg Removal Configuration Type: *Numerical entry by user (e.g., 1,2, etc.) --*
Specifies the mercury control configuration as documented in the **Hg Control Scenario Definition Sheet**. The user must select a configuration type.

Hg Control Flue Gas Temperature Specification: *Number, units = ^oF (e.g., 250)*
Specifies the temperature at which mercury control is to take place. The program calculates this temperature as follows:

> *Control Temperature = Flue Gas Acid Dew Point Temperature (^oF) + 18 ^oF*
> (For Configurations 1 to 11)
>
> *Control Temperature = 200 ^oF*
> (Current default for all other configurations)

Injection of cooling water can be used to lower the flue gas temperature below the power plant air heater outlet temperature for configurations 1 to 11. Configurations 12 to 18 incorporate wet or dry scrubbing, which yield a relatively low flue gas temperature at their outlet. A default temperature of 200 ^oF is currently used because it represents a value that is below the lower limit of the algorithms contained in the **Hg Control Scenario Definition Sheet**.

Mercury Concentration: *Number, units = $\mu g/Nm^3$ (e.g., 10)*
The total mercury concentration within the flue gas at the exit of the air heater. The user specifies this value.

Mercury Speciation as % Hg^o: *Number as a percentage, no units (e.g., 50)*

The percentage of total mercury that is elemental mercury. The difference is assumed to be oxidized mercury in the form of $HgCl_2$. The user specifies this value.

Total SI (sorbent injection) Mercury Removal Efficiency - % of Hg Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of total mercury that is removed by the control technology.

SI Mercury Removal Efficiency - % Hg^o Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of elemental Hg that is removed by the control technology. This value is currently assumed to be calculated by the performance model, but this capability is currently not available.

ACI Mercury Removal Efficiency - % $HgCl_2$ Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of $HgCl_2$ that is removed by the control technology, but this capability is currently not available.

Sorbent Injection Ratio: *Number, units = lb/MMacf (e.g., 3)*
The primary feed of sorbent (based on lb sorbent per MMacf of flue gas) that corresponds to the specified Hg removal efficiency. The configuration performance model calculates this value.

Sorbent Recycle Split: *Percent, no units (e.g., 10)*
The ratio of recycled spent sorbent to total sorbent feed into the flue gas (expressed as a percentage). This value is currently assumed to be calculated by the performance model, but this capability is currently not available.

FGD Mercury Removal Efficiency - % Hg^o Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of Hg^o (in the flue gas) that is removed by an existing wet FGD system. Mercury removal via an FGD system can be incorporated manually if desired. This is permitted as an option in case the user wants to combine FGD with other mercury removal technologies such as ACI. Set values equal to zero if no wet FGD exists or mercury control scenarios 14 - 18 are being used. If utilized, total mercury control is calculated within the "Technical Model Results Sheet."

FGD Mercury Removal Efficiency - % $HgCl_2$ Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of $HgCl_2$ (in the flue gas) that is removed by the wet FGD system. Mercury removal via an FGD system can be incorporated manually if desired. This is permitted as an option in case the user wants to combine FGD with other mercury removal technologies such as ACI. Set value equal to zero if no wet FGD exists or mercury control scenarios 14 - 18 are being used. If utilized, total mercury control is calculated within the "Technical Model Results Sheet."

If Hg speciation is unknown set value equal to "% Hg^o removal efficiency." For example, if total Hg removal via FGD is to be set at 80% and speciation is unknown, then set both Hg^o and $HgCl_2$ removal efficiencies equal to the 80% value.

Fabric Filter Pressure Drop: *Number, units =* inches H_2O *(e.g., 6)*
Differential pressure across baghouse tubesheet. Input a value if a pulse-jet FF will be added to the plant after the primary particulate collector to collect Hg sorbent. This applies to retrofit scenarios 3, 6, 7, 8, and 11.

Fabric Filter Air/cloth Ratio: *Number, units = ft*/min *(e.g., 12)*
Ratio of volumetric gas flow into baghouse (ft^3/min) to total bag surface area (ft^2). Input a value if a pulse-jet FF will be added to the plant after the primary particulate collector to collect Hg sorbent. This applies to retrofit scenarios 3, 6, 7, 8, and 11.

Fabric Filter Particle Collection Efficiency: *Number as a percentage, no units (e.g., 99.98)*

Mass flow of particulate into baghouse/mass flow of particulate emitted from baghouse. Input a value if a pulse-jet FF will be added to the plant after the primary particulate collector to collect Hg sorbent. This applies to retrofit scenarios 3, 6, 7, 8, and 11.

1.1.3.2 Power Plant Design Parameters

Gross Power Plant Size: *Number, units* = MWe *(e.g., 500)*
Gross power plant electricity output (excludes plant auxiliary power).

Reference Power Plant Type: *Alphanumeric entry (HS* or LS)
HS refers to the high sulfur reference power plant and LS refers to the low sulfur reference plant.

Plant Capacity Factor: *Number as a percentage, no units (e.g., 65)*
Ratio of the energy generated during some time period to the total energy that could have been generated had the plant run at its full rating over the entire time period.

Power Plant Coal Type: *Alphanumeric entry (e.g., Pgh #8*)
Select a coal type from a menu list of six coals. The coal types are Illinois #6, Wyoming PRB, Texas Lignite, Utah Bituminous (LS), Appalachian (HS), Pittsburgh #8, and bituminous process derived fuel (LS). The Combustion Calculations Sheet contains detailed analysis data for each coal (cell range AE61 to AP141).

1.1.3.3 Economic Assessment Parameters

Levelized Carrying Charge Rate: *Number, no units (e.g., 0.133)*
The levelized amount of revenue per dollar of investment in the mercury control system that must be collected in order to pay the carrying charges on the investment.

Sorbent Unit Cost: *Number, units* = $/lb *(e.g., 0.5)*
Unit cost of the activated carbon or other sorbent, including the cost of the material and shipping.

Waste Disposal Removal Service?: *Yes or No*
This logical question is asked to identify the need to treat the mercury laden AC as hazardous waste. **Yes = hazardous,** in which case the AC is removed and processed to remove the mercury; a processing cost can be specified by the user. **No = non-hazardous,** in which case the AC is disposed of with the fly ash; a disposal cost can be specified by the user.

Normal Waste Disposal Cost: *Number, units* =$/ton *(e.g., 30)*
Unit cost of disposing non-hazardous power plant waste, such as fly ash. Use of a negative number indicates a waste byproduct credit.

Hazardous Waste Disposal Cost: *Number, units* =$/ton *(e.g., 1,750)*
Unit cost of disposing hazardous power plant waste materials. AC is removed and processed to remove the mercury.

Power Cost: *Number, units* =$/MW-Hr *(e.g., 25)*
Unit cost of power the plant charges for running auxiliary equipment.

Mercury By-Product Cost: *Number, units* =$/ton *(e.g., 50)*
Unit cost of recovered mercury that could be sold in the marketplace.

1.1.4 Technical Model Results Sheet

The purpose of this sheet is to document the case study input data for the power plant and the mercury control technology, as well as the results of the performance calculations from the Power Plant Combustion

Model Sheet. Up to twenty case studies can be simultaneously created and documented in the sheet. Two reference power plants are documented; additional changes to the reference plant design and operating conditions can be made in this sheet in order to modify plant performance.

For the power plant definition, the sheet uses the input data from the Application Input Sensitivity Sheet and combines it with the reference plant data to create a specific plant for each case study. For example, if the high sulfur power plant gross power rating is input as 900 MWe in the input sensitivity sheet, then this overrides the reference plant rating of 541.9 MWe; plant auxiliary power is scaled accordingly. Sheet data for the reference plants should not be changed unless modifications are needed to simulate a different plant. For example, if a different net heat rate were desired, then the reference plant value would need to be replaced with a new value.

The mercury control data inputs are taken directly from both the *Input Sensitivity Sheet* and the *Hg Control Performance Models Sheet* and are listed for the sake of documentation and use by other parts of the spreadsheet.

Calculated power plant performance results from the Power Plant Combustion Model Sheet are returned to this sheet for documentation and use by the sheet to calculate specific performance results for the mercury control technology.

This sheet also uses results returned from the Combustion Model Sheet to calculate the flue gas acid dew point. This is an important design parameter given the significant influence of temperature on sorbent-based mercury control. While test data indicates that lower temperatures enhance mercury capture from the flue gas, reducing the gas temperature (via water injection) must be limited to a specified temperature approach to the acid dew point. Maintaining the gas temperature at such an increment will help prevent corrosion within the ductwork and particulate control devices. The sulfuric acid dew point calculation is based on the following algorithms:

$$1000/Tdp = 2.276\text{-}0.0294*\ln(PH_2O)\text{-}.0858*\ln(PH_2SO_4) + 0.0062*\ln(PH_2O)*\ln(PH_2SO_4)$$

Where,

Tdp = Acid Dew Point
PH_2O = Partial pressure of water in the flue gas
PH_2SO_4 = Partial pressure of sulfuric acid in the flue gas

The dew point is in degree K and partial pressures in mm Hg.

For example, if a flue gas contains 12 % volume of water vapor and 0.02 % volume SO_2 and say 2 % of SO_2 converts to SO3, compute the sulfuric acid dew point.

Gas pressure = 10 in wg or (10/407) =0.02457 atmg or 1.02457 atma.
PH_2O =0.12 * 1.02457 * 760 = 93.44 mm Hg.
$\ln(PH_2O)$ = 4.537
$PSO_3 = PH_2SO_4$.
PSO_3 = 0.02 * .0002 * (64/80) * 760 * 1.02457 = 0.0024917
$\ln(SO_3)$ = -6
Note that 2 % conversion is on weight basis and hence we multiplied and divided by the molecular weights of SO_2 and SO_3 in the above calculation.

1000/Tdp = 2.276 - 0.0294 * 4.537 + 0.0858 * 6-0.0062 * 4.537 * 6 = 2.489
Or Tdp=402 K or 129 C or 264 F

The percent conversion of SO_2 to SO_3 is calculated in the Combustion Model Sheet based on an algorithm that accounts for the sulfur in the coal and specific ash constituents (Fe_2O_3).

1.1.5 Combustion Calculations Sheet

The purpose of this sheet is to take the power plant case study design and operating data from the Technical Model Results Sheet and calculate the power plant technical performance parameters, such as combustion gas constituent flows and total gas flows at strategic boiler locations (e.g., after the air heater). Also, if flue gas cooling via water injection is specified by the user (by specifying a flue gas temperature lower than the reference plant's post air heater temperature), then this sheet will calculate the quantity of water required via energy balance calculations. This sheet also contains the coal analysis data described previously. The coal types are Illinois #6, Wyoming PRB, Texas Lignite, Utah Bituminous (LS), Appalachian (HS), Pittsburgh #8, and bituminous process derived fuel (LS). Detailed analysis data for each coal can be found within cell range AE61 to AP141.

1.1.6 Capital Cost Model Sheet

The Capital Cost Model Sheet makes use of the power plant and mercury control performance data to calculate the capital costs associated with a case study's mercury control design configuration. The costing currently covers the following equipment sections:

Spray Cooling Water System
Sorbent Injection System
Sorbent Recycle System
Pulse-Jet Baghouse and Accessories
Ash/Spent Sorbent Handling System
Continuous Emissions Monitoring System (CEMS) Upgrade

A total mercury control system cost is calculated from the following cost components: 1) equipment, 2) related materials, 3) field and indirect labor, 4) sales tax, 5) base erected cost, 6) Engineering design, 7) process and project contingencies, and 8) general facilities. Maintenance costs are also calculated as a percentage of the bare erected cost (e.g., 2%). This sheet also contains an "Economic Master Table" in which a number of key costing parameters, such as contingency factors, can be changed and incorporated into the case study calculations. Twenty case studies can be handled simultaneously in this sheet.

1.1.7 System Economic Model Sheet

This sheet calculates mercury control system O&M, total system investment, total system capital requirement, and then levelizes the capital and O&M to establish single value for $/lb of mercury removed. Twenty case studies can be handled simultaneously in this sheet.

1.1.7.1 Mercury Control System O&M Costs

Operating Labor: cost of system operating and administrative personnel; unit labor rates and manpower requirements/shift are specified in the case study O&M table and can be specified independently for each case study.

Maintenance Labor: 40% of the total maintenance cost calculated in the Capital Cost Model Sheet

Maintenance Material: 60% of the total maintenance cost calculated in the Capital Cost Model Sheet

Administrative and Support Labor: Calculated as a percentage (labor overhead charge rate) of the sum of the operating and maintenance labor cost; overhead charge specified in the case study O&M table and can be specified independently for each case study.

Consumable values are taken from the Technical Model Results Sheet. The O&M cost consists of the following consumable components:

Water (for flue gas humidification), gallons/Hr: *unit cost = $/1000 gallons (e.g., 0.80), specified in case study table*

Sorbent (e.g., Activated Carbon), tons /Hr: *unit cost = $/ton (e.g., 1,100), specified in case study table*

Incremental Power, kW-Hr: *unit cost = $/MW-Hr (e.g., 30), specified in case study table*
Fan power accounts for the added pressure drop across the mercury control equipment, such as the fabric filter. Sorbent injection system power is required to transport the sorbent to the flue gas duct. Humidification system power is required to pump water to an injection grid in the ductwork.

Waste Disposal, tons/Hr: *unit cost = $/ton (e.g., 30), specified in case study table*
Waste AC is generated by the mercury control system. This mercury-laden AC must be disposed of or processed for mercury removal and recovery. This material can be disposed of with the rest of the plant's fly ash or it can be processed separately if deemed a hazardous material.

Mercury Byproduct, lb/Hr: *unit cost = $/ton (e.g., 30), specified in case study table*
If the spent AC is processed for recovery of mercury, then a by-product credit can be applied. This will be applied only if the user has designated the spent AC as hazardous waste material.

1.1.7.2 Total Mercury Control System Capital Requirement

The total calculated investment in the mercury control system includes the total capital investment calculated in the Capital Cost Model Sheet, interest during construction (AFUDC), and the following additional cost components:

Royalty allowance -- possible technology royalty charges may apply

Preproduction Costs -- covers the cost of operator training, equipment checkout, major modifications to equipment, extra maintenance, and inefficient use of consumables. Calculated as 1 month of fixed operating costs (O&M labor, admin and support labor, and maintenance materials); 1 month of variable operating costs (all consumables) at full capacity; and 2 % of the total system investment.

Inventory Capital -- value of initial inventory of activated carbon that is capitalized. This accounts for an initial storage supply of AC (e.g., 30 day supply).

Initial Catalysts and Chemicals Charge -- the initial cost of any catalysts or chemicals contained in the process equipment, but not in storage. Does not apply to the mercury control systems.

1.1.7.3 Levelized Cost of Mercury Control

The total cost of mercury control must account for the total capital requirement (expressed as $/kW) and the total operating and maintenance expenses (expressed as mills/kWh). In order to calculate an annualized cost that accounts for both of these, the capital requirement is annuitized via use of the "Levelized Carrying Charge Rate." The Levelized Carrying Charge Rate assumes a 30-year operating period and accounts for return on debt, return on equity, income taxes, book depreciation, property tax, and insurance payments. The Levelized Carrying Charge Rate is specified in this sheet in the section called "Financial Data-Factors." It is multiplied times the total system capital requirement to derive the annualized value and converted to units of mills/kWh based on the annual operating hours of the plant (capacity factor x 8,760 h/yr).

The first-year O&M costs that are calculated in this sheet are also levelized in order to account for both apparent and real escalation rates of labor, materials, and consumables over the expected operating time period (e.g., 30 years). A levelization factor is specified in this sheet in the section called "Financial Data-Factors." It is multiplied by the total O&M cost.

The levelized carrying charge and the levelized O&M are summed to yield a total annualized cost which is divided by the annual mercury removed in order to derive a unique cost of removal with units of $/ton mercury removed.

2. DOCUMENTATION OF REFERENCE POWER PLANTS USED IN MERCURY CONTROL MODEL.

Two (2) representative power plant applications are being employed in this study to investigate the mercury control costs for the baseline designs as well as parametric variations of these baseline plants. These plants are characterized as:

1) Plant firing high-sulfur, bituminous coal (Pgh #8) with low-NOx burners for NO_x control, cold-side ESP for particulate control, and a wet FGD system for SO_2 control.

2) Plant firing low-sulfur coal with low-NOx burners for NO_x control and a cold-side ESP for particulate control.

This section develops the basic specifications for each power plant variant: plant size, coal analysis, boiler performance parameters, flue gas mass/volumetric flow rates, gas constituents (including HCl), gas temperature/pressure profiles, total mercury concentration, and mercury speciation.

2.1 High Sulfur Power Plant Reference Case

The high sulfur reference coal (PC) plant design is comprised of a balanced draft, natural circulation steam generator, providing steam for a turbine generator set, condensing at 2.5 inches Hg absolute back pressure at the design point. The plant design and performance reflect current commercial practice in the U.S. utility industry. The turbine-generator is a tandem compound machine, with high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections. The LP turbine is comprised of two double flow sections exhausting downward into the condenser sections. The plant uses a 2400 psig/1000 ^{o}F/1000 ^{o}F single reheat steam power cycle. The boiler and the turbine are designed for a main steam flow of 3,621,006 pounds of steam per hour at 2520 pounds per square inch, gauge (psig) and 1000 ^{o}F at the superheater outlet, throttled to 2415 pounds per square inch, absolute (psia) at the inlet to the high pressure turbine. The cold reheat flow is 3,233,808 lb/hr of steam at 590 psia and 637 ^{o}F, which is reheated to 1000 ^{o}F before entering the intermediate pressure turbine section. The net plant output power, after plant auxiliary power requirements are deducted, is nominally 508 MWe. The overall net plant higher heating value (HHV) efficiency is nominally 36.8 percent. Refer to **Table 2-1** for the plant performance summary information.

Applicable Federal, State, and Local environmental standards relating to air, water, solid waste and noise have been designed into the high sulfur reference plant. Projected plant air emissions are identified in **Table 2-2**. The wet, limestone FGD system ensures an SO_2 emission rate of less than 0.371 lb/MMBtu (92% reduction). The use of low NO_x burner technology, combined with over fire air, results in NO_X emissions of less than 0.30 lb/MMBtu. The control or reduction of N_2O has not been addressed in this design because N_2O levels are presently unregulated. The flue gas scrubber is a wet limestone type system, with scrubbing and demisting occurring in the same vessel. An organic acid is added to the circulating reagent to enhance the scrubbing performance. Air is blown into the scrubber module sump to promote forced oxidation of the sulfite to sulfate. The gypsum byproduct is dried to a cake-like consistency in a train of centrifuges, and is ready to landfill.

TABLE 2-1
HIGH SULFUR PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, °F	1,000
Reheat Outlet Temperature °F	1,000
POWER SUMMARY	
3600 rpm Generator	
GROSS POWER, kWe (Generator terminals)	541,900
AUXILIARY LOAD SUMMARY, kWe	
Pulverizers	2,000
Primary Air Fans	1,840
Forced Draft Fans	1,350
Induced Draft	7,500
Seal Air Blowers	60
Main Feed Pump (Note 1)	2,400
Steam Turbine Auxiliaries	900
Condensate Pumps	1,100
Circulating Water Pumps	5,070
Cooling Tower Fans	2,400
Coal Handling	230
Limestone Handling & Reagent Prep.	1,160
FGD Pumps and Agitators	3,000
Ash Handling	2,000
Dewatering Centrifuges (FGD byproduct)	1,100
Precipitators	1,100
Soot Blowers (Note 2)	neg.
Miscellaneous Balance of Plant (Note 3)	2,000
Transformer Loss	1,300
TOTAL AUXILIARIES, kWe	34,100
Net Power, kWe	507,800
Net Efficiency, % HHV	36.8
Net Heat Rate, Btu/kWh (HHV)	9,279
CONDENSER COOLING DUTY, 10^6 Btu/hr	2,350
CONSUMABLES	
As-Received Coal Feed, lb/hr	378,550
Sorbent, lb/hr	46,790

Note 1 - Driven by auxiliary steam turbine, electric equivalent not included in total.
Note 2 - Soot blowing medium is boiler steam. Electric power consumption is negligible.
Note 3 - Includes plant control systems, lighting, HVAC, etc.

TABLE 2-2
HS PLANT AIR EMISSIONS - 65% CAPACITY FACTOR

	lb/MMBtu	Tons/Year
SO_X	0.46	5,880
NO_X	0.30	3,840
Particulate	0.01	125

The following indicates the state point conditions at various flue gas stream locations;

Flue gas mass flow rate, boiler exit	4,966,633 lb/hr (1,561,834 acfm)
Flue gas temperature at boiler exit	290 ^oF
Flue gas temperature at ESP exit	290 ^oF
Flue gas temperature at FGD exit	128 ^oF

The flue gas composition and temperatures at various points of the gas stream are detailed in **Table 2-3.** This data was calculated using the ACI Mercury Control Cost Model described in Section 3.

