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MEMORANDUM

TO: Mary Jo Krolewski, Gene Hua Sun, EPA

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CC: Barry Galef, Walter Gawlak, ICF

Subject: Mercury Control Cost Calculations: Assumptions, Approach, and Results
EPA Contract No.68-D7-0081, Task 011, Subtask 02.

Under Section 112 of the Clean Air Act Amendments (CAAA) of 1990, the Environmental Protection Agency (EPA) is required to determine whether mercury emissions from coal-fired power plants should be regulated. In 1999, EPA presented preliminary estimates of the performance and the costs of promising mercury control technologies applicable to coal-fired electric utility boilers that were used in EPA's analyses using ICF's Integrated Planning Model (IPM™).[1] Since that 1999 EPA report, EPA and the Department of Energy (DOE) have developed additional estimates of costs and performance of mercury control technologies based on test results obtained from pilot-scale systems. These pilot-scale results were then incorporated by DOE's National Energy Technology Laboratory (NETL) into their Mercury Control Performance and Cost Model (MCPCM).[2] Subsequent to that development of the MCPCM, EPA and DOE developed a methodology for applying the MCPCM cost algorithms to the boiler population in EPA's data set supporting the IPM™ modeling of EPA's hypothetical mercury Maximum Achievable Control Technology (MACT) regulatory scenario (which also includes Title IV constraints for SO_2 and NO_x,and the SIP Call policy constraint for NO_x in the 22 Eastern States and the District of Columbia), HgMACT1d (EPA, 1999a).[3]

The purpose of this memorandum is to explain how the MCPCM cost algorithms were used in conjunction with the boiler population and the modeling results of the IPM™ run, HgMACT1d, to calculate the costs of controlling mercury emissions from coal-fired electric generating units in the U.S. in 2010 for

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[1] *Analysis of Emissions Reduction Options for the Electric Power Industry*, Office of Air and Radiation, U.S. Environmental Protection Agency, March 1999 (EPA, 1999a).

[2] Srivastava, Ravi K., Charles B. Sedman, and James D. Kilgroe, *Performance and Cost of Mercury Emission Control Technology Applications on Electric Utility Boilers*, Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, September, 2000 (EPA, 2000).

[3] Mercury control technology assumptions determined during EPA's meeting with DOE at EPA, Washington, DC, August 22-23, 2000 (EPA-DOE, 2000). See Excel file, "Hg control and cost assumptions for IPM, 8-30-00.xls," provided by DOE on August 30, 2000 (DOE, 2000).

EPA's hypothetical mercury MACT regulatory scenario (EPA, 1999a). This memorandum describes the assumptions and approach developed by ICF, and reviewed by EPA, to calculate mercury control costs and presents a summary of the mercury control costs calculated through a spreadsheet-based analysis. In this analysis, the mercury control *technology* costs were calculated using (i) EPA-DOE assumptions about applicability of mercury control technology (EPA-DOE, 2000; DOE, 2000), (ii) DOE's mercury control technology cost and performance characteristics (DOE, 2000), and (iii) the generation, generating capacity, and pollution control technology installation forecasts for, and the type and the sulfur grade of coal projected to be consumed in, 2010, based on the results of the EPA's mercury MACT IPM™ run, HgMACT1d (EPA, 1999b).[4]

The mercury control costs were developed for two hypothetical mercury MACT scenarios: (i) 60 percent or greater reduction, and (ii) 80 percent or greater reduction. In each of these scenarios (which are similar to the HgMACT1d regulatory scenario), reduction requirements for other pollutants (i.e., SO_2 and NO_x) would result in some amounts of mercury reductions over the 60 percent and the 80 percent levels (achieved through installation of appropriate mercury control technology), with little or no cost directly attributable to mercury control (EPA, 2000; DOE, 2000). Thus, mercury reductions range (i) from 60 to 95 percent under the 60 percent or greater reduction scenario and (ii) from 80 to 95 percent under the 80 percent or greater reduction scenario.[5]