2.1.1 Plant Site Ambient Conditions

The plant site is assumed to be in the Ohio River Valley of western Pennsylvania/eastern Ohio/ northern West Virginia. The site consists of approximately 300 usable acres, not including ash disposal, within 15 miles of a medium sized metropolitan area, with a well established infrastructure capable of supporting the required construction workforce.

The site is within Seismic Zone 1, as defined by the Uniform Building Code, and the ambient design conditions will be:

Pressure	14.4 psia
Dry bulb temperature	6o ^oF
Dry bulb temperature range	(-) 10 to (+) 110 ^oF
Wet bulb temperature	52 ^oF

2.1.2 Fuel and Sorbent Composition

The plant performance will be based on the Pittsburgh #8 Coal and Greer limestone compositions and data listed in **Tables 2-4** and **2-5**. Unit start-up will use No.2 fuel oil.

TABLE 2-3
HIGH SULFUR (HS) REFERENCE POWER PLANT GAS STREAM DATA

Boiler & Plant Data Summary	PGH #8 (HS)
Btu Input Rate (MMBtu/h)	4,711.88
Coal Input Rate (tons/h)	188.337
Coal Mass-Energy Ratio (lb/MMBtu)	79.94
MMBtu/hr Out of Boiler	4,162.49
Flue Gas @ Economizer Outlet (SCFM/MMBtu)	12,503
Flue Gas @ Economizer Outlet (SCFM)	981,877
Wet Flue Gas @ Economizer Outlet (lb/h)	4,598,641
Wet Air Based on Economizer Outlet (SCFM)	934,407
Wet Air Based on Economizer Outlet (lb/h)	4,260,670
Total Air, % (Economizer Outlet)	120.0
Excess Air, % (Economizer Outlet)	20.0
Flue Gas @ Air Heater Outlet (SCFM/MMBtu)	13,753
Flue Gas @ Air Heater Outlet (SCFM)	1,080,065
Wet Flue Gas @ Air Heater Outlet (lb/h)	5,042,924
Wet Air Based on Air Heater Outlet (SCFM)	1,031,843
Wet Air Based on Air Heater Outlet (lb/h)	4,704,952
Wet Air Leakage @ Air Heater (SCFM)	97,436
Wet Air Leakage @ Air Heater (lb/h)	444,283
Equivalent Total Air, % (Air Heater Outlet)	132.5
Equivalent Excess Air, % (Air Heater Outlet)	32.5
Wet Flue Gas @ Air Heater Outlet (ACFM)	1,689,826
Air Heater Outlet Flue Gas Temperature, ^oF	290
Air Heater Outlet Pressure, inches Hg.	29.31
Fly Ash (ton/h)	15.48
Bottom Ash (ton/h)	3.87
Total Ash (ton/h)	19.35
NOTE: Standard Conditions = 60 ^oF, 29.92 inches Hg	

TABLE 2-4
GREER LIMESTONE ANALYSIS

	Dry Basis, %
Calcium Carbonate, $CaCO_3$	80.4
Magnesium Carbonate $MgCO_3$	3.5
Silica, SiO_2	10.32
Aluminum Oxide, Al_2O_3	3.16
Iron Oxide, Fe_2O_3	1.24
Sodium Oxide, Na_2O	0.23
Potassium Oxide, K_2O	0.72
Balance	0.43

TABLE 2-5
PITTSBURGH NO.8 COAL ANALYSIS

Constituent	Air Dry, %	Dry, %	As Received, %
Carbon	71.88	73.79	69.36
Hydrogen	4.97	4.81	5.18
Nitrogen	1.26	1.29	1.22
Sulfur	2.99	3.07	2.89
Ash	10.30	10.57	9.94
Oxygen	8.60	6.47	11.41
Total	100.00	100.00	100.00

	Dry Basis, %	As Received, %
Moisture	-----	6.00
Ash	10.57	9.94
Volatile Matter	38.20	35.91
Fixed Carbon	51.23	48.15
Total	100.00	100.00
Cl, ppm in Coal	650	
Hg, ppb in Coal	78 $\pm$ 24	
Sulfur	3.07	2.89
Btu Content	13,244	12,450
Moisture and Ash Free (MAF), Btu	14,810	

	Ash Analysis, %
Silica, SiO_2	48.1
Aluminum Oxide, AlO_3	22.3
Iron Oxide, Fe_2O_3	24.2
Titanium Dioxide, TiO_2	1.3
Calcium Oxide, CaO	1.3
Magnesium Oxide, MgO	0.6
Sodium Oxide, Na_2O	0.3
Potassium Oxide, K_2O	1.5
Sulfur Trioxide, SO_3	0.8
Phosphorous Pentoxide, P_2O_5	0.1
Total	100.5

	Ash Fusion Temperature, ^oF	
	Reducing Atmosphere	Oxidizing Atmosphere
Initial Deformation	2015	2570
Spherical	2135	2614
Hemispherical	2225	2628
Fluid	2450	2685

2.1.3 Air Quality Standards

The plant pollution emission requirements for the High Sulfur Reference Case reflect current environmental emissions standards for a plant sited in a non-attainment area with respect to ambient air standards for ozone. **Table 2-2** presents emissions for the plant without site sensitive NO_x reduction enhancements.

2.1.4 Flue Gas Acid Dew Point.1.4

Based on a flue gas SO_3 concentration of 22 ppm and a water concentration of 7.65% at the exit of the air heater, the acid dew point is estimated to be approximately 280 ^oF.

2.1.5 Mercury Emission Assumptions
Table 2-6, presented below, provides basic data for baseline and variant mercury emissions.

TABLE 2-6
MERCURY EMISSIONS DATA

Total Mercury Concentration ($\mu g/Nm^3$)	Total Mercury Emissions Rate (g/h)	Total Annual Mercury Release[1] (Kg/yr)
10 (Baseline)	18.35	104.4
3	5.5	31.3
30	55.05	313.2

1. Based on a 65% plant capacity factor.

2.2 Low Sulfur Power Plant Reference Case

The low sulfur reference pulverized coal (PC) plant design utilizes a balanced draft, natural circulation type, pulverized coal subcritical fired boiler, providing steam for a turbine generator set. The boiler design and performance reflect current commercial practice in the U.S. utility industry. The turbine-generator is a tandem compound machine, with high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections. The LP turbine is comprised of two double flow sections exhausting downward into the condenser sections. The low sulfur reference plant uses a 2400 psig/1000 ^oF/1000 ^oF single reheat steam power cycle. The boiler and the turbine are designed for a main steam flow of 2,734,000 pounds of steam per hour at 2520 psig and 1000 ^oF at the superheater outlet, throttled to 2415 psia at the inlet to the high pressure turbine. The cold reheat flow is 2,425,653 lb/hr of steam at 604 psia and 635 ^oF, which is reheated to 1000 ^oF before entering the intermediate pressure turbine section. The net plant output power, after plant auxiliary power requirements are deducted, is nominally 404 MWe. The overall net plant higher heating value (HHV) efficiency is nominally 39.1 percent. Refer to **Table 2-7** for the plant performance summary information.

The plant also is designed to meet applicable Federal, State, and Local environmental standards relating to air, water, solid waste and noise. The plant has baseline SO_2 emissions of about 0.70 lb/MMBtu, and it is designed to utilize in-duct spray drying of lime to provide a removal efficiency of 50%. Lime slurry is sprayed into the flue gas duct, where it dries and captures SO_2 as a particle. The particulate is then collected in the electrostatic precipitator for disposal. If placed in service, the FGD system results in a SO_2 emission rate of less than 0.35 lb/MMBtu; the current investigation assumes that the FGD system will not be in operation. The use of low NOx burner technology, combined with over-fire air, results in NO_x

emissions of less than 0.30 lb/MMBtu. The control or reduction of N_2O has not been addressed in this design because N_2O levels are presently unregulated.

The low Sulfur Case Reference plant achieves a net plant efficiency of 39.1%, which is an increase of over 6% above that achieved by the High Sulfur Reference plant (36.8%). This increase in efficiency is achieved although the units are virtually identical in terms of size, boiler selection, steam cycle configuration, heat sink, and other considerations. The net efficiency improvements are due to the following:

- The low sulfur reference auxiliary plant load is lower than the high sulfur plant's auxiliary load. This reduction occurs because of the reduced ID fan power requirements, which result from the elimination of the pressure losses due to a scrubber. In addition, elimination of the reagent and byproduct handling systems associated with a wet scrubber reduce the auxiliary load but is offset by the atomizing air compressors for the duct injection system.

- The low sulfur plant gas temperature leaving the boiler is set at 270 ^oF versus 290 ^oF for the high sulfur plant. This reduction in exhaust temperature, which improves the boiler efficiency, is feasible because of the low SO_2 concentrations in the gas leaving the boiler, and the gas passes directly into the duct injection system that is upstream of the ESP.

2.2.1 Plant Site Ambient Conditions

The plant site is assumed to be in the Ohio River Valley of western Pennsylvania/eastern Ohio/ northern West Virginia. The site consists of approximately 300 usable acres; not including ash disposal, within 15 miles of a medium sized metropolitan area, with a well established infrastructure capable of supporting the required construction workforce. The site is within Seismic Zone 1, as defined by the Uniform Building Code, and the ambient design conditions will be:

Pressure	14.4 psia
Dry bulb temperature	60 ^oF
Dry bulb temperature range	-10 to +110 ^oF
Wet bulb temperature	52 ^oF

TABLE 2-7
LOW SULFUR POWER PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, ^oF	1,000
Reheat Outlet Temperature	1,000
POWER SUMMARY	
3600 rpm Generator	
GROSS POWER, kWe (Generator terminals)	427,060
AUXILIARY LOAD SUMMARY, kWe	
Pulverizers	1,600
Primary Air Fans	1,410
Forced Draft Fans	1,020
Induced Draft	3,230
Seal Air Blowers	50
Main Feed Pump (Note 1)	8,660
Steam Turbine Auxiliaries	800
Condensate Pumps	800
Circulating Water Pumps	3,400
Cooling Tower Fans	1,800
Coal Handling	180
Limestone Handling & Reagent Prep.	230
Ash Handling	1,600
Atomizing Air compressors (Duct Injection)	2,700
Precipitators	900
Soot Blowers (Note 2)	neg.
Miscellaneous Balance OF Plant (Note 3)	2,000
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	22,740
Net Power, kWe	404,320
Net Efficiency, % HHV	39.1
Net Heat Rate, Btu/kWh (HHV)	8,726
CONDENSER COOLING DUTY, 10^6 Btu/h	1,722
CONSUMABLES	
As-Received Coal Feed, lb/h	299,204
Sorbent, lb/h	4,277

Note 1 - Driven by auxiliary steam turbine, electric equivalent shown.
Note 2 - Soot blowing medium is boiler steam. Electric power consumption is negligible.
Note 3 - Includes plant control systems, lighting HVAC, etc.

2.2.2 Fuel and Sorbent Composition

The plant performance will be based on a, sub-bituminous, western Powder River Basin (PRB) coal that has undergone a moisture reduction and stabilization process. The coal analysis and data are listed in **Tables 2-8** and **2-9**. Unit start-up will use No.2 fuel oil.

2.2.3 Air Quality Standards

The plant pollution emission requirements for the Low Sulfur Reference Case adhered to Federal and State control emission regulations. Although, some environmental regulations may apply on a site specific basis (National Environmental Policy Act, Endangered Species Act, National Historic Preservation Act, etc.) will not be considered in this project. The following ranges will generally cover most cases:

SO_x:	92 to 95% reduction
NO_x:	0.2 to 0.45 lb per MMBtu
Particulate:	0.015 to 0.03 lb per MMBtu
Opacity:	10 to 20 percent

2.2.4 Flue Gas Acid Dew Point.

Based on a flue gas SO_3 concentration of 0.5 ppm and a water concentration of 6.5% at the exit of the air heater, the acid dew point is estimated to be approximately 175 ^oF.

2.2.5 Mercury Emission Assumptions

Table 2-10 provides basic data for baseline and variant mercury emissions.

2.2.6 LS Reference Power Plant Gas Stream Data

The following indicates the state point conditions at various flue gas stream locations.

Flue gas mass flow rate, boiler exit	3,821,126 lb/hr (1,309,735 cfm)
Flue gas temperature at AH exit	270 ^oF
Flue gas temperature at ESP exit	270 ^oF

The flue gas composition and temperatures at various points of the gas stream are detailed in **Table 2-11.** This data was calculated using the MCPCM described in Section 1 and coal properties for a low sulfur processed derived PRB coal.

TABLE 2-8
TYPICAL PROCESSED PRB COAL ANALYSIS

Constituent	**Dry, %**	**As Received, %**
Moisture	-------	--------
Carbon	75.25	70.98
Hydrogen	3.46	4.00
Nitrogen	1.13	1.07
Sulfur	0.56	0.53
Ash	8.19	7.72
Oxygen	11.41	15.70
Total	100.00	100.00

	Dry Basis, %	**As Received, %**
Moisture	-----	4.83
Ash	8.19	7.72
Volatile Matter	27.00	25.72
Fixed Carbon	64.81	61.73
Total	100.00	100.00
Sulfur	0.56	0.53
Btu Content	12,389	11,791
Moisture and Ash Free (MAF), Btu Content	13,494	

	Ash Analysis, %
Silica, SiO_2	22.5
Aluminum Oxide, Al	13.8
Iron Oxide,	7.4
Titanium Dioxide, TiO_2	0.8
Calcium Oxide, MgO	26.6
Magnesium Oxide, MgO	5.9
Sodium Oxide, Na_2O	1.8
Potassium Oxide, K_2O	0.2
Sulfur Trioxide, SO_3	19.3
Phosphorous Pentoxide, P_2O_5	0.6
Strontium Oxide, SrO	0.4
Barium Oxide, BaO	0.6
Manganese Oxide, Mn_4	0.1
Total	**100.00**

Ash Fusion Temperature, ^oF

	Reducing Atmosphere	**Oxidizing Atmosphere**
Initial Deformation	2295	2395
Spherical	2300	2405
Hemispherical	2305	2415
	2310	2425

TABLE 2-9
COMPARISON OF FEED COAL AND MODIFIED COAL BASIS

	Feed Coal	Process Derived Fuel
Heating Value (Btu/lb)	12,740	13,840
Carbon (%)	73.4	84.0
Hydrogen (%)	5.5	3.6
Nitrogen (%)	1.1	1.3
Volatiles (%)	47.0	32.0

TABLE 2-10
MERCURY EMISSIONS DATA

Total Mercury Concentration ($\mu g/Nm^3$)	Total Mercury Emissions Rate (g/Hr)	Total Annual Mercury Release[1] (Kg/Yr)
10 (Baseline)	13.8	78.5
3	3.5	23.5
30	138	235.5

1. Based on a 65% plant capacity factor.

TABLE 2-11
LS REFERENCE POWER PLANT GAS STREAM DATA

Boiler & Plant Data Summary	LS PDF (LS)
Btu Input Rate (MMBtu/h)	3,528.10
Coal Input Rate (tons/h)	150.739
Coal Mass-Energy Ratio (lb/MMBtu)	85.45
MMBtu/hr Out of Boiler	3,119.59
Flue Gas @ Economizer Outlet (SCFM/MMBtu)	12,656
Flue Gas @ Economizer Outlet (SCFM)	744,192
Wet Flue Gas @ Economizer Outlet (lb/h)	3,518,066
Wet Air Based on Economizer Outlet (SCFM)	710,817
Wet Air Based on Economizer Outlet (lb/h)	3,241,152
Total Air, % (Economizer Outlet)	120.0
Excess Air, % (Economizer Outlet)	20.0
Flue Gas @ Air Heater Outlet (SCFM/MMBtu)	13,795
Flue Gas @ Air Heater Outlet (SCFM)	811,169
Wet Flue Gas @ Air Heater Outlet (lb/h)	3,821,126
Wet Air Based on Air Heater Outlet (SCFM)	777,281
Wet Air Based on Air Heater Outlet (lb/h)	3,544,213
Wet Air Leakage @ Air Heater (SCFM)	66,464
Wet Air Leakage @ Air Heater (lb/h)	303,061
Equivalent Total Air, % (Air Heater Outlet)	131.2
Equivalent Excess Air, % (Air Heater Outlet)	31.2
Wet Flue Gas @ Air Heater Outlet (ACFM)	1,309,735
Air Heater Outlet Flue Gas Temperature, ^oF	314
Air Heater Outlet Pressure, inches Hg.	29.31
Fly Ash (ton/h)	9.83
Bottom Ash (ton/h)	2.46
Total Ash (ton/h)	12.28

NOTE: Standard Conditions = 60 ^oF, 29.92 inches Hg

3. Bituminous and Subbituminous Coals Used in Mercury Control Model Runs

EPA's mercury control technology application matrix cites three different coals for the model runs. The purpose of this section is to identify and document these three coals.

The two bituminous coals are from West Virginia – ultimate analysis and ash analysis data were obtained from the USGS Coal Quality Database. The high sulfur coal has a 3% sulfur content (by weight) and a HHV of 12,721 Btu/Lb, while the other has a 0.6% S content (by weight) and a HHV of 14,224 Btu/Lb.

The subbituminous coal is from Wyoming's Powder River Basin (PRB) and was already contained in the model's coal library. Data originally came from EPRI's FGD Cost Program. This coal has a coal sulfur content of 0.5% (by weight) and a HHV of 8,335 Btu/Lb.

TABLE 3-1
Bituminous and Subbituminous Coals Used in Mercury Control Model Runs

	WYOMING PRB (LS)	E. Bituminous (HS)	E. Bituminous (LS)
COAL ULTIMATE ANALYSIS (ASTM, as received, weight percent)			
Moisture	30.40%	3.10%	2.20%
Carbon	47.85%	69.82%	78.48%
Hydrogen	3.40%	5.00%	5.50%
Nitrogen	0.62%	1.26%	1.30%
Chlorine	0.03%	0.12%	0.12%
Sulfur	0.48%	3.00%	0.60%
Ash	6.40%	9.00%	3.80%
Oxygen	10.82%	8.70%	8.00%
TOTAL	100.00%	100.00%	100.00%
Mott Spooner HHV (Btu/lb)	8,335	12,721	14,224
Acid Dew Point, ^{o}F	224	215	292

COAL ASH ANALYSIS	WYOMING PRB (LS)	E. Bituminous (HS)	E. Bituminous (LS)
SiO_2	31.60%	29.00%	51.00%
Al_2O_3	15.30%	17.00%	30.00%
TiO_2	1.10%	0.74%	1.50%
Fe_2O_3	4.60%	36.00%	5.60%
CaO	22.80%	6.50%	4.20%
MgO	4.70%	0.83%	0.76%
Na_2O	1.30%	0.20%	1.40%
K_2O	0.40%	1.20%	0.40%
P_2O_5	0.80%	0.22%	1.80%
SO_3	16.60%	7.30%	2.60%
Other Unaccounted for	0.80%	1.01%	0.74%
TOTAL	100.00%	100.00%	100.00%

4. COST ESTIMATION BASIS

4.1 Introduction

This section defines the methodology used to estimate capital and O&M costs within the NETL Mercury Control Performance and Cost Model. Two different spreadsheets within the model provide for cost estimation. The **Capital Cost Model Sheet** makes use of the power plant and mercury control performance data to calculate the capital costs associated with a case study's mercury control design configuration. The costing covers the following equipment sections:

- **Spray Cooling Water System** (*Equipment: water storage tank, pumps, transport piping, and injection grid with nozzles, and control system*)

- **Solid Sorbent Storage and Injection System** (*Equipment: silo pneumatic loading system, storage silos, hoppers, blowers, transport piping, control system*)

- **Sorbent Recycle System** (*Equipment: hoppers, blowers, transport piping, control system*)

- **Pulse-Jet Fabric Filter and Accessories** (*Equipment: pulse-jet FF, filter bags, ductwork, dampers, and MCCs and instrumentation and PLC controls for baghouse operation. Excludes Ash Removal System, power distribution and power supply, and distributed control system*)

- **Sorbent Disposal System** (*Equipment: hoppers, blowers, transport piping, control system*)

- **CEMS Upgrade**

- **Flue Gas Desulfurization (FGD) System** (cost algorithms are currently not provided)

- **FGD System Enhancements** (cost algorithms are currently not provided)

- **Circulating Fluidized Bed Absorber System** (cost algorithms are currently not provided)

A total mercury control system cost is calculated from the following cost components: 1) equipment, 2) related materials, 3) field and indirect labor, 4) sales tax, 5) engineering and home office fees, 6) process and project contingencies, 7) retrofit factors, and 9) general facilities. Maintenance costs are also calculated as a percentage of the bare erected cost (e.g., 2%). Section 4.2 fully describes the methodology used to estimate the total installed retrofit capital cost. Section 4.3 defines specific algorithms used calculate specific equipment and installation labor costs.

The **System Economic Model Sheet** calculates mercury control system O&M, total system investment, total system capital requirement, and then levelizes the capital and O&M to establish single value for $/lb of mercury removed. Twenty case studies are handled simultaneously in this sheet. Sections 4.4 and 4.5 fully describe the methodology used to estimate these costs.

4.2 Capital Cost Estimation Basis

The cost of each equipment section, as identified in Section 4.1, is estimated according to the following procedure:

Bare Installed Retrofit Cost = (*Process Equipment + Related Field Materials + Field Labor + Indirect Field Costs + Sales Tax)* x *Retrofit Factor*

Equipment, field materials and field labor are specified via algorithms.

Indirect field costs are calculated as percentage of field labor (**7%** currently specified).
Sales tax is calculated as a percentage of the sum of the four cost elements (**0%** currently specified)
Retrofit Factor (accounts for retrofit difficulty) = **1.15** (Specified by EPA on 4/4/00)

Engineering & Home Office Overhead/Fees = *Bare Installed Retrofit Cost* x E&HO Percentage

EH&O Percentage = **10%** (Specified by EPA on 4/4/00)

Process Contingency = *Bare Installed Retrofit Cost* x *Process Contingency Percentage*

Process Contingency Percentage = **5%** (Specified by EPA on 4/4/00)

Project Contingency = (*Bare Installed Retrofit Cost* + *Engineering & Home Office Overhead/Fees* + Process Contingency) x *Project Contingency Percentage*

Project Contingency Percentage = **15%** (Specified by EPA on 4/4/00)

Total Cost of Each Equipment Section = *Bare Installed Retrofit Cost* + *Engineering & Home Office Overhead/Fees* + *Process Contingency* + *Project Contingency*

The total capital cost of the mercury control system is calculated to include the sum of all equipment sections and the total cost of general facilities as follows:

General Facilities Cost = (*Bare Installed Retrofit Cost* x *General Facilities Percentage*

General Facilities Percentage = **5%** (Specified by EPA on 4/4/00)
Project Contingency Percentage defined above

Total Control Capital Cost = Sum of Equipment Section Total Costs + General Facilities Cost

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4.3 Equipment and Installation Labor Cost Estimation

This section of the memo defines the equipment cost algorithms used in the Capital Cost Model Sheet. Each equipment section is defined separately below. Costs are updated from their baseline year values via use of the Chemical Engineering Annual Plant Index (CEI). The costing algorithms relate to a December 1998 baseline for which the CI value equals 389.5. The ratio of the current index value (e.g., December 1999) and the baseline value therefore yields a cost inflator that adjusts control costs to the specified year.

4.3.1 Spray Cooling Water System

<u>Process Equipment (x $1000), $E</u>

$\$E = 1900 \times (GPM/215)^{0.65} \times CEI/389.5$

GPM = Water flow in gallons/minute

<u>Field Materials (x $1000), $FM</u>

$\$FM = 1700 \times (GPM/215)^{0.65} \times CEI/389.5$

Field Labor (x \$1000), \$FL

$\$FL = 1500 \times (GPM/215)^{0.65} \times CEI/389.5$

Indirect Field Costs (x \$1000), \$IF

$\$IF = \$FL \times 0.07$

Bare Installed Cost (x \$1000) = \$E + \$FM + \$FL + \$IF

Example: GPM = 27.4 gpm (Cools flue gas from 290 F to 270 F, 472 MWe,net)
CEI = 399.7 (November 1999)

Bare Installed Cost (x \$1000) = 511 + 457+ 404 + 28 = 1,611 or \$3.41/kW

4.3.2 Solid Sorbent Injection System

Process Equipment (x \$1000), \$E

$\$E = 400 \times ((SF \times 1000/454)/5486)^{0.65} \times CEI/389.5$

SF = Sorbent Feed, Kg/Hr

Field Materials (x \$1000), \$FM

$\$FM = 900 \times ((SF \times 1000/454)/5486)^{0.65} \times CEI/389.5$

Field Labor (x \$1000), \$FL

$\$FL = 2600 \times ((SF \times 1000/454)/5486)^{0.65} \times CEI/389.5$

Indirect Field Costs (x \$1000), \$IF

$\$IF = \$FL \times 0.07$

Bare Installed Cost (x \$1000) = \$E + \$FM + \$FL + \$IF

Example: SF = 157 Kg/Hr (Based on 3.73 lb/MMacf, 472 MWe,net)
CEI = 399.7 (November 1999)

Bare Installed Cost (x \$1000) = 68+ 153 + 442 + 31 = 799 or \$1.69/kW

4.3.3 Sorbent Recycle System

Process Equipment (x \$1000), \$E

$\$E = 1200 \times (RR/13) \times CEI/389.5$

RR = Recycle (sorbent and ash), Tons/Hr

Field Materials (x \$1000), \$FM

$FM = $E

<u>Field Labor (x $1000), $FL</u>

$FL = $E

<u>Indirect Field Costs (x $1000), $IF</u>

$IF = $FL x 0.07

Bare Installed Cost (x $1000) = $E + $FM + $FL + $IF

4.3.4 Pulse-Jet Fabric Filter and Accessories

<u>Process Equipment (x $1000), $E</u>

$\$E = 4800 \times ((GFR/ACR)/84{,}326))^{0.80} \times CEI/389.5$

GFR = Flue Gas Flow Rate, acfm
ACR = PJFF air/cloth ratio, $ft^3/min/ft^2$

<u>Field Materials (x $1000), $FM</u>

$\$FM = 500 \times ((GFR/ACR)/84{,}326))^{0.80} \times CEI/389.5$

<u>Field Labor (x $1000), $FL</u>

$\$FL = 2700 \times ((GFR/ACR)/84{,}326))^{0.80} \times CEI/389.5$

<u>Indirect Field Costs (x $1000), $IF</u>

$IF = $FL x 0.07

Bare Installed Cost (x $1000) = $E + $FM + $FL + $IF

Example: GFR = 1,547,360 acfm (Based on 472 MWe,net)
ACR = 10 $ft^3/min/ft^2$
CEI = 399.7 (November 1999)

Bare Installed Cost (x $1000) = 8,006+ 834 + 4,503 + 315 = 15,707 or $33/kW

4.3.5 Sorbent Disposal System

<u>Process Equipment (x $1000), $E</u>

$E = 100 x (DS/6) x CEI/389.5

DS = Disposal Solids (spent sorbent and ash), Tons/Hr

<u>Field Materials (x $1000), $FM</u>

$FM = 2 x $E

<u>Field Labor (x $1000), $FL</u>

$FL = 6 x $E

<u>Indirect Field Costs (x $1000), $IF</u>

$IF = $FL x 0.07

Bare Installed Cost (x $1000) = $E + $FM + $FL + $IF

4.3.6 CEMS Upgrade

<u>Process Equipment (x $1000), $E</u>

$E = 10 x $(MW/290.4)^{0.75}$ x CEI/389.5

MW = Power Plant Application Net Capacity, MWe,net

<u>Field Materials (x $1000), $FM</u>

$FM = 0

<u>Field Labor (x $1000), $FL</u>

$FL = 1.2 x $E

<u>Indirect Field Costs (x $1000), $IF</u>

$IF = $FL x 0.07

Bare Installed Cost (x $1000) = $E + $FM + $FL + $IF

4.4 Mercury Control System O&M Cost Estimation

4.4.1 O&M Cost Parameters

The O&M cost consists of the following labor and maintenance components:

Operating Labor: cost of system operating and administrative personnel; unit labor rates and manpower requirements/shift are specified in the case study O&M table and can be specified independently for each case study.

Maintenance Labor: 40% of the total maintenance cost calculated in the Capital Cost Model Sheet

Maintenance Material: 60% of the total maintenance cost calculated in the Capital Cost Model Sheet

Administrative and Support Labor: Calculated as a percentage (labor overhead charge rate) of the sum of the operating and maintenance labor cost; overhead charge specified in the case study O&M table and can be specified independently for each case study.

Consumable values are taken from the Technical Model Results Sheet. The O&M cost consists of the following consumable components:

Water (for flue gas humidification), gallons/Hr: *unit cost = $/1000 gallons (e.g., 0.80), specified in case study table*

Water quantity is taken from *Combustion Calculations Sheet*.

Sorbent (e.g., Activated Carbon), **tons /Hr**: *unit cost = $/ton (e.g., 1,100), specified in case study table*

Sorbent unit cost is an input in the *Application Input Sensitivity Sheet*

Incremental Power, kW-Hr: *unit cost = $/MW-Hr (e.g., 30), specified in case study table*

Fan power accounts for the added pressure drop across the mercury control equipment, such as the fabric filter. AC injection system power required to transport sorbent to flue gas duct. Humidification system power required to pump water to an injection grid in the ductwork.

Waste Disposal, tons/Hr: *unit cost = $/ton (e.g., 30), specified in case study table*

Waste sorbent is generated by the mercury control system. This mercury-laden sorbent must be disposed of or processed for mercury removal and recovery. For some design configurations, spent sorbent is captured with the fly ash and must be disposed of with the ash at the cost of ash disposal. For some design configurations, spent sorbent is collected with residual ash from the ESP. This material can be disposed of with the rest of the plant's fly ash or it can be processed separately if deemed a hazardous material.

The user specifies sorbent to be hazardous or non-hazardous in the *Application Input Sensitivity Sheet*. Unit costs for both conventional and hazardous waste disposal are also specified there.

Mercury Byproduct, lb/Hr: *unit cost = $/ton (e.g., 30), specified in case study table*

If the spent sorbent is processed for recovery of mercury, then a by-product credit can be applied. This will be applied only if the user has designated the spent AC as hazardous waste material.

4.4.2 Key O&M Cost Parameter Values

Labor:
Operating Labor Rate (base) -- **$25/Hr** (specified by EPA 4/4/00)
Total Operating Jobs – **0.833 OJ/Shift**

Consumables:
Water – **0.42 Mills/gallon** (specified by EPA 4/4/00)
Activated Carbon -- **$1/Kg** (specified by EPA 4/4/00)
Sorbent Storage Capacity – **30 days** (specified by EPA 4/4/00)
Electricity – **25 Mills/kW-Hr** (specified by EPA 4/4/00)
Waste Disposal (ash, AC, mercury) -- **$30/Ton**
Waste Disposal (Hazardous waste designation) -- **$1700/Ton**

Plant Capacity Factor – **65%** (specified by EPA 4/4/00)

4.5 Total Mercury Control System Capital Requirement

The total calculated investment in the mercury control system includes the total capital investment calculated in the Capital Cost Model Sheet, interest during construction (AFUDC), and the following additional cost components:

Royalty allowance -- possible technology royalty charges may apply

Preproduction Costs -- covers the cost of operator training, equipment checkout, major modifications to equipment, extra maintenance, and inefficient use of consumables. Calculated as 1 month of fixed operating costs (O&M labor, admin and support labor, and maintenance materials); 1 month of variable operating costs (all consumables) at full capacity; and 2 % of the total system investment.

Inventory Capital -- value of initial inventory of activated carbon that is capitalized. This accounts for an initial storage supply of AC (e.g., 30 day supply).

Initial Catalysts and Chemicals Charge -- the initial cost of any catalysts or chemicals contained in the process equipment, but not in storage. Does not apply to the mercury control systems.

4.5.1 Levelized Cost of Mercury Control

The total cost of mercury control must account for the total capital requirement (expressed as $/kW) and the total operating and maintenance expenses (expressed as mills/kW-Hr). In order to calculate an annualized cost that accounts for both of these, the capital requirement is annuitized via use of the "Levelized Carrying Charge Rate." The Levelized Carrying Charge Rate assumes a 30 year operating period and accounts for return on debt, return on equity, income taxes, book depreciation, property tax, and insurance payments. The Levelized Carrying Charge Rate is specified in this sheet in the section called "Financial Data-Factors." It is multiplied times the total system capital requirement to derive the annualized value and converted to units of mills/kW-Hr based on the annual operating hours of the plant (capacity factor x 8,760 hrs/yr).

The first-year O&M costs that are calculated in this sheet are also levelized in order to account for both apparent and real escalation rates of labor, materials, and consumables over the expected operating time period (e.g., 30 years). A levelization factor is specified in this sheet in the section called "Financial Data-Factors." It is multiplied by the total O&M cost.

The levelized carrying charge and the levelized O&M are summed to yield a total annualized cost which is divided by the annual mercury removed in order to derive a unique cost of removal with units of $/ton mercury removed.

4.5.2 Financial Parameter Values

Apparent General Escalation Rate – **2.9%/Year**
Royalty Allowance -- **$0**
Levelized Carrying Charge Rate – **0.133**
Federal Income Tax Rate – **34%**
Weighted Cost of Capital (after tax) – **9.4%**
Design and Construction – **1 year**
Book Life – **30 Years**

ATTACHMENT 2

Description of
Mercury Control Performance Algorithms Used in the National Energy Technology Laboratory Mercury Control Performance and Cost Model

Description of Mercury Control Performance Algorithms Used in the NETL Mercury Control Performance and Cost Model

The purpose of this report is to document the mercury control performance models that are currently incorporated into the NETL Mercury Control Cost Model. CMU staff based on available pilot- and full-scale data has developed these models, in the form of basic curve-fitting algorithms. The algorithms calculate the activated carbon feed (Lb/MMacf basis) required to achieve specified mercury removal efficiency for a particular control method (e.g., activated carbon injection upstream of an existing ESP). The performance prediction is based solely on control method, flue gas temperature and coal type (bituminous vs. subbituminous).

1. Mercury Control Retrofit Configurations: ESP-1, ESP-4, SD/ESP-1, and SD/ESP-2

Description: Activated carbon injected upstream of existing ESP. ESP-1 -- no flue gas temperature control, ESP-4 – flue gas temperature control via water injection.

1.1 Bituminous Coal

Coal Source: Eastern bituminous coal, West Virginia (< 1%S and 0.1% chlorine)

Data Sources:

PROJECT: ADA Technologies/Public Service Electric and Gas Company/EPRI -- Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration

Pilot-Scale Tests: 160 acfm slipstream from the 620 MWe Hudson Generating Station, Unit 2, opposed-fired furnace, Eastern bituminous coal from West Virginia (< 1%S and 0.1% chlorine), ESP SCA = 287 ft^2/Kacfm

Literature Source: Waugh, E., B. Jensen, L. Lapatnick, F. Gibbons, S. Sjostrom, J. Ruhl, R. Slye, and R. Chang, “Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration,” EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1997.
ICR Data: Baseline removal due to ash alone is from preliminary ICR report data compiled by Dennis Smith, DOE/NETL (5/1/00)

- Low sulfur bit coal ash removes constant 57% mercury
- Total removal is 57% from ash and 0 ==> 43% from ACI
- Baseline mercury removal (ash alone) is an average of 2 plants with 250F inlet and 4 plants with >300F inlet, both approximately 57%
- Correlation for 225F not included; no baseline removal available and temperature below H2SO4 dewpoint.

ICR Results and Pilot-Scale Test Results Combined:

- Mercury removal due to ash for both temperatures is 57% and is not a function of ACI
- Mercury removal due to ACI is not a function of ash but is a function of temperature
- The two removals can be combined: 57% from ash and between 0% and 43% from ACI

Algorithm 1: Incorporates ICR Results

$$\text{Hg Removal} = 100 - [a/(ACI+b)^c]$$

Coefficient	Flue Gas Temperature, ^oF		
	225	**250**	**275**
a	55.536	159.27	494.64
b	1.4351	3.6838	11.554
c	1	1	1
R^2 (error)	0.99	0.85	0.82
ACI Range (Lb/MMacf)	0 - 5	0 - 5	0 - 5

Algorithm 2: Excludes ICR Results

$$\text{Hg Removal} = 100 - [a/(ACI+b)^c]$$

Coefficient	Flue Gas Temperature, ^oF		
	225	**250**	**275**
a	128.69	370.98	1218.6
b	1.4284	3.6937	12.14
c	1	1	1
R^2 (error)	0.99	0.85	0.89
ACI Range (Lb/MMacf)	0 - 5	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

1.2 Subbituminous Coal

Coal Source: PRB Subbituminous coal
Data Source:

PROJECT: Pilot-Scale Carbon Injection for Mercury Control at Comanche Station

Pilot-Scale Tests: 600 acfm slipstream from the 350 MWe Comanche Station, Unit 2 PSCo, opposed-fired furnace, PRB coal from Belle Ayr mine, Pulse-Jet with A/C ratio = 12 ft/min, most fly ash removed upstream, Flue gas contained little HCl, 275 to 325 ppm SO_2 (@ 3% O_2 dry), 180 to 250 ppm NO_x (@ 3% O_2 dry)

Literature Source: AWMA 99-524, S.M. Haythornthwaite, J. Smith, G. Anderson, T. Hunt, M. Fox, R. Chang, T. Brown, 1999

Algorithm:

$$\text{Hg Removal} = 100 - [a/(ACI+b)^c]$$

Coefficient	Flue Gas Temperature, ^oF			
	230	**280**	**300**	**345**
a	1373.11	247.772	296.714	319.587
b	32.1071	3.3867	4.2911	3.6636
c	1	1	1	1
R^2 (error)	-	0.89	0.84	0.83
ACI Range (Lb/MMacf)	0 - 1	0 - 5	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

2. Mercury Control Retrofit Configurations: ESP-3, ESP-6

Description: Pulse-Jet FF (PJFF) retrofitted after existing ESP. Activated carbon injected upstream of PJFF. ESP-3 -- no flue gas temperature control, ESP-6 -- flue gas temperature control via water injection.

2.1 Bituminous Coal

Coal Source: Eastern bituminous coal, West Virginia (< 1%S and 0.1% chlorine)

Data Source:

PROJECT: ADA Technologies/Public Service Electric and Gas Company/EPRI -- Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration

Pilot-Scale Tests: 4,000 acfm slipstream from the 620 MWe Hudson Generating Station, Unit 2, opposed-fired furnace, Eastern bituminous coal from West Virginia (< 1%S and 0.1% chlorine), Pulse-jet FF installed downstream of cold ESP, A/C ratio = 12 ft/min, tests conducted with AC and fly ash

Literature Source: Waugh, E., B. Jensen, L. Lapatnick, F. Gibbons, S. Sjostrom, J. Ruhl, R. Slye, and R. Chang, "Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration," EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1997.

ICR Results and Pilot-Scale Test Results Combined:

- Mercury removal due to ash for both temperatures is 57% and is not a function of ACI
- Mercury removal due to ACI is not a function of ash but is a function of temperature
- The two removals can be combined: 57% from ash and between 0% and 43% from ACI

Algorithm 1: Incorporates ICR Results

$$\text{Hg Removal} = 100 - [a/(ACI+b)^c]$$

Coefficient	Flue Gas Temperature, ^oF		
	240	**285**	**285**
a	51.038	159.4	159.4
b	1.3194	3.5606	3.5606
c	1	1	1
R^2 (error)	0.73	0.66	0.66
ACI Range (Lb/MMacf)	0 - 5	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

Algorithm 2: Excludes ICR Results

$$\text{Hg Removal} = 100 - [a/(ACI+b)^c]$$

Coefficient	Flue Gas Temperature, ^oF	
	240	**285**
a	118.69	370.69
b	1.3194	3.5606
c	1	1
R^2 (error)	0.73	0.66
ACI Range (Lb/MMacf)	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

2.2 Subbituminous Coal

Coal Source: PRB Subbituminous coal

Data Source:

PROJECT: ADA Technologies/PS Colorado/EPRI/NETL – Pilot-Scale Demonstration of Dry Carbon-Based Sorbent Injection for Hg Control in Utility ESPs and FFs – Phase I

Pilot-Scale Tests: 600 acfm slipstream from the 350 MWe Comanche Station, Unit 2 PSCo, opposed-fired furnace, PRB coal from Belle Ayr mine, Pulse-Jet with A/C ratio = 12 ft/min, most fly ash removed upstream, Flue gas contained little HCl, 275 to 325 ppm SO_2 (@ 3% O_2 dry), 180 to 250 ppm NO_x (@ 3% O_2 dry)

Literature Source: Ebner, T., J. Ruhl, R. Slye, J. Smith, T. Hunt, R. Chang, and T. Brown, " Demonstration of Dry Carbon-Based Sorbent Injection for Mercury Control in Utility ESPs and Baghouses," EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1997.

Algorithm:

$$\text{Hg Removal} = 100 - [a/(ACI+b)^c]$$

Coefficient	Flue Gas Temperature, °F		
	250	**280**	**300**
a	4.2774	27.5595	148.0419
b	0.04793	0.31345	0.92051
c	1	1	1
R^2 (error)	0.99	0.8	0.96
ACI Range (Lb/MMacf)	0 – 3	0 – 3	0 – 3

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

3. Mercury Control Retrofit Configurations: FF-1, FF-2, SD/FF-1, and SD/FF-2

Description: Activated carbon injected upstream of existing reverse-gas baghouse. FF-1 -- no flue gas temperature control, FF-2 – flue gas temperature control via water injection.