Specifically, for about 9.5 percent of coal-fired capacity, prior modeling results of HgMACT1d suggest that both scrubbers and selective catalytic reduction (SCR) controls (to control SO_2 and NO_x respectively) would be installed, and that, in combination, these two types of controls would reduce mercury emissions from these plants by 95 percent.[6] For about 13.5 percent of coal-fired capacity, prior modeling results suggest that power plants would install scrubbers (without SCR) to meet non-mercury air pollution requirements, and that these controls would reduce mercury emissions from these plants by 70 percent. For the remaining 77 percent of coal-fired capacity, prior modeling results of HgMACT1d do not suggest any additional, non-mercury-specific controls that would simultaneously reduce mercury emissions. Thus, for the purposes of calculating mercury control costs, it was assumed that power plants would be required to add control equipment specifically for mercury reduction for the same portion (i.e., 77 percent) of coal-fired capacity both under the 60 percent or greater and under the 80 percent or greater reduction scenarios. While the percent reductions described in this paragraph are based on the year 2010-results (i.e., pollution control technology retrofit decisions) of the HgMACT1d scenario, the associated generating capacities reported in this paragraph are based on the year 2000-generating capacities of the entire population of coal steam generating units with capacities greater than 25 MW in the EPA's boiler population data set used for modeling HgMACT1d scenario.

For each of the two mercury reduction scenarios, separate cost estimates were developed based on use of powdered activated carbon (PAC) only and use of a composite sorbent (lime and PAC). The results

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4 Results of EPA's IPM™ run, HgMACT1d. **http://www.epa.gov/acidrain/capi**/ (EPA, 1999b).

5 The percent of mercury reduction corresponds to the *combined* mercury removal efficiency of both (i) the existing (non-mercury) pollution control technology, and (ii) the appropriate mercury control technology (if additionally required under a mercury MACT scenario), installed by 2010.

6 The SCRs would normally be operated only during the five-month ozone season, May through September, to comply with the summer NO_x reduction requirement under the NO_x SIP Call policy; however, because capital costs for the SCRs were already incurred, for the purposes of mercury control cost calculations, it was assumed that the SCRs would be operated all through the year to maximize mercury reduction. Hence, the additional seven months of incremental variable O&M costs for SCRs were attributed to mercury control rather than to NO_x control in this analysis.

indicate that mercury control costs increase as the required amount of mercury reduction increases, and decrease if composite sorbent rather than only PAC is used. Specifically, the mercury control costs are (i) approximately $1.7 billion for achieving mercury reductions that range from 60 to 95 percent under the 60 percent or greater reduction scenario, and (ii) approximately $2.7 billion for achieving reductions that range from 80 to 95 percent under the 80 percent or greater reduction scenario, using PAC as the only sorbent.[7] EPA estimated that these costs would decrease by over 40 percent to approximately $1.1 billion and $1.7 billion, respectively, if composite sorbent was used (EPA, 2000). These composite sorbent mercury control costs are approximately 50 percent and 25 percent *lower* for the 60 percent or greater and for the 80 percent or greater reduction scenarios, respectively, than EPA's original mercury control cost estimate of approximately $2.3 billion (EPA, 1999a). It should be noted that the EPA's composite sorbent cost and performance estimates are based on a small number of pilot-scale system data and, hence, should be viewed with less certainty than cost and performance estimates based on PAC as the only sorbent.

The assumptions, approach, and the results of the mercury control cost analysis are described in detail in the subsequent sections of this memorandum. The remainder of this memorandum is divided into two parts: (1) Assumptions and Approach; and (2) Results.

(1) Assumptions and Approach

As noted earlier, the mercury control costs were calculated using spreadsheet analyses for the coal-fired electric utility plant population forecasted to be in existence in 2010 by the EPA's mercury MACT IPM™ run, HgMACT1d (EPA. 1999b). EPA-DOE assumptions about applicable mercury control technology and their cost and performance characteristics (EPA-DOE, 2000; DOE, 2000) were applied to the projected characteristics of the HgMACT1d coal-fired electric power plant population in 2010. Specifically, the following steps were adopted in calculating the mercury control costs for each required reduction scenario of the mercury control technology.

(i) First, the model forecasts (of generating capacity, generation, type of fuel consumed, pollution control retrofit decisions, etc.) of the EPA's mercury MACT IPM™ run, HgMACT1d, for 2010 were parsed to individual boilers and the coal-fired boilers were separated with their parsed characteristics.

(ii) For each coal-fired boiler with generating capacity greater than 25 MW, applicable mercury control technology was assigned based on (a) required mercury reduction and (b) pre-existing and retrofitted pollution control technology of the boiler, and the type and the sulfur content of the predominant coal type that the boiler consumed, in 2010 in the EPA's mercury MACT IPM™ run, HgMACT1d (EPA, 1999b). Table 1 provides the summary of existing pollution control technology and its applicable mercury control technology. Table 2 shows the types of coals used in the EPA's mercury MACT scenario IPM™ run, HgMACT1d, and their classification into high and low sulfur coals for the purposes of mercury control cost calculations.