3.1 Bituminous Coal

No data for bituminous coal applications.

3.2 Subbituminous Coal

Coal Source: PRB coal from Belle Ayr mine

Data Source:

PROJECT: ADA Technologies/PS Colorado/EPRI/NETL – Pilot-Scale Demonstration of Dry Carbon-Based Sorbent Injection for Hg Control in Utility ESPs and FFs

Pilot-Scale Tests: 600 acfm slipstream from the 350 MWe Comanche Station, Unit 2 PSCo, opposed-fired furnace, PRB coal from Belle Ayr mine, Flue gas contained little HCl, 275 to 325 ppm SO_2 (@ 3% O_2 dry), 180 to 250 ppm NO_x (@ 3% O_2 dry)

Literature Source: AWMA 99-524, S.M. Haythornthwaite, J. Smith, G. Anderson, T. Hunt, M. Fox, R. Chang, T. Brown, 1999

Algorithm:

Hg Removal = 100 – [a/(ACI+b)^c]

Coefficient	Flue Gas Temperature, ^oF		
	230	**275**	**330**
a	266.119	23.20196	27.9742
b	11.1359	0.43006	0.31913
c	1	1	1
R^2 (error)	0.03	0.88	0.87
ACI Range (Lb/MMacf)	0 - 1	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

4. Mercury Control Retrofit Configurations: WS-1

Description: Existing ESP for particulate control and wet FGD for SO_2 control.

4.1 Bituminous Coal

Coal Source: Bituminous coal
Data Source:
Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000

Methodology:

- Hg speciation for Bituminous coal: 70% oxidized, 30% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm for bituminous coal (Section 1.1)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

4.2 Subbituminous Coal

Coal Source: Subbituminous coal
Data Source:
Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Methodology:

- Hg speciation for subbituminous coal: 25% oxidized, 75% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm for subbituminous coal (Section 1.2)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

5. Mercury Control Retrofit Configurations: WS-2

Description: Existing SNCR for NOx control, existing ESP for particulate control and wet FGD for SO_2 control.

5.1 Bituminous Coal

Coal Source: Bituminous coal
Data Source:
Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Impact of SNCR: Not specified

Methodology:

- Hg speciation for Bituminous coal: 70% oxidized, 30% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm (Section 1.1)
- SNCR installation increases oxidized Hg by 0% (e.g., 70% total)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

5.2 Subbituminous Coal

Coal Source: Subbituminous coal
Data Source:
Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Impact of SNCR: Not specified
Methodology:

- Hg speciation for subbituminous coal: 25% oxidized, 75% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm for subbituminous coal (Section 1.2)
- SNCR installation increases oxidized Hg by 0% (e.g., 25% total)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

6. Mercury Control Retrofit Configurations: WS-3

Description: Existing SCR for NOx control, existing ESP for particulate control and wet FGD for SO_2 control.

6.1 Bituminous Coal

Coal Source: Bituminous coal
Data Source:
Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Impact of SCR: Mercury control phone meeting 4/28/2000
Methodology:

- Hg speciation for Bituminous coal: 70% oxidized, 30% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm (Section 1.1)
- SCR installation increases oxidized Hg by 35% (e.g., 94.5% total)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

6.2 Subbituminous Coal

Coal Source: Subbituminous coal
Data Source:
Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Impact of SCR: Mercury control phone meeting 4/28/2000
Methodology:

- Hg speciation for subbituminous coal: 25% oxidized, 75% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm for subbituminous coal (Section 1.2)
- SCR installation increases oxidized Hg by 35% (e.g., 33.75% total)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

7. Mercury Control Retrofit Configurations: ESP-7, Combined AC + Lime Sorbent

Description: Pulse-Jet FF (PJFF) retrofitted after existing ESP. Combined activated carbon/Lime sorbent injected upstream of PJFF.

7.1 Bituminous Coal

Coal Source: Bituminous coal

Data Source:
Butz, J.R., R. Chang, E.G. Waugh, "Use of Sorbents for Air Toxics Control in a Pilot-Scale COHPAC Baghouse," paper presented at the Air and Waste Management Association's 92nd annual meeting and exhibition, June 20-24, 1999, St. Louis, Mo.

Methodology:

- Assumes AC:Lime ratio = 2:19
- Assume 90%+ Hg Removal based on ADA Technologies tests at PSE&G
- 1- 4 lb/MMacf Sorbent Concentration yields 90-95% Hg Removal

ATTACHMENT 3

Summary of Mercury Control Cases Analyzed with National Energy Technology Laboratory Mercury Control Performance and Cost Model

Summary of Mercury Control Cases Analyzed with NETL's Mercury Control Performance and Cost Model

The purpose of this document is to summarize the mercury control cases evaluated with NETL's Mercury Control Performance and Cost Model.

1. Original Cases Designated by EPA

Table 1 identifies the original matrix of cases that were designated by EPA for evaluation. Of those designated in the table, the following model plant types were actually evaluated: 1, 4, 7, 8, 10, 13, 16, and 17. The others were not assessed due to lack of control performance data or similarity to another model plant type. Table 2 describes the mercury control retrofit scenario configurations used in Table 1.

2. EPA Evaluation Requirements

For each combination of model plant and pertinent mercury control technology (see Tables 1 and 2), EPA requested estimates of capital cost ($/kW), fixed O&M cost (mills/kWh), and variable O&M cost (mills/kWh) using the EPRI TAG methodology. These cost estimates were in 1999 constant dollars. EPA also designated the following analysis assumptions:

(1) Mercury removal of 50%, 60%, 70%, 80%, and 90% for each of the model plants;

(2) Flue gas temperature at activated carbon injection location of 150 C for cases without spray cooling (SC) and an approach to saturation of 10 degrees celsius (18 degrees F) for cases with SC;

(3) plant capacity factor of 65%;

(4) activated carbon cost of $1.0/kg;

(5) water cost of 0.42 mills/gallon;

(6) energy cost 25 mills/kWh;

(7) 30 days of sorbent storage;

(8) labor cost of $25/h; and

(6) other economic assumptions

- (i) general facilities – 5% of direct process capital (DPC)
- (ii) engineering and home office expense – 10% of DPC
- (iii) process contingency – 5% of DPC
- (iv) project contingency – 15% of DPC + (i) + (ii) + (iii)
- (v) pre-production cost – 2% of total plant investment (TPI)
- (vi) retrofit factor – 1.15
- (vii) fixed O&M – 1.5% of TPI

TABLE 1
ORIGINAL MERCURY CONTROL CASES DESIGNATED BY EPA

MODEL PLANT #	POWER PLANT SIZE (MW)	COAL		EXISTING PLANT EMISSION CONTROLS	MERCURY CONTROL(S)	CO-BENEFIT CASE(S) with
		Type[a]	**S%**			
1	975	Bit	3	ESP + FGD	ESP-1, ESP-3	SCR
2	975	Bit	3	FF + FGD	FF-1	SCR
3 Same as 1	975	Bit	3	HESP + FGD	HESP-1	SCR
4	975	Bit	0.6	ESP	ESP-4, ESP-6	SCR
5	975	Bit	0.6	FF	FF-2	SCR
6 Same as 4	975	Bit	0.6	HESP	HESP-1	SCR
7	975	Subbit	0.5	ESP	ESP-4, ESP-6	SCR
8	975	Subbit	0.5	FF	FF-2	SCR
9	975	Subbit	0.5	HESP	HESP-1	SCR
10	100	Bit	3	SD + ESP	SD/ESP-1	
11	100	Bit	3	SD + FF	SD/FF-1	
12	100	Bit	3	HESP + FGD	HESP-1	
13	100	Bit	0.6	ESP	ESP-4, ESP-6	
14	100	Bit	0.6	FF	FF-2	
15 Same as 13	100	Bit	0.6	HESP	HESP-1	
16	100	Subbit	0.5	ESP	ESP-4, ESP-6	
17	100	Subbit	0.5	FF	FF-2	
18 Same as 16	100	Subbit	0.5	HESP	HESP-1	

a. Bit = bituminous coal; Subbit = subbituminous coal.

Table 2
Mercury Control Technology Retrofit Scenarios

CASE	EXISTING EQUIPMENT	RETROFIT SCENARIO
ESP-1	Cold-side ESP (ESP)	ACI
ESP-3		ACI + PFF
ESP-4		SC + ACI
ESP-6		SC + ACI + PFF
ESP-7		SC + AC + lime + PFF
ESP-8		SC + ACI + CFBA
ESP-9		SC + AC + lime + CFBA
HESP-1	Hot-side ESP (HESP)	SC + ACI + PFF
FF-1	Fabric filter (FF)	ACI
FF-2		SC + ACI
FF-3		SC + AC + lime + PFF
SD/FF-1	Spray dryer (SD) + FF	ACI
SD/ESP-1	SD + ESP	ACI
WS-1	ESP + wet scrubber (WS)	
WS-2	SNCR + ESP + WS	
WS-3	SCR + ESP + WS	
SCR-SD-1	SCR + SD + FF	

3. Sensitivity Cases

In addition to the original cases described above, EPA also requested five sensitivity cases that are described below.

3.1 Power Plant Size

The purpose of this sensitivity analysis was to add 500 MWe cases for Model Plant Applications 1, 4, 7, 8.

This work was originally completed on 6/6/2000. The sensitivity runs were updated on 6-14-2000 to correct a programming error. The results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls**."

3.2 Mercury Control Operating Temperature

The purpose of this sensitivity analysis was to change the mercury control operating temperature to: Acid Dew Point (ADP) + 40 F for the following cases:

Plant 4, 500 MW
Plant 7, 500 MW
Plant 8, 500 MW
Plant 13, 100 MW
Plant 16, 100 MW
Plant 17, 100 MW

High sulfur cases are not impacted by the change. 975 MW cases were not run.

This work was originally completed on 6/6/2000. The sensitivity runs were updated on 6-14-2000 to correct a programming error. The results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls**."

3.3 COHPAC with Recycle

The purpose of this sensitivity analysis was to add 20% recycle of AC to the COHPAC-type mercury control scenarios (ESP-3 and ESP-6). This sensitivity applies only to retrofit scenarios ESP-3 and ESP-6. Mercury control temperature was set at ADP+18 F (ADP+40 F cases were not run) for the following model plant applications:

Plant 1, 500 MW (ESP-3)
Plant 4, 500 MW (ESP-6)
Plant 7, 500 MW (ESP-6)
Plant 13, 100 MW (ESP-6)
Plant 16, 100 MW (ESP-6)

This work was originally completed on 6/6/2000. The sensitivity runs were updated on 6-14-2000 to correct a programming error. The results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls**."

3.4 Addition of Ductwork to Increase Flue Gas Residence Time

The purpose of this sensitivity analysis was to add the capital cost of additional ductwork to the cost of mercury control for a specified model plant application. The model plant application that was selected was Plant 4, ESP-4, 500 MW. The following assumptions were used to complete this effort:

Application: Plant 4, ESP-4, Ductwork added upstream of ESP
Results presented with and without added ductwork
Plant sizes: 975, 500 and 100 MWe
Type of ductwork: carbon steel, polymer-lined, insulated (reflects a conservative selection of material)
Cost of ductwork: $134/sq ft
Installation labor: 0.8 hrs/sq ft
Number of ducts: 2
Duct gas velocity: 2800 ft/min
Retrofit factor: 1.3
Gas residence time in new duct: 1 second

This work was completed on 6/14/2000. The capital costing results indicate the following:

975 MW application: **$2.51/kW** for 2 ducts @ 47 feet long (22.3 ft x 22.3 ft)
500 MW application: **$3.50/kW** for 2 ducts @ 47 feet long (16 ft x 16 ft)
100 MW application: **$5.54/kW** for 2 ducts @ 47 feet long (10 ft x 10 ft)

The complete cost results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls" (Plant 4, W&WO Added Ductwork)**.

3.5 Use of a Combined AC/Lime Sorbent

The purpose of this sensitivity analysis was to assess the potential economic impact of using a sorbent consisting of AC and lime. The assumptions were:

Application: Model Plant 4, ESP-6, AC sorbent (50-90% Removal); Model Plant 4, ESP-7, AC-Lime Sorbent (90%+ removal)
Plant size: 500 MWe
AC sorbent Cost = $908/Ton
AC+Lime Sorbent Cost = $149/Ton, Assumes AC:Lime ratio = 2:19
ESP-7 Sensitivity Cases Assume 90%+ Hg Removal based on ADA Technologies tests at PSE&G
ESP-7 Sensitivity Cases run for 1, 2, 3, and 4 lb/MMacf Sorbent Concentration
ESP-6 Comparison Cases Run for 50, 60, 70, 80, 90% Hg Removal

The complete cost results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls" (Plant 4, 500 MW, Lime-AC Sorbent)**.

ATTACHMENT 4

Results of all Model Runs

Table 1. Mercury Control Technology Retrofit Configurations		
Mercury Control	**Existing Equipment (a,b)**	**Retrofit Technology (a)**
ESP-1	ESP	ACI
ESP-3		ACI + PFF
ESP-4		SC + ACI
ESP-6		SC + ACI + PFF
ESP-7		SC + AC + lime + PFF
ESP-8		SC + ACI + CFBA
ESP-9		SC + AC + lime + CFBA
HESP-1	HESP	
	SC + ACI + PFF	
FF-1	FF	ACI
FF-2		SC + ACI
FF-3		SC + AC + lime + PFF
SD/FF-1	SD + FF	ACI
SD/ESP-1	SD + ESP	ACI

a. ESP = cold-side electrostatic precipitator; HESP = hot-side electrostatic precipitator; FF= fabric filter; SD = spray dryer; ACI = activated carbon injection; PFF = polishing fabric filter.

b. Existing equipment may include wet scrubber and NOx controls such as selective catalytic reduction (SCR).

Table 2. Mercury Control Technology Applications and Cobenefits Definition

Model Plant #	Power Plant Size, MWe	Coal Type	Coal Sulfur Content, %S	Existing Controls	Mercury Controls	CoBenefit Case(s) with
1	975	Bit	3	ESP + FGD	ESP-1, ESP-3	SCR
2	975	Bit	3	FF + FGD	FF-1	SCR
3	975	Bit	3	HESP + FGD	HESP-1	SCR
4	975	Bit	0.6	ESP	ESP-4, ESP-6	
5	975	Bit	0.6	FF	FF-2	
6	975	Bit	0.6	HESP	HESP-1	
7	975	Subbit	0.5	ESP	ESP-4, ESP-6	
8	975	Subbit	0.5	FF	FF-2	
9	975	Subbit	0.5	HESP	HESP-1	
10	100	Bit	3	SD + ESP	SD/ESP-1	SCR
11	100	Bit	3	SD + FF	SD/FF-1	SCR
12	100	Bit	3	HESP + FGD	HESP-1	SCR
13	100	Bit	0.6	ESP	ESP-4, ESP-6	
14	100	Bit	0.6	FF	FF-2	
15	100	Bit	0.6	HESP	HESP-1	
16	100	Subbit	0.5	ESP	ESP-4, ESP-6	
17	100	Subbit	0.5	FF	FF-2	
18	100	Subbit	0.5	HESP	HESP-1	

a. Bit = bituminous coal; Subbit = subbituminous coal.
b. Mercury controls are shown in Table 1.

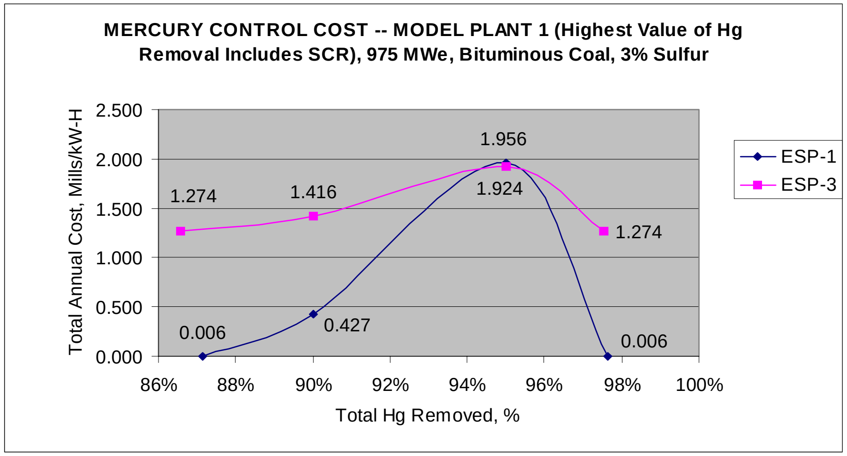
RESULTS FOR MODEL PLANTS 1 AND 4 **DATE: 5/22/00**
(Accounts for ICR Data Modification)
Comments:
1) Model Plant 1, ESP-1: Minimum Hg removal = 87% for ESP and FGD Combination with Eastern Bituminous Coals
2) Model Plant 1, ESP-1: Minimum Hg removal = 97.6% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
3) Model Plant 1, ESP-3: Minimum Hg removal = 86.6% for ESP and FGD Combination with Eastern Bituminous Coals
4) Model Plant 1, ESP-3: Minimum Hg removal = 97.6% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
5) Model Plant 4, ESP-4: Minimum Hg removal = 58% for ESP with Eastern Bituminous Coals
7) Model Plant 4, ESP-6: Minimum Hg removal = 61.3% for ESP with Eastern Bituminous Coals

See plot of results below table

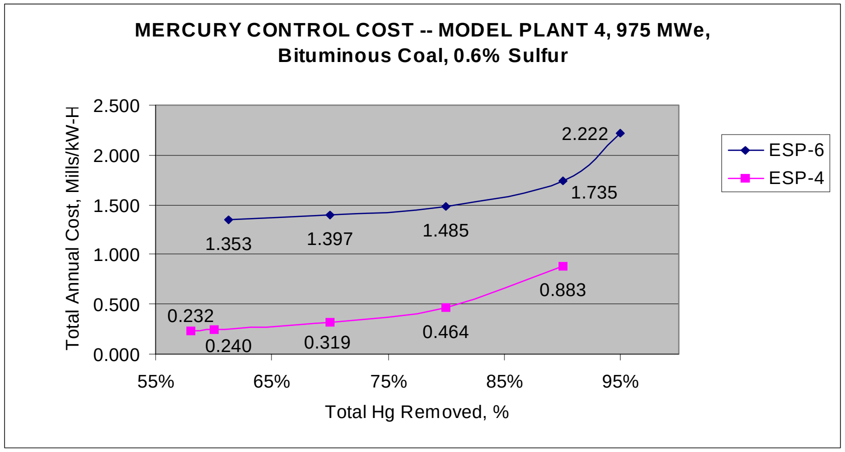
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	975	87.16%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.11	0.002	0.000	0.000	0.003	0.006
1	975	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	3.29	2.48	0.058	0.040	0.022	0.307	0.427
1	975	95.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	18.12	8.54	0.200	0.048	0.026	1.683	1.956
1	975	97.64%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.11	0.002	0.000	0.000	0.003	0.006
1	975	86.58%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	43.45	1.015	0.116	0.063	0.080	1.274
1	975	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	1.22	44.59	1.041	0.118	0.064	0.193	1.416
1	975	95.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	6.00	47.10	1.100	0.121	0.065	0.637	1.924
1	975	97.54%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	43.45	1.015	0.116	0.063	0.080	1.274
4	975	58.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	5.88	0.137	0.047	0.025	0.022	0.232
4	975	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.06	6.01	0.140	0.047	0.025	0.027	0.240
4	975	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.79	6.67	0.156	0.048	0.026	0.088	0.319
4	975	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.24	7.54	0.176	0.050	0.027	0.211	0.464
4	975	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	6.61	9.53	0.223	0.052	0.028	0.580	0.883
4	975	61.30%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	46.02	1.075	0.121	0.065	0.092	1.353
4	975	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.38	46.50	1.086	0.122	0.065	0.124	1.397
4	975	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.23	47.11	1.100	0.122	0.066	0.196	1.485
4	975	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	3.78	48.46	1.132	0.124	0.067	0.412	1.735
4	975	95.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	8.89	50.59	1.182	0.127	0.068	0.845	2.222

ECONOMIC RESULTS -- GRAPHICAL FORMAT

MODEL PLANT #1



MODEL PLANT #4



RESULTS FOR MODEL PLANTS 1 AND 4 (ADP+40) **DATE: 6/6/00**

(Utilizes Original Performance Algorithms -- Excludes ICR Data Modification)

Comments:

1) Model Plant 1, ESP-1: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals

2) Model Plant 1, ESP-1: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

3) Model Plant 1, ESP-3: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals

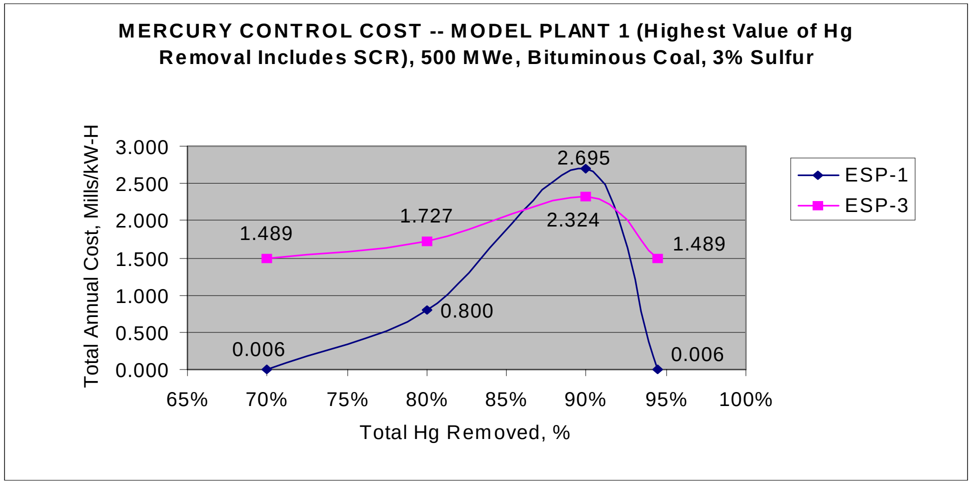
4) Model Plant 1, ESP-3: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

See plot of results below table

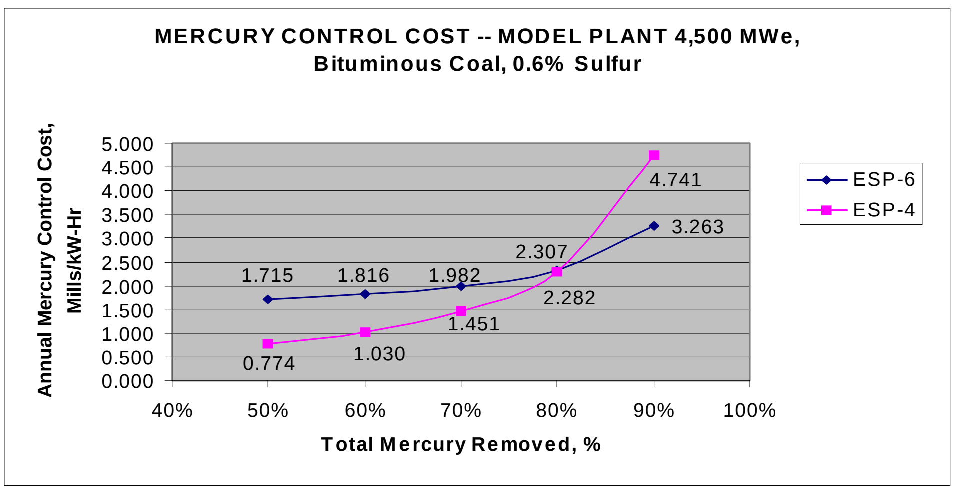
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	500	70.00%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	80.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	6.14	4.61	0.108	0.078	0.042	0.572	0.800
1	500	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	24.42	12.54	0.293	0.089	0.048	2.266	2.695
1	500	94.50%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	70.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	49.65	1.160	0.163	0.088	0.080	1.489
1	500	80.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	2.00	51.64	1.206	0.166	0.089	0.266	1.727
1	500	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	7.56	54.83	1.281	0.170	0.091	0.782	2.324
1	500	94.50%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	49.65	1.160	0.163	0.088	0.080	1.489
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	5.31	7.95	0.186	0.084	0.045	0.459	0.774
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	7.96	9.22	0.215	0.086	0.046	0.683	1.030
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	12.37	11.13	0.260	0.088	0.048	1.055	1.451
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.19	14.55	0.340	0.093	0.050	1.800	2.282
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	47.64	23.42	0.547	0.103	0.056	4.035	4.741
4	500	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	1.98	51.91	1.212	0.166	0.089	0.248	1.715
4	500	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	2.98	52.53	1.227	0.167	0.090	0.333	1.816
4	500	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	4.65	53.46	1.249	0.168	0.090	0.474	1.982
4	500	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	8.00	55.10	1.287	0.170	0.092	0.758	2.307
4	500	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	18.05	59.25	1.384	0.176	0.095	1.609	3.263

ECONOMIC RESULTS Ş GRAPHICAL FORMAT

MODEL PLANT # 1



MODEL PLANT # 4



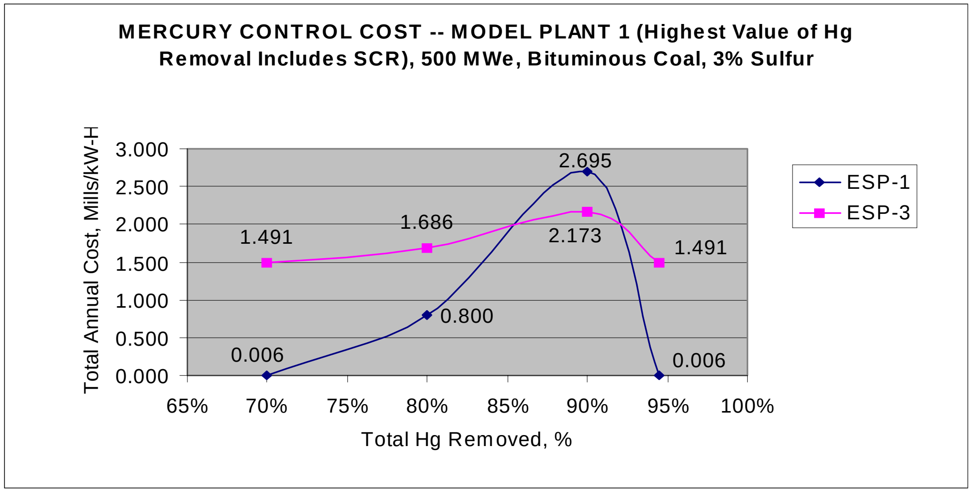
RESULTS FOR MODEL PLANTS 1 AND 4 (w Recycle for ESP-3 and ESP-6) **06/06/2000**
(Utilizes Original Performance Algorithms -- Excludes ICR Data Modification)
Comments:
1) Model Plant 1, ESP-1: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
2) Model Plant 1, ESP-1: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
3) Model Plant 1, ESP-3: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
4) Model Plant 1, ESP-3: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

See plot of results below table

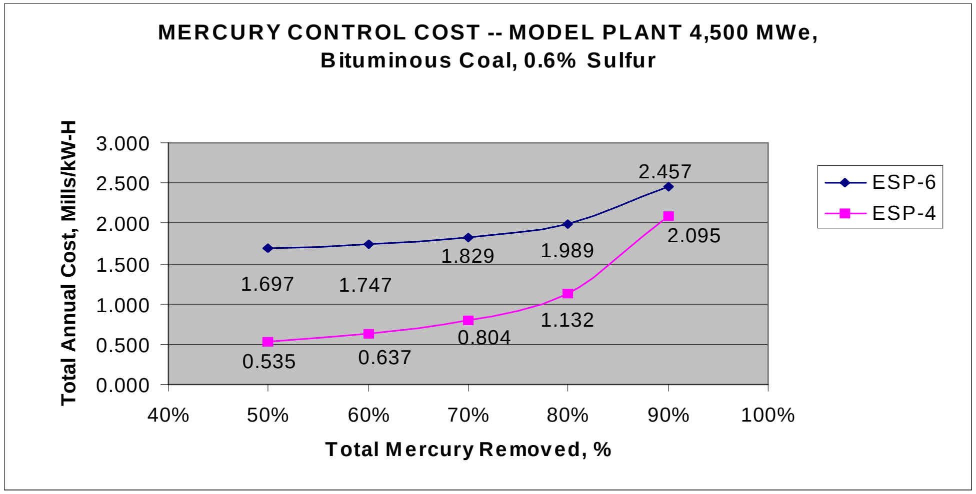
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	500	70.00%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	80.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	6.14	4.61	0.108	0.078	0.042	0.572	0.800
1	500	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	24.42	12.54	0.293	0.089	0.048	2.266	2.695
1	500	94.50%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	70.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	49.67	1.160	0.163	0.088	0.081	1.491
1	500	80.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	2.00	51.39	1.200	0.165	0.089	0.231	1.686
1	500	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	7.56	54.15	1.265	0.169	0.091	0.648	2.173
1	500	94.50%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	49.67	1.160	0.163	0.088	0.081	1.491
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	9.23	0.216	0.087	0.047	0.185	0.535
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	9.86	0.230	0.088	0.047	0.271	0.637
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	10.79	0.252	0.090	0.048	0.414	0.804
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	12.44	0.291	0.092	0.049	0.700	1.132
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	16.62	0.388	0.097	0.052	1.557	2.095
4	500	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	54.33	1.269	0.170	0.092	0.166	1.697
4	500	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.66	54.71	1.278	0.171	0.092	0.206	1.747
4	500	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	55.26	1.291	0.172	0.093	0.274	1.829
4	500	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	56.23	1.313	0.173	0.093	0.409	1.989
4	500	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	58.64	1.370	0.177	0.095	0.816	2.457

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 1



MODEL PLANT # 4



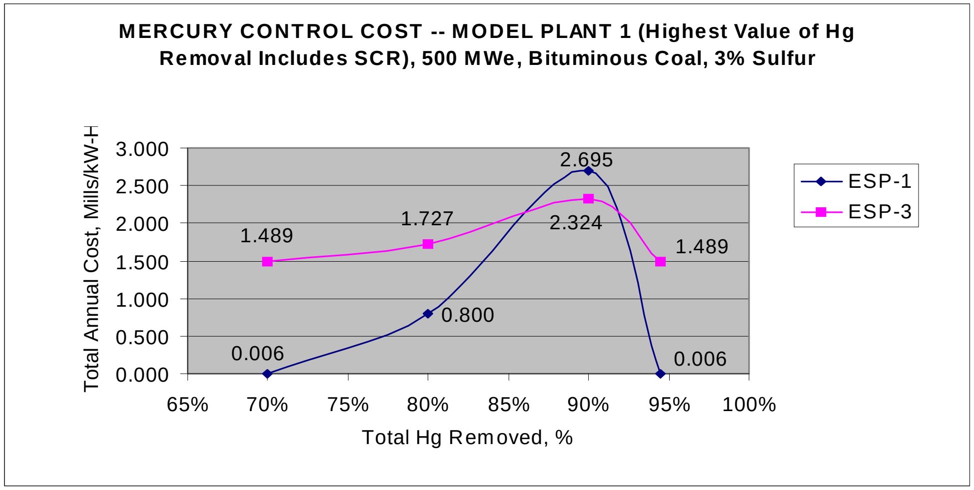
RESULTS FOR MODEL PLANTS 1 AND 4 06/05/2000
(Utilizes Original Performance Algorithms -- Excludes ICR Data Modification)
Comments:
1) Model Plant 1, ESP-1: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
2) Model Plant 1, ESP-1: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
3) Model Plant 1, ESP-3: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
4) Model Plant 1, ESP-3: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

See plot of results below table

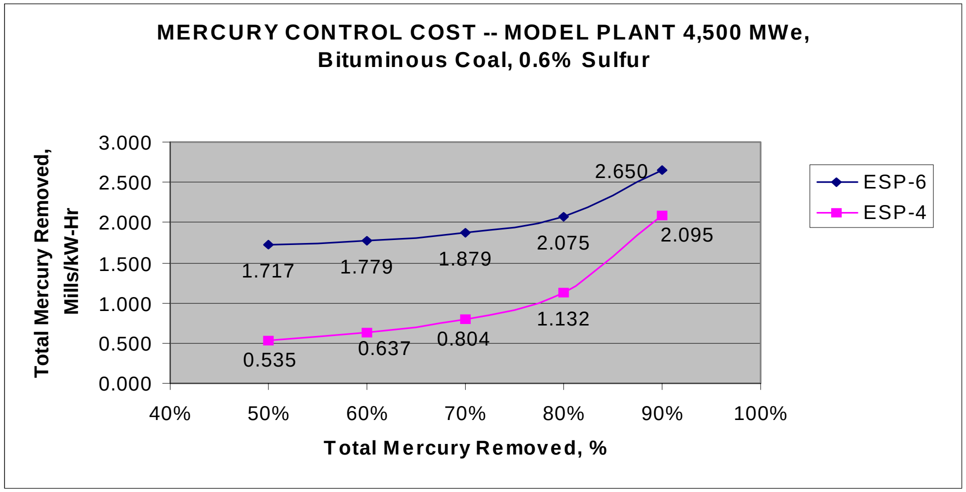
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	500	70.00%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	80.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	6.14	4.61	0.108	0.078	0.042	0.572	0.800
1	500	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	24.42	12.54	0.293	0.089	0.048	2.266	2.695
1	500	94.50%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	70.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	49.65	1.160	0.163	0.088	0.080	1.489
1	500	80.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	2.00	51.64	1.206	0.166	0.089	0.266	1.727
1	500	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	7.56	54.83	1.281	0.170	0.091	0.782	2.324
1	500	94.50%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	49.65	1.160	0.163	0.088	0.080	1.489
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	9.23	0.216	0.087	0.047	0.185	0.535
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	9.86	0.230	0.088	0.047	0.271	0.637
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	10.79	0.252	0.090	0.048	0.414	0.804
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	12.44	0.291	0.092	0.049	0.700	1.132
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	16.62	0.388	0.097	0.052	1.557	2.095
4	500	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	54.48	1.273	0.171	0.092	0.182	1.717
4	500	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.66	54.91	1.283	0.171	0.092	0.232	1.779
4	500	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	55.55	1.298	0.172	0.093	0.316	1.879
4	500	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	56.67	1.324	0.174	0.094	0.484	2.075
4	500	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	59.46	1.389	0.178	0.096	0.987	2.650

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 1



MODEL PLANT # 4



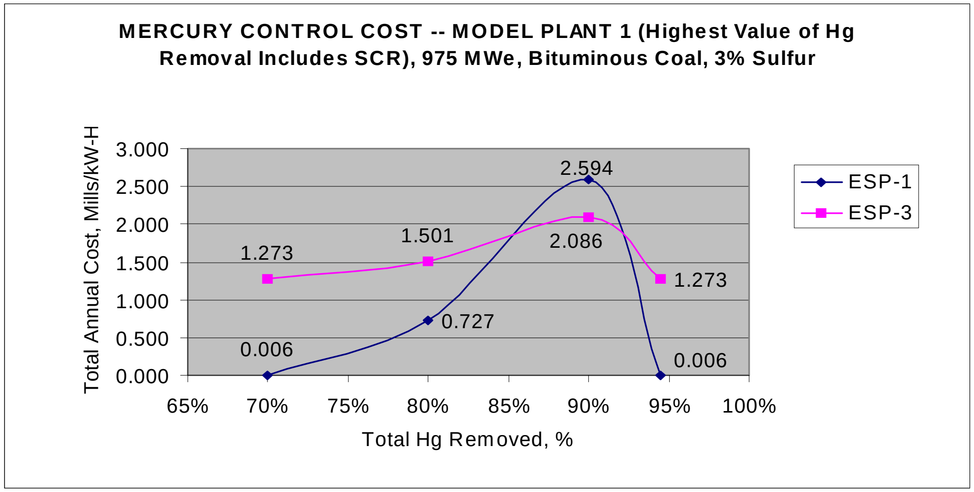
RESULTS FOR MODEL PLANTS 1 AND 4 **05/22/2000**
(Utilizes Original Performance Algorithms -- Excludes ICR Data Modification)
Comments:
1) Model Plant 1, ESP-1: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
2) Model Plant 1, ESP-1: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
3) Model Plant 1, ESP-3: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
4) Model Plant 1, ESP-3: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

See plot of results below table

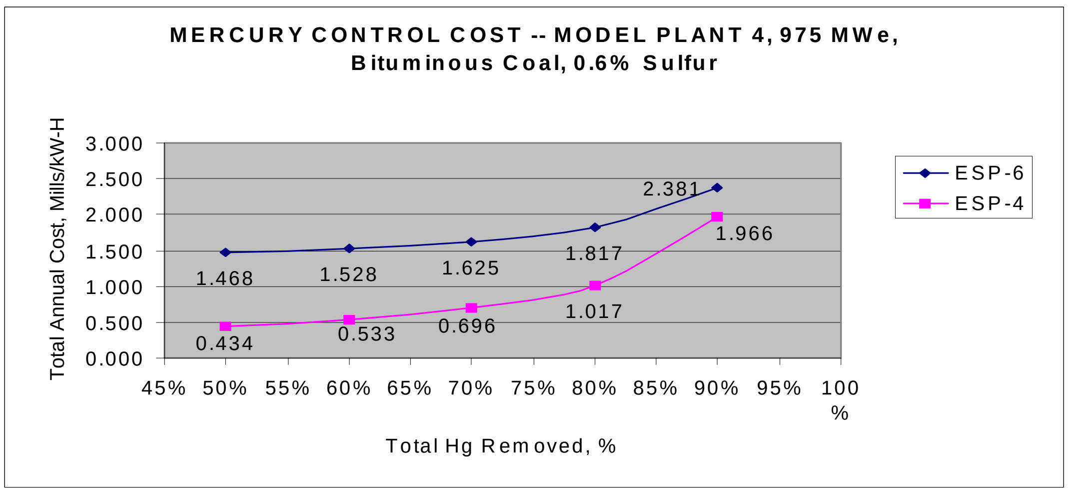
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	975	70.00%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.11	0.002	0.000	0.000	0.003	0.006
1	975	80.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	6.14	3.85	0.090	0.042	0.023	0.572	0.727
1	975	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	24.42	10.73	0.251	0.050	0.027	2.266	2.594
1	975	94.50%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.11	0.002	0.000	0.000	0.003	0.006
1	975	70.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	43.43	1.014	0.116	0.063	0.080	1.273
1	975	80.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	2.00	45.08	1.053	0.119	0.064	0.266	1.501
1	975	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	7.56	47.78	1.116	0.122	0.066	0.782	2.086
1	975	94.50%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	43.43	1.014	0.116	0.063	0.080	1.273
4	975	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	7.37	0.172	0.049	0.027	0.185	0.434
4	975	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	7.90	0.185	0.050	0.027	0.271	0.533
4	975	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	8.70	0.203	0.051	0.028	0.414	0.696
4	975	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	10.10	0.236	0.053	0.029	0.700	1.017
4	975	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	13.72	0.320	0.057	0.031	1.557	1.966
4	975	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	47.00	1.098	0.122	0.066	0.182	1.468
4	975	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.66	47.37	1.106	0.123	0.066	0.232	1.528
4	975	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	47.90	1.119	0.124	0.067	0.316	1.625
4	975	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	48.84	1.141	0.125	0.067	0.484	1.817
4	975	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	51.23	1.197	0.128	0.069	0.988	2.381

ECONOMIC RESULTS $ GRAPHICAL FORMAT

MODEL PLANT # 1



MODEL PLANT # 4



RESULTS FOR MODEL PLANTS 7 AND 8 (w Recycle for ESP-6)

DATE: 6/6/00

Comments:

1) Model Plant 7, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals

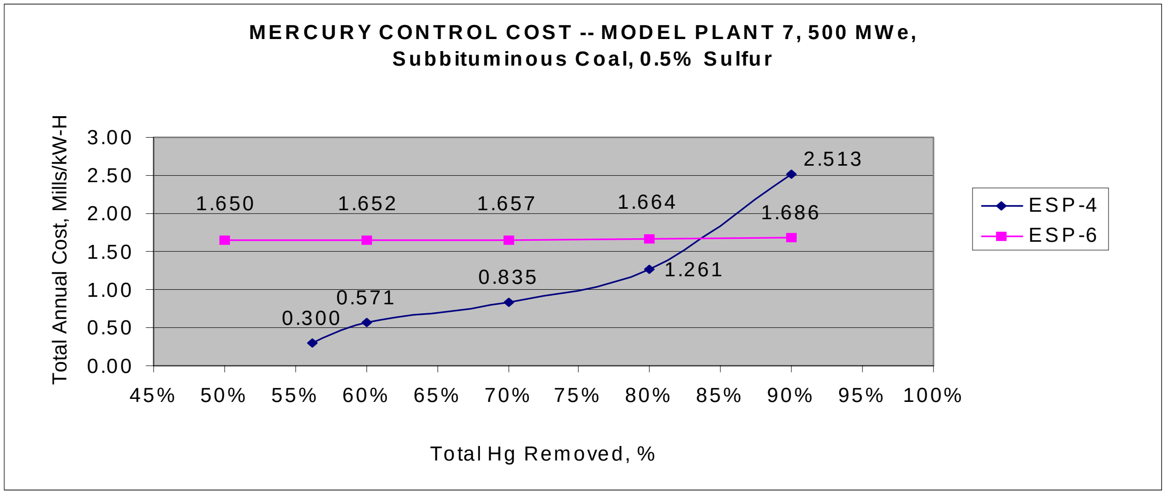
2) Model Plant 8, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

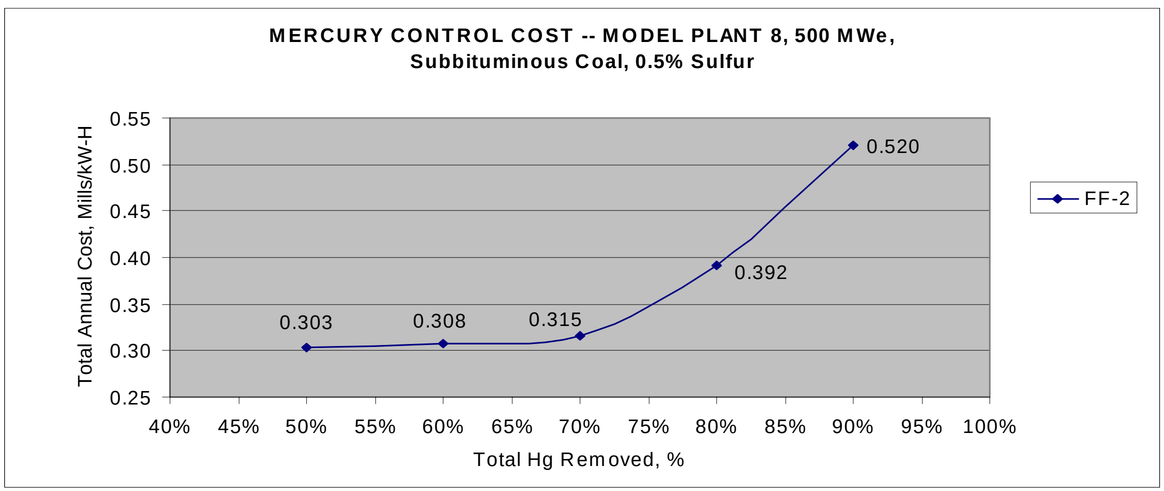
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
7	500	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	6.59	0.154	0.083	0.045	0.019	0.300
7	500	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	8.79	0.205	0.086	0.046	0.233	0.571
7	500	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	10.27	0.240	0.088	0.048	0.459	0.835
7	500	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	12.34	0.288	0.091	0.049	0.833	1.261
7	500	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	17.55	0.410	0.098	0.053	1.953	2.513
7	500	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	55.15	1.288	0.172	0.093	0.097	1.650
7	500	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	55.19	1.289	0.172	0.092	0.099	1.652
7	500	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	55.25	1.290	0.172	0.093	0.101	1.657
7	500	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	55.34	1.293	0.172	0.093	0.107	1.664
7	500	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	55.57	1.298	0.173	0.093	0.122	1.686
8	500	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	6.65	0.155	0.083	0.045	0.020	0.303
8	500	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	6.74	0.157	0.083	0.045	0.023	0.308
8	500	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	6.84	0.160	0.083	0.045	0.027	0.315
8	500	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	7.56	0.177	0.085	0.046	0.085	0.392
8	500	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	8.47	0.198	0.086	0.046	0.190	0.520

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT # 7



MODEL PLANT # 8



RESULTS FOR MODEL PLANTS 7 AND 8 **DATE: 06/06/2000**

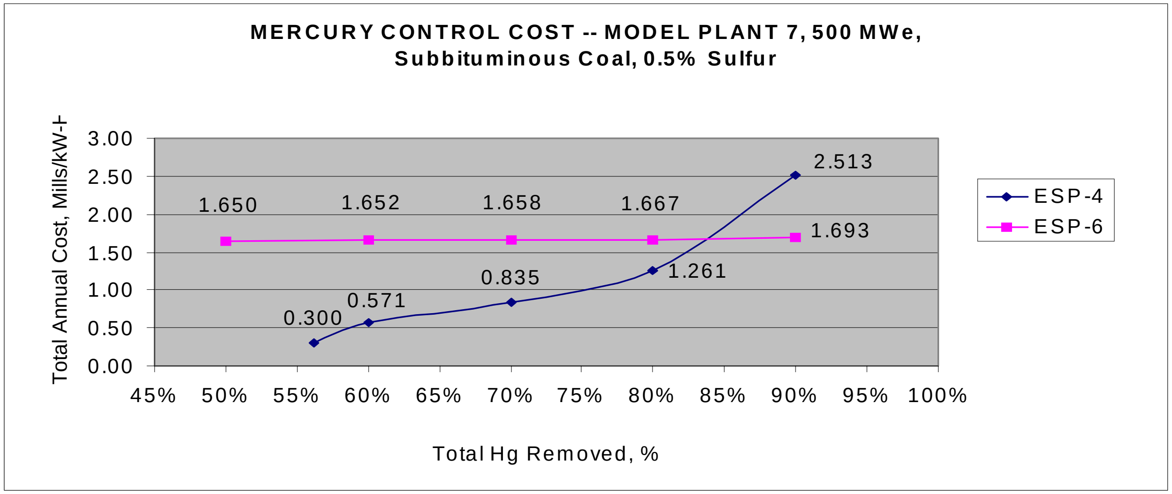
Comments:
1) Model Plant 7, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 8, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

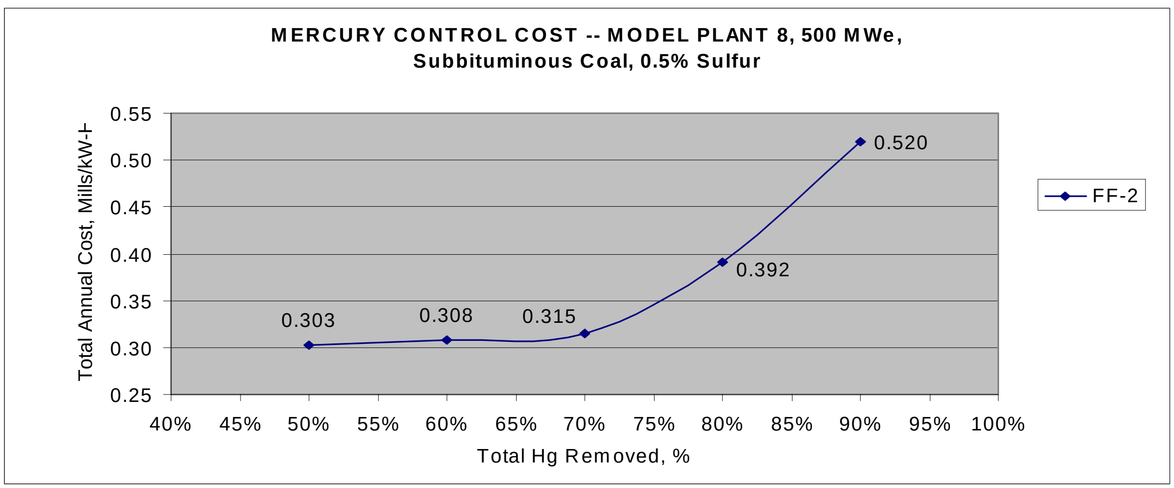
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
7	500	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	6.59	0.154	0.083	0.045	0.019	0.300
7	500	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	8.79	0.205	0.086	0.046	0.233	0.571
7	500	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	10.27	0.240	0.088	0.048	0.459	0.835
7	500	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	12.34	0.288	0.091	0.049	0.833	1.261
7	500	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	17.55	0.410	0.098	0.053	1.953	2.513
7	500	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	55.15	1.288	0.172	0.093	0.097	1.650
7	500	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	55.20	1.289	0.172	0.092	0.099	1.652
7	500	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	55.26	1.291	0.172	0.093	0.102	1.658
7	500	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	55.37	1.293	0.172	0.093	0.108	1.667
7	500	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	55.64	1.300	0.173	0.093	0.128	1.693
8	500	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	6.65	0.155	0.083	0.045	0.020	0.303
8	500	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	6.74	0.157	0.083	0.045	0.023	0.308
8	500	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	6.84	0.160	0.083	0.045	0.027	0.315
8	500	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	7.56	0.177	0.085	0.046	0.085	0.392
8	500	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	8.47	0.198	0.086	0.046	0.190	0.520

ECONOMIC RESULTS $ GRAPHICAL FORMAT

MODEL PLANT # 7



MODEL PLANT # 8



RESULTS FOR MODEL PLANTS 7 AND 8 (ADP+40) **DATE: 6/6/00**

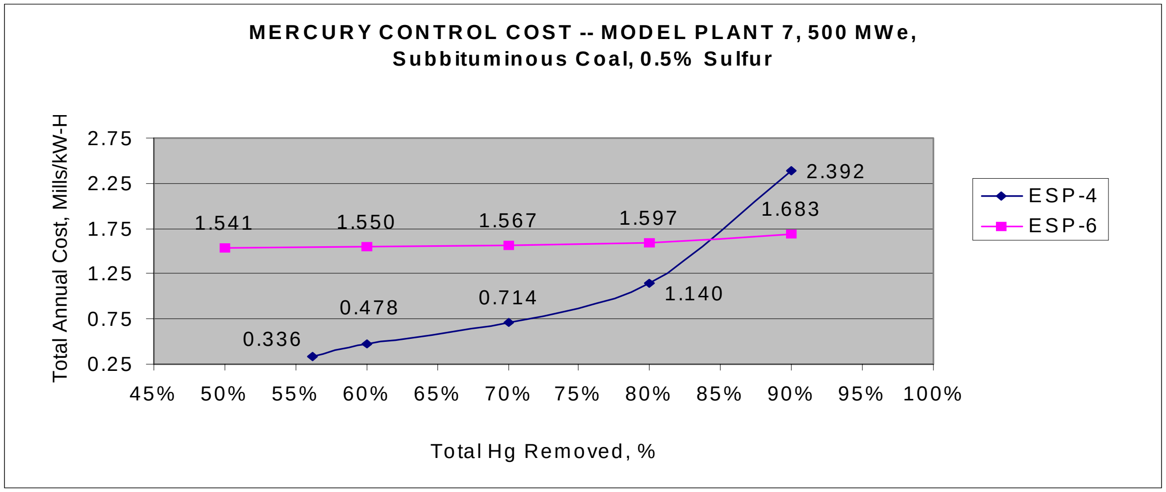
Comments:
1) Model Plant 7, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 8, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

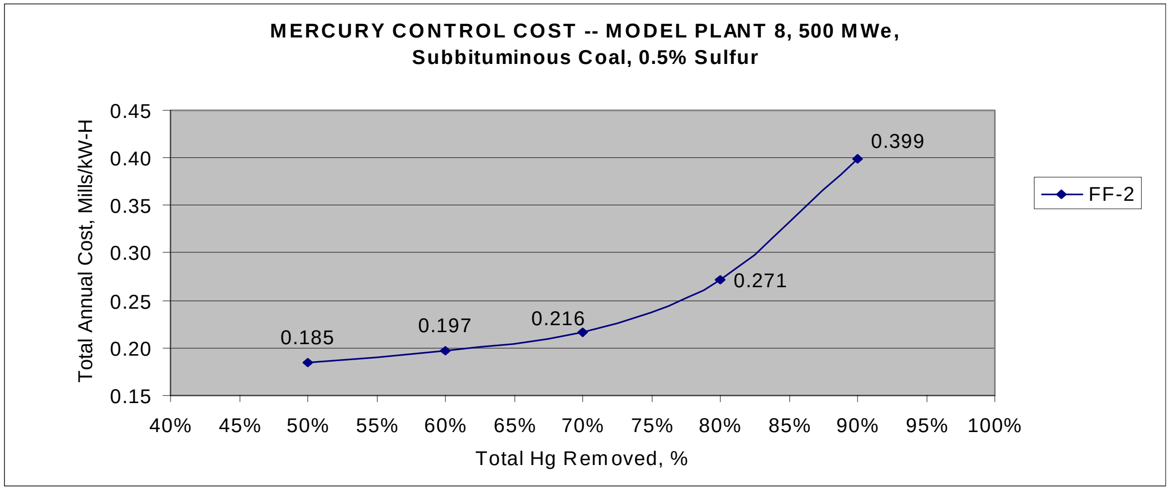
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
7	500	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	0.00	3.92	0.092	0.078	0.042	0.125	0.336
7	500	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	2.36	4.83	0.113	0.079	0.043	0.243	0.478
7	500	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	4.87	6.15	0.144	0.081	0.044	0.446	0.714
7	500	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	9.00	8.22	0.192	0.084	0.045	0.820	1.140
7	500	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.39	13.42	0.313	0.090	0.049	1.939	2.392
7	500	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.04	51.17	1.195	0.165	0.089	0.093	1.541
7	500	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.06	51.28	1.198	0.164	0.089	0.100	1.550
7	500	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.09	51.44	1.201	0.165	0.089	0.111	1.567
7	500	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.17	51.70	1.208	0.166	0.089	0.134	1.597
7	500	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.38	52.36	1.223	0.167	0.090	0.204	1.683
8	500	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.01	2.57	0.060	0.076	0.041	0.009	0.185
8	500	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.04	2.75	0.064	0.076	0.041	0.017	0.197
8	500	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.09	2.95	0.069	0.076	0.041	0.030	0.216
8	500	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.73	3.44	0.080	0.077	0.041	0.072	0.271
8	500	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	1.89	4.35	0.102	0.078	0.042	0.177	0.399

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT # 7



MODEL PLANT # 8



RESULTS FOR MODEL PLANTS 7 AND 8 **DATE: 05/22/2000**

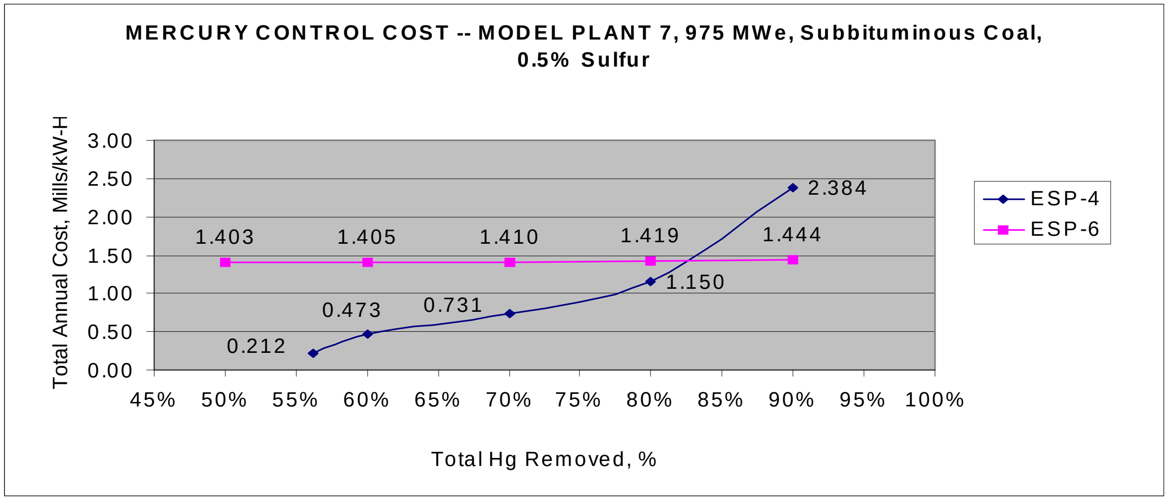
Comments:
1) Model Plant 7, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 8, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

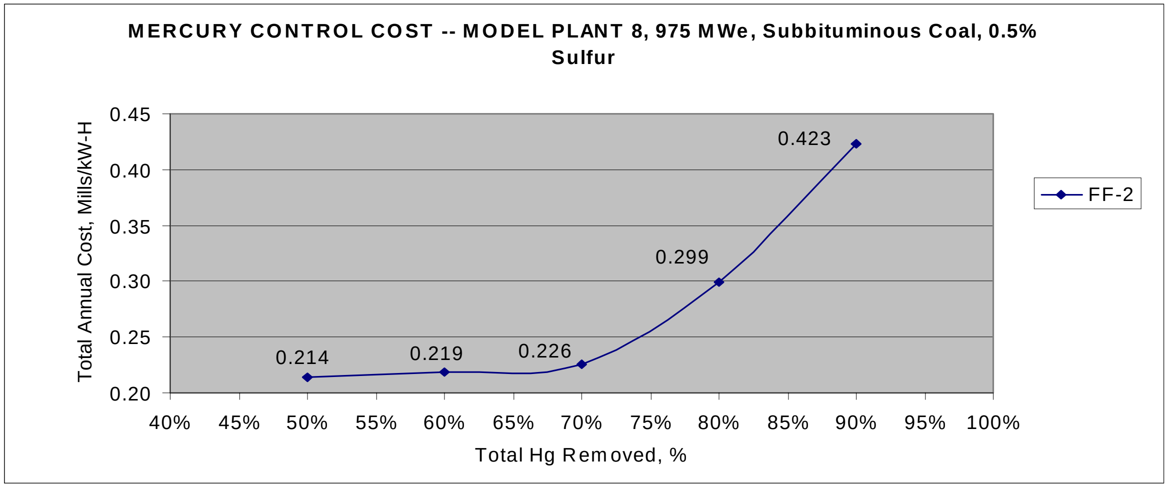
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
7	975	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	5.25	0.123	0.046	0.025	0.019	0.212
7	975	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	7.07	0.165	0.049	0.026	0.233	0.473
7	975	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	8.32	0.194	0.050	0.027	0.459	0.731
7	975	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	10.09	0.236	0.053	0.028	0.833	1.150
7	975	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	14.61	0.341	0.058	0.031	1.953	2.384
7	975	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	47.74	1.115	0.124	0.067	0.097	1.403
7	975	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	47.78	1.116	0.124	0.067	0.099	1.405
7	975	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	47.83	1.117	0.124	0.067	0.102	1.410
7	975	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	47.92	1.119	0.124	0.067	0.109	1.419
7	975	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	48.14	1.124	0.125	0.067	0.128	1.444
8	975	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	5.30	0.124	0.046	0.025	0.020	0.214
8	975	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	5.37	0.125	0.046	0.025	0.023	0.219
8	975	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	5.45	0.127	0.046	0.025	0.027	0.226
8	975	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	6.04	0.141	0.047	0.025	0.085	0.299
8	975	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	6.80	0.159	0.048	0.026	0.190	0.423

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 7



MODEL PLANT # 8



RESULTS FOR MODEL PLANTS 10 AND 13 **DATE: 5/22/00**

Comments:

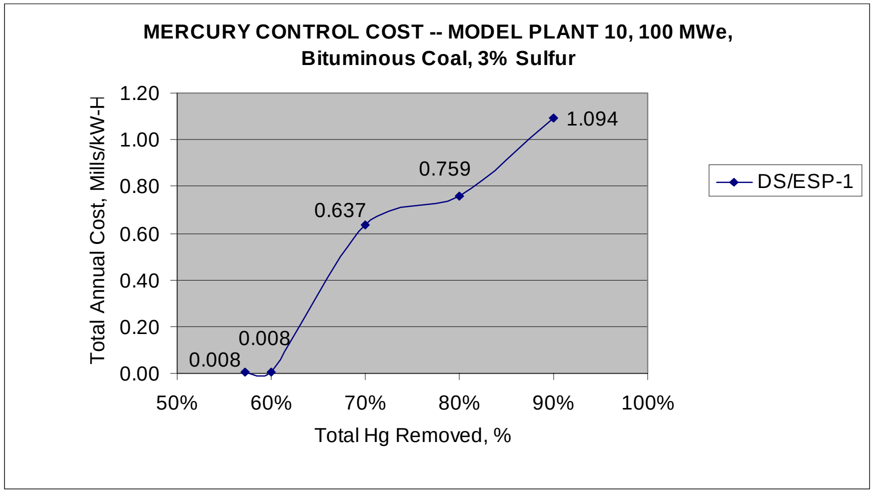
1) Model Plant 10, DS/ESP-1: Minimum Hg removal = 57.2% for DS/ESP Combination with Eastern Bituminous Coals
2) Model Plant 10: Capital Cost Only Includes Sorbent Injection Equipment (accounts for storage/transfer of sorbent)
3) Model Plant 13, ESP-4: Minimum Hg removal = 58.8% for ESP with Eastern Bituminous Coals
4) Model Plant 13, ESP-6: Minimum Hg removal = 61.3% for ESP with Eastern Bituminous Coals

See plot of results below table

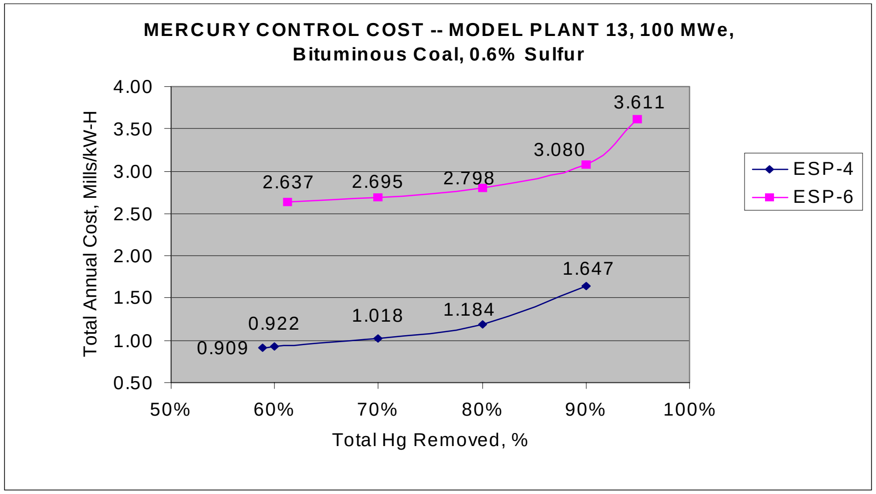
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	57.20%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	0.00	0.18	0.004	0.000	0.000	0.003	0.008
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	0.00	0.18	0.004	0.000	0.000	0.003	0.008
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	0.42	1.58	0.037	0.363	0.195	0.042	0.637
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.34	2.95	0.069	0.365	0.197	0.128	0.759
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	4.12	5.84	0.136	0.370	0.199	0.388	1.094
13	100	58.80%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	13.11	0.306	0.378	0.203	0.022	0.909
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.06	13.39	0.313	0.378	0.204	0.027	0.922
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.79	14.72	0.344	0.381	0.205	0.088	1.018
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.24	16.40	0.383	0.383	0.206	0.211	1.184
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	6.61	20.05	0.468	0.389	0.210	0.580	1.647
13	100	61.30%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	76.37	1.784	0.495	0.266	0.092	2.637
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.38	77.36	1.807	0.497	0.267	0.124	2.695
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.23	78.56	1.835	0.499	0.268	0.196	2.798
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	3.78	81.10	1.894	0.503	0.271	0.412	3.080
13	100	95.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	8.89	84.94	1.984	0.509	0.274	0.844	3.611

ECONOMIC RESULTS Ş GRAPHICAL FORMAT

MODEL PLANT # 10



MODEL PLANT # 13



RESULTS FOR MODEL PLANTS 10 AND 13 (ADP+40) **DATE: 6/6/00**

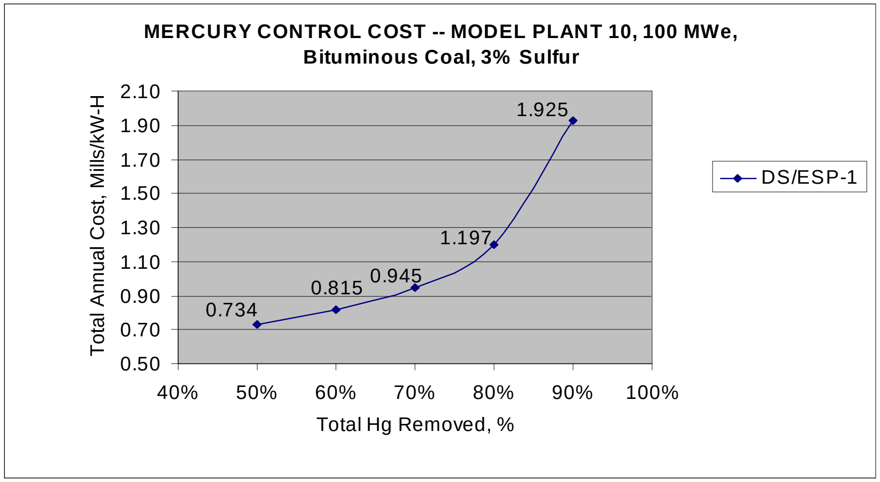
Comments:

See plot of results below table

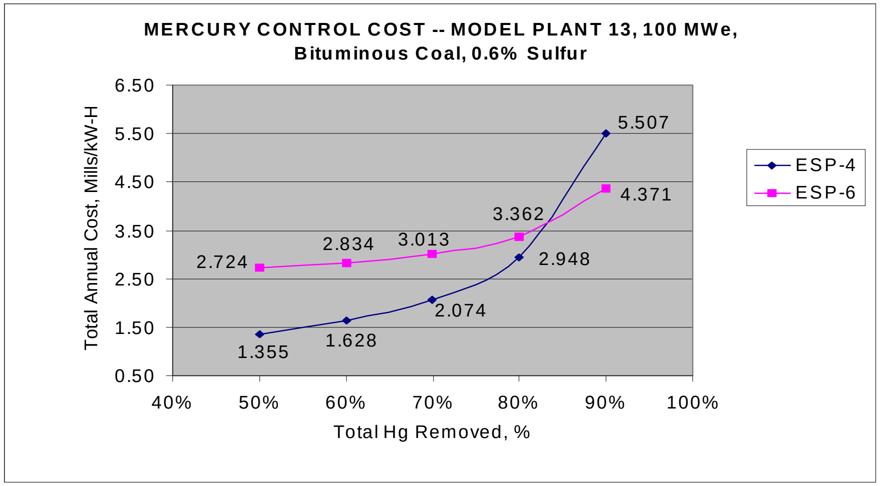
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.15	2.69	0.063	0.365	0.196	0.110	0.734
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.79	3.49	0.081	0.366	0.197	0.170	0.815
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	2.86	4.64	0.108	0.368	0.198	0.270	0.945
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	5.01	6.62	0.155	0.371	0.200	0.471	1.197
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	11.44	11.49	0.268	0.379	0.204	1.073	1.925
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	5.31	13.49	0.315	0.377	0.203	0.459	1.355
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	7.96	15.43	0.360	0.380	0.205	0.683	1.628
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	12.37	18.31	0.428	0.385	0.207	1.055	2.074
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.19	23.36	0.546	0.392	0.211	1.800	2.948
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	47.64	36.04	0.842	0.410	0.221	4.035	5.507
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	1.98	73.77	1.723	0.490	0.264	0.248	2.724
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	2.98	74.76	1.746	0.491	0.264	0.333	2.834
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	4.65	76.20	1.780	0.493	0.266	0.474	3.013
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	8.00	78.71	1.839	0.497	0.268	0.758	3.362
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	18.05	84.91	1.983	0.506	0.273	1.609	4.371

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 10



MODEL PLANT # 13



Sensitivity Results: Plants 4, ESP-4, W & WO Ductwork for Added Residence Time **DATE: 6/14/00**

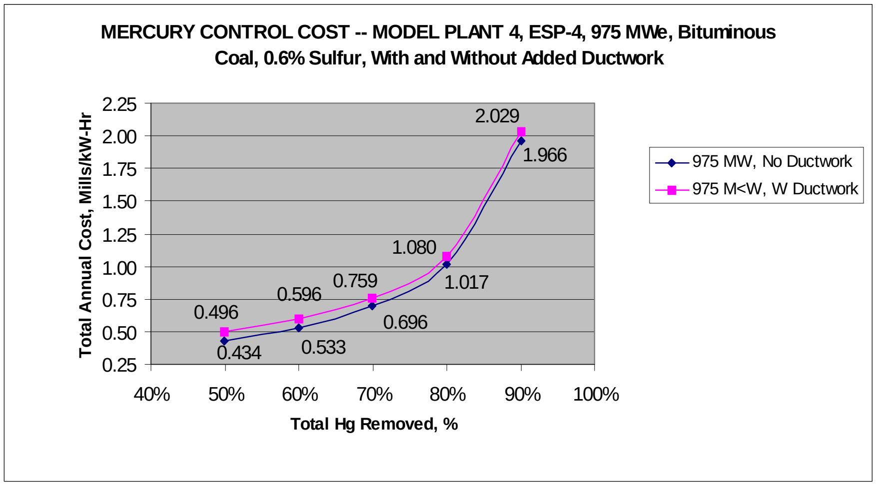
Comments:
Application: Plant 4, ESP-4, Ductwork added upstream of ESP
Results presented with and without added ductwork
Plant sizes: 975, 500 and 100 MWe
Type of ductwork: carbon steel, polymer-lined, insulated (reflects a conservative selection of material)
Cost of ductwork: $134/sq ft
Installation labor: 0.8 hrs/sq ft
Number of ducts: 2
Duct gas velocity: 2800 ft/min
Retrofit factor: 1.3
Gas residence time in new duct: 1 second

See plot of results below table

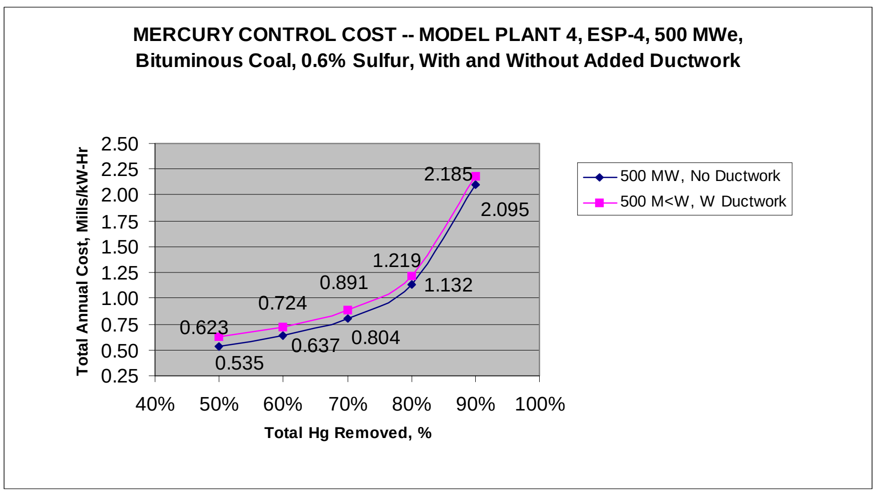
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
4	975	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	7.37	0.17	0.049	0.027	0.185	0.434
4	975	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	7.90	0.18	0.050	0.027	0.271	0.533
4	975	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	8.70	0.20	0.051	0.028	0.414	0.696
4	975	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	SCR	FG Cooling, ADP+18F	8.03	10.10	0.24	0.053	0.029	0.700	1.017
4	975	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	13.72	0.32	0.057	0.031	1.557	1.966
4	975	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	1.94	10.04	0.23	0.050	0.027	0.185	0.496
4	975	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	2.95	10.57	0.25	0.050	0.027	0.271	0.596
4	975	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	4.64	11.37	0.27	0.051	0.028	0.414	0.759
4	975	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	8.03	12.77	0.30	0.053	0.029	0.700	1.080
4	975	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	18.17	16.39	0.38	0.058	0.031	1.557	2.029
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	9.23	0.22	0.087	0.047	0.185	0.535
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	9.86	0.23	0.088	0.047	0.271	0.637
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	10.79	0.25	0.090	0.048	0.414	0.804
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	12.44	0.29	0.092	0.049	0.700	1.132
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	16.62	0.39	0.097	0.052	1.557	2.095
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	1.94	12.95	0.30	0.088	0.047	0.185	0.623
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	2.95	13.58	0.32	0.088	0.048	0.271	0.724
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	4.64	14.52	0.34	0.090	0.048	0.414	0.891
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	8.03	16.17	0.38	0.092	0.050	0.700	1.219
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	18.17	20.43	0.48	0.098	0.053	1.557	2.185
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	16.08	0.38	0.383	0.206	0.185	1.150
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	17.08	0.40	0.385	0.207	0.271	1.262
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	18.54	0.43	0.387	0.208	0.414	1.442
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	SCR	FG Cooling, ADP+18F	8.03	21.06	0.49	0.391	0.210	0.700	1.793
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	27.30	0.64	0.400	0.215	1.557	2.810
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	1.94	21.98	0.51	0.383	0.206	0.185	1.288
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	2.95	22.97	0.54	0.385	0.207	0.271	1.400
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	4.64	24.43	0.57	0.387	0.209	0.414	1.580
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	8.03	26.96	0.63	0.391	0.211	0.700	1.931
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	18.17	33.19	0.78	0.400	0.216	1.557	2.948

ECONOMIC RESULTS S GRAPHICAL FORMAT

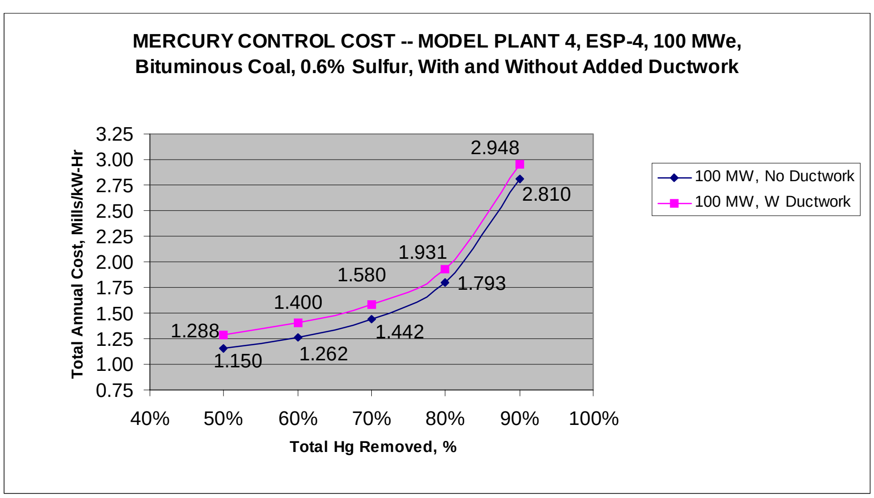
MODEL PLANT # 4, 975 MW



MODEL PLANT #4, 500 MW



MODEL PLANT #4, 100 MW



RESULTS FOR MODEL PLANTS 10 AND 13 (Recycle for ESP-6) **DATE: 6/6/00**

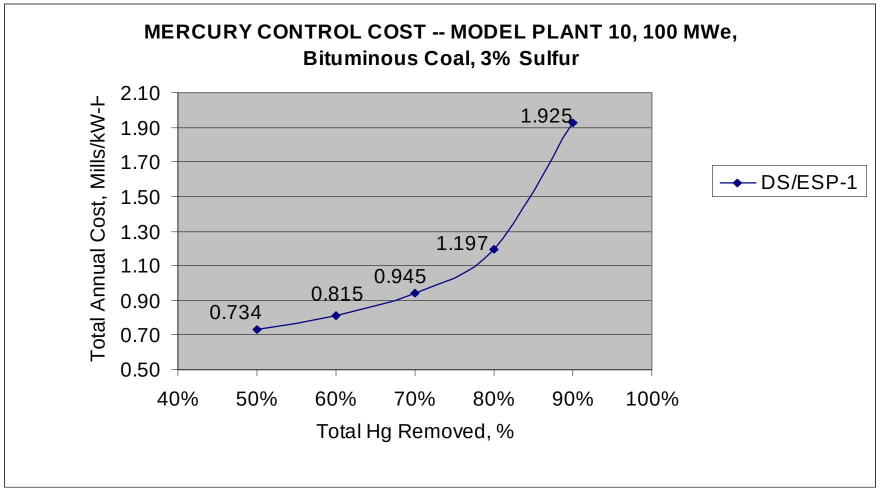
Comments:

See plot of results below table

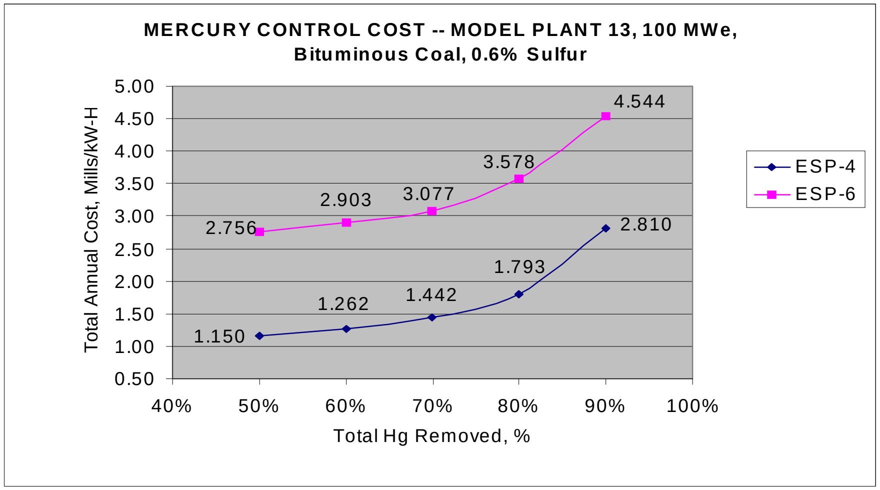
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.15	2.69	0.063	0.365	0.196	0.110	0.734
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.79	3.49	0.081	0.366	0.197	0.170	0.815
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	2.86	4.64	0.108	0.368	0.198	0.270	0.945
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	5.01	6.62	0.155	0.371	0.200	0.471	1.197
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	11.44	11.49	0.268	0.379	0.204	1.073	1.925
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	16.08	0.376	0.383	0.206	0.185	1.150
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	17.08	0.399	0.385	0.207	0.271	1.262
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	18.54	0.433	0.387	0.208	0.414	1.442
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	21.06	0.492	0.391	0.210	0.700	1.793
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	27.30	0.638	0.400	0.215	1.557	2.810
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	78.11	1.824	0.498	0.268	0.166	2.756
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	79.59	1.859	0.500	0.269	0.274	2.903
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	81.10	1.894	0.503	0.271	0.409	3.077
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	84.78	1.980	0.508	0.274	0.816	3.578
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	22.47	90.73	2.119	0.517	0.279	1.629	4.544

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 10



MODEL PLANT # 13



RESULTS FOR MODEL PLANTS 10 AND 13 **DATE: 5/22/00**

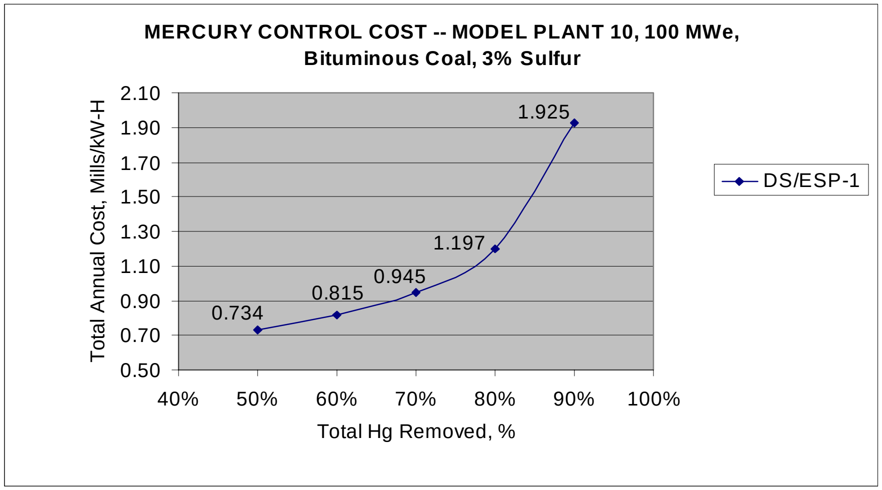
Comments:

See plot of results below table

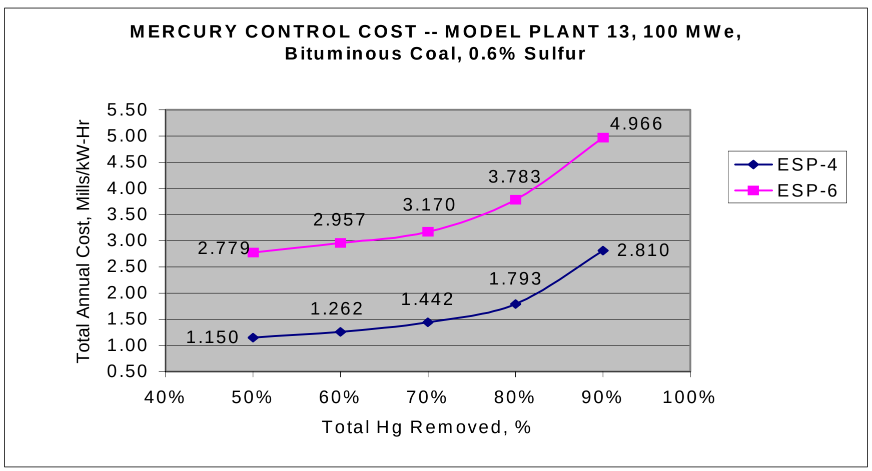
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.15	2.69	0.063	0.365	0.196	0.110	0.734
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.79	3.49	0.081	0.366	0.197	0.170	0.815
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	2.86	4.64	0.108	0.368	0.198	0.270	0.945
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	5.01	6.62	0.155	0.371	0.200	0.471	1.197
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	11.44	11.49	0.268	0.379	0.204	1.073	1.925
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	16.08	0.376	0.383	0.206	0.185	1.150
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	17.08	0.399	0.385	0.207	0.271	1.262
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	18.54	0.433	0.387	0.208	0.414	1.442
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	21.06	0.492	0.391	0.210	0.700	1.793
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	27.30	0.638	0.400	0.215	1.557	2.810
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	78.36	1.830	0.498	0.268	0.182	2.779
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	80.07	1.870	0.501	0.270	0.316	2.957
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	81.81	1.911	0.504	0.271	0.484	3.170
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	86.06	2.010	0.510	0.275	0.987	3.783
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	22.47	92.95	2.171	0.520	0.280	1.994	4.966

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 10



MODEL PLANT # 13



RESULTS FOR MODEL PLANTS 16 AND 17 **05/22/2000**

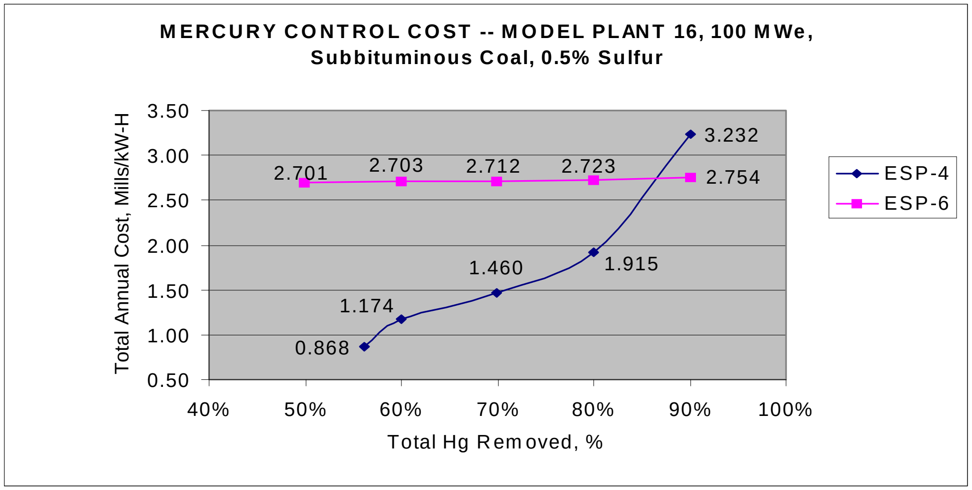
Comments:
1) Model Plant 16, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 17, FF-2: Minimum Hg removal = 75.7% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

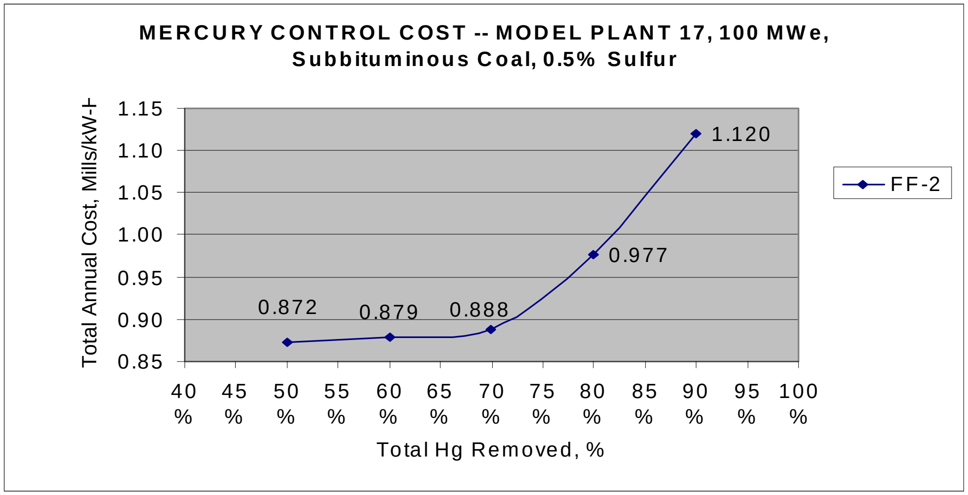
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
16	100	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	11.63	0.272	0.375	0.202	0.019	0.868
16	100	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	15.21	0.355	0.381	0.205	0.232	1.174
16	100	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	17.52	0.409	0.385	0.207	0.459	1.460
16	100	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	20.68	0.483	0.390	0.210	0.832	1.915
16	100	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	28.38	0.663	0.401	0.216	1.953	3.232
16	100	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	78.65	1.837	0.499	0.269	0.097	2.701
16	100	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	78.73	1.839	0.498	0.268	0.099	2.703
16	100	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	78.84	1.841	0.499	0.269	0.102	2.712
16	100	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	79.02	1.846	0.500	0.269	0.108	2.723
16	100	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	79.46	1.856	0.500	0.269	0.128	2.754
17	100	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	11.73	0.274	0.376	0.203	0.019	0.872
17	100	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	11.88	0.278	0.376	0.203	0.022	0.879
17	100	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	12.05	0.282	0.377	0.203	0.027	0.888
17	100	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	13.25	0.310	0.379	0.204	0.085	0.977
17	100	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	14.71	0.344	0.381	0.205	0.189	1.120

ECONOMIC RESULTS Ş GRAPHICAL FORMAT

MODEL PLANT # 16



MODEL PLANT # 17



RESULTS FOR MODEL PLANTS 16 AND 17 (Recycle for ESP-6) **DATE: 6/6/00**

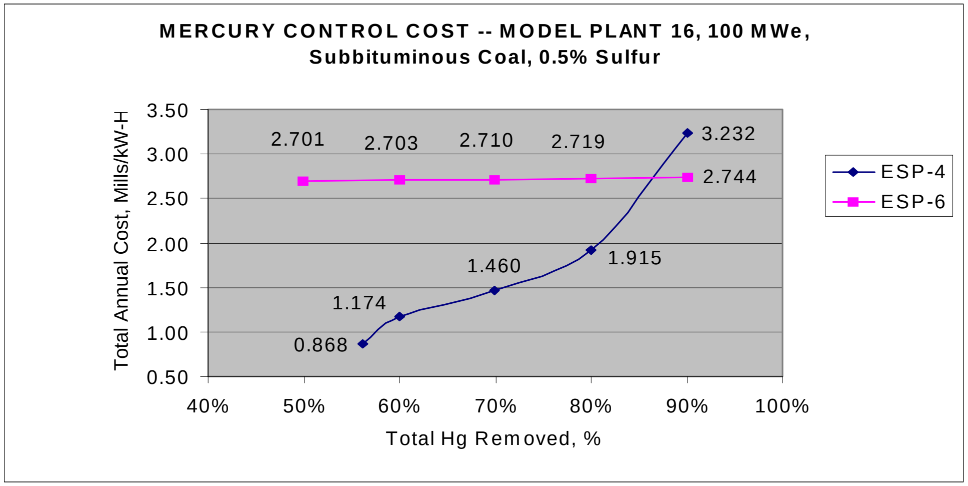
Comments:
1) Model Plant 16, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 17, FF-2: Minimum Hg removal = 75.7% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

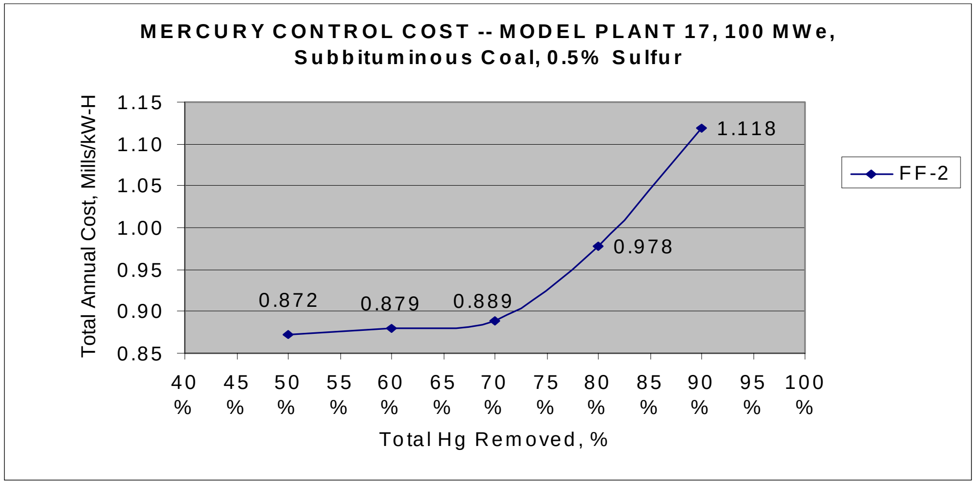
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
16	100	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	11.63	0.272	0.375	0.202	0.019	0.868
16	100	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	15.21	0.355	0.381	0.205	0.232	1.174
16	100	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	17.52	0.409	0.385	0.207	0.459	1.460
16	100	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	20.68	0.483	0.390	0.210	0.832	1.915
16	100	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	28.38	0.663	0.401	0.216	1.953	3.232
16	100	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	78.64	1.837	0.499	0.269	0.097	2.701
16	100	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	78.70	1.838	0.498	0.268	0.099	2.703
16	100	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	78.80	1.841	0.499	0.269	0.101	2.710
16	100	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	78.96	1.844	0.500	0.269	0.106	2.719
16	100	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	79.30	1.852	0.500	0.269	0.122	2.744
17	100	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	11.73	0.274	0.376	0.203	0.019	0.872
17	100	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	11.88	0.278	0.376	0.203	0.022	0.879
17	100	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	12.07	0.282	0.377	0.203	0.027	0.889
17	100	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	13.28	0.310	0.379	0.204	0.085	0.978
17	100	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	14.67	0.343	0.381	0.205	0.189	1.118

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 16



MODEL PLANT # 17



RESULTS FOR MODEL PLANTS 16 AND 17 (ADP+40) **05/22/2000**

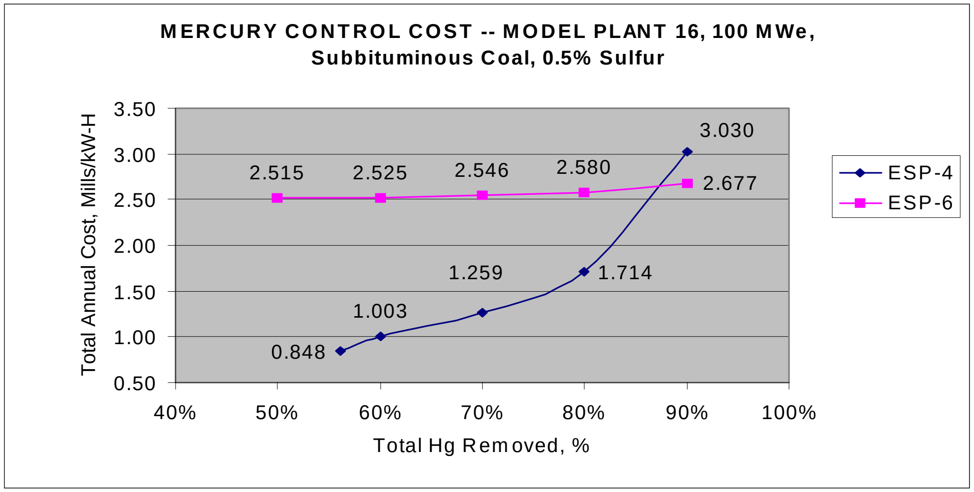
Comments:
1) Model Plant 16, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 17, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

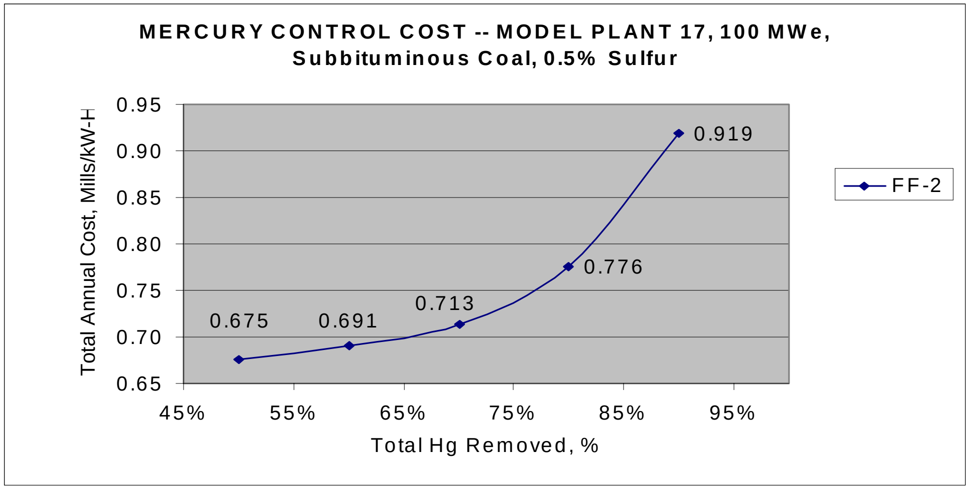
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
16	100	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	1.32	6.84	0.160	0.366	0.197	0.125	0.848
16	100	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	2.62	8.28	0.194	0.368	0.198	0.243	1.003
16	100	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	4.87	10.33	0.241	0.372	0.200	0.446	1.259
16	100	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	9.00	13.49	0.315	0.376	0.203	0.820	1.714
16	100	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.39	21.18	0.495	0.388	0.209	1.939	3.030
16	100	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.13	71.70	1.675	0.486	0.262	0.093	2.515
16	100	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.21	71.89	1.679	0.485	0.261	0.100	2.525
16	100	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.34	72.15	1.685	0.487	0.262	0.111	2.546
16	100	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.59	72.59	1.696	0.488	0.263	0.134	2.580
16	100	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	1.36	73.65	1.720	0.489	0.264	0.204	2.677
17	100	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.03	4.63	0.108	0.363	0.195	0.009	0.675
17	100	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.11	4.92	0.115	0.364	0.196	0.016	0.691
17	100	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.26	5.26	0.123	0.364	0.196	0.030	0.713
17	100	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.73	6.06	0.142	0.366	0.197	0.072	0.776
17	100	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	1.89	7.52	0.176	0.368	0.198	0.177	0.919

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 16



MODEL PLANT # 17



Sensitivity Results: Plant 4, ESP-6 & ESP-7, No ICR Mod, Combined Lime-Carbon Sorbent **DATE: 6/14/00**
500 MW

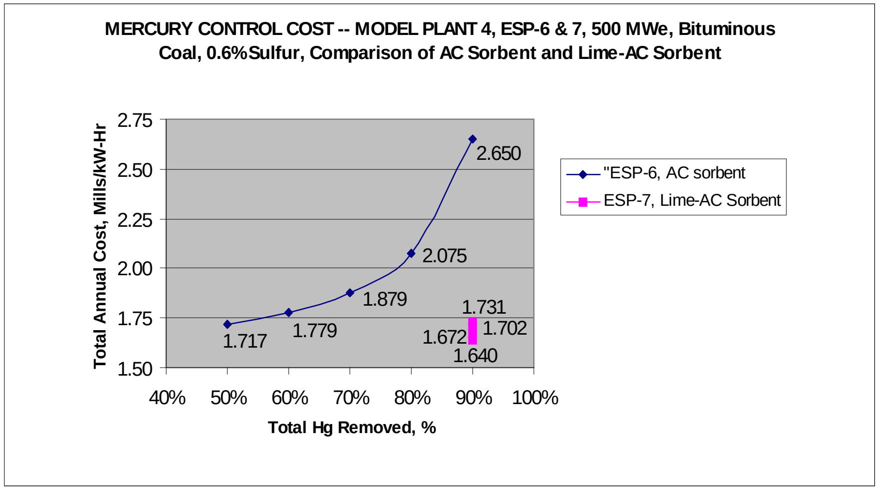
Comments:
Application: Plant 4, ESP-6, AC sorbent (50-90% Removal); Plant 4, ESP-7, AC-Lime Sorbent (90%+ removal)
Plant size: 500 MWe
AC sorbent Cost = $908/Ton
AC-Lime Sorbent Cost = $149/Ton, Assumes C:Lime ratio = 2:19
ESP-7 Sensitivity Cases Assume 90%+ Hg Removal based on ADA Technologies tests at PSE&G
ESP-7 Sensitivity Cases run for 1, 2, 3, 4 lb/Mmacf Sorbent Concentration
ESP-6 Comparison Cases Run for 50, 60, 70, 80, 90% Hg Removal

See plot of results below table

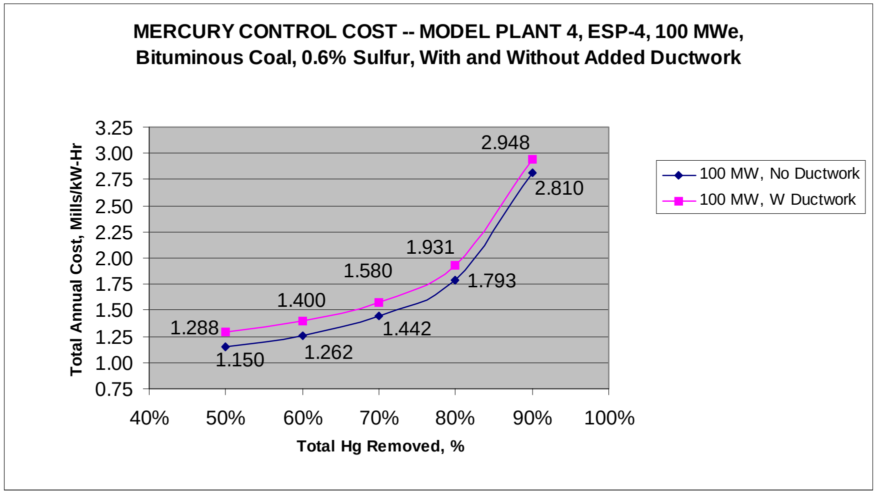
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
4	500	50.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	54.48	1.27	0.171	0.092	0.182	1.717
4	500	60.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	1.66	54.91	1.28	0.171	0.092	0.232	1.779
4	500	70.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	55.55	1.30	0.172	0.093	0.316	1.879
4	500	80.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	56.67	1.32	0.174	0.094	0.484	2.075
4	500	90.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	59.46	1.39	0.178	0.096	0.988	2.650
4	500	90.00%	Bit	0.6	ESP	ESP-7	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.00	54.33	1.27	0.171	0.092	0.108	1.640
4	500	90.00%	Bit	0.6	ESP	ESP-7	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.00	54.94	1.28	0.172	0.092	0.125	1.672
4	500	90.00%	Bit	0.6	ESP	ESP-7	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	3.00	55.46	1.30	0.173	0.093	0.141	1.702
4	500	90.00%	Bit	0.6	ESP	ESP-7	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.00	55.93	1.31	0.173	0.093	0.158	1.731

ECONOMIC RESULTS \$ GRAPHICAL FORMAT

MODEL PLANT # 4, 500 MW, Comparison of ESP-6 and ESP-7



MODEL PLANT # 4, 100 MW



TECHNICAL REPORT DATA

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16. ABSTRACT The report presents estimates of the performance and cost of powdered activated carbon (PAC) injection-based mercury control technologies and projections of costs for future applications. (NOTE: Under the Clean Air Act Amendments of 1990, the U.S. EPA has to determine whether mercury emissions from coal-fired power plants should be regulated. These estimates and projections were developed to aid in this determination.) Estimates based on currently available data using PAC range from 0.305 to 3.783 mills/kWh. However, the higher costs are associated with the minority of plants using hot-side electrostatic precipitators (HESPs). If these costs are excluded, the estimates range from 0.305 to 1.915 mills/kWh. Cost projections, developed based on using a composite lime-PAC sorbent for mercury re-moval, range from 0.183 to 2.270 mills/kWh, with the higher costs being associated with the minority of plants using HESPs. A comparison of mercury control costs with those of nitrogen oxides (NOx) controls reveals that total annual costs for mer-cury lie mostly between applicable costs for low Nox burners and selective catalytic reduction. The performance and cost estimates of the PAC injection-based mercury control technologies presented in the report are based on a relatively few data points from pilot-scale tests and, therefore, are considered to be preliminary.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Combustion	Pollution Control	13B	21B
Mercury (Metal)	Activated Carbon	Stationary Sources	07B	11G
Emission	Performance		14G	
Electric Utilities	Cost Estimates		13B	05A, 14A
Boilers	Electrostatic Pre-cipitators (ESPs)		21D	13K
Coal				

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