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7 In this memorandum, all costs are reported in 1999 U.S. dollars.

Table 1. Summary of Applicable Mercury Control Technology

#	Coal Type	Existing Pollution Control Technology	Sulfur Grade: H- High; L - Low.	% of Total Boiler Capacity in 2010 in HgMACT1d[1]	Applicable Mercury Control Technology
1A	Bituminous	ESP	L	27.5%	ESP-4
2A		ESP/O	L	0.3%	ESP-4
3A		ESP+FF	L	0.0%	ESP-6
4A		ESP+FGD	H	9.9%	ESP-1
5A		ESP+FGD+SCR	H	8.7%	None
6A		ESP+SCR	L	12.7%	ESP-4
7A		FF	L	1.6%	(S) FF-2 *(ESP-4)*
8A		FF+DS	H	0.3%	(S) FF-2 *(SD/ESP-1)*
9A		FF+FGD	H	1.6%	ESP-1
10A		HESP	L	1.2%	ESP-6
11A		HESP+FGD	H	1.3%	ESP-3
12A		HESP+SCR	L	0.3%	ESP-6
13A		PMSCRUB+FGD	H	0.9%	ESP-1
14A		PMSCRUB+FGD+SCR	H	0.8%	None
1B	Bituminous	ESP	H	Included in percentages shown in cases 1A - 14A	ESP-1
2B		ESP/O	H		ESP-1
3B		ESP+FF	H		ESP-3
4B		ESP+FGD	L		ESP-4 w FGD
5B		ESP+FGD+SCR	L		None
6B		ESP+SCR	H		same as 1B
7B		FF	H		same as 1B
8B		FF+DS	L		(S) FF-2 *(SD/ESP-1)*
9B		FF+FGD	L		FF-2 w FGD
10B		HESP	H		ESP-3
11B		HESP+FGD	L		ESP-6 w FGD
12B		HESP+SCR	H		ESP-3
13B		PMSCRUB+FGD	L		same as 4B
14B		PMSCRUB+FGD+SCR	L		None
15	Lignite	ESP	L	0.9%	ESP-4, Same as Subbituminous
16		ESP+FF	L	0.4%	ESP-6
17		ESP+FGD	L	3.2%	ESP-4 w FGD, Same as Subbituminous case 22
18		FF+DS	L	0.0%	SD/FF-1, Same as Subbituminous
19		FF+FGD	L	0.7%	FF-2 w FGD, Same as Subbituminous
20	Subbituminous	ESP	L	15.5%	ESP-4
21		ESP+DS	L	0.2%	ESP-4
22		ESP+FGD	L	2.3%	ESP-4 w FGD
23		ESP+SCR	L	1.0%	ESP-4
24		FF	L	1.5%	FF-2
25		FF+DS	L	0.3%	SD/FF-1 *(FF-2)*
26		FF+FGD	L	1.0%	FF-2 w FGD
27		HESP	L	3.5%	ESP-6
28		HESP+FGD	L	0.2%	ESP-6 w FGD
29		HESP+SCR	L	0.9%	ESP-6
30		PMSCRUB	L	0.2%	ESP-4, same as ESP
31		PMSCRUB+FGD	L	1.4%	ESP-4 w FGD, same as 22

Notes: *(A) Existing Pollution Control Technology:* ESP=cold-side electrostatic precipitator (ESP); HESP=hot-side ESP; FGD=flue gas desulfurization (i.e., wet scrubber); FF=fabric filter; PMSCRUB=particulate matter scrubber; DS=dry scrubber.
(B) Applicable Mercury Control Technology: ESP-1=Powdered Activated Carbon Injection (PAC); ESP-3= PAC and polishing fabric filter (PFF); ESP-4=Spray Cooling (SC) and PAC; ESP-6=SC+PAC+PFF; FF-1=PAC; FF-2=SC+PAC; SD/FF-1=PAC; SD/ESP-1=PAC.
[1] Coal with a sulfur content greater than 1.8% (by weight) sulfur is considered "high sulfur" coal, and with a sulfur content of 1.8% or lower (by weight) sulfur is considered "low sulfur" coal.
Source: Excel file, "Hg control and cost assumptions for IPM, 8-30-00.xls," provided by DOE, August 2000 (DOE, 2000).

Table 2. Sulfur Grades of Coal

Coal Type	Coal Type Code	**Average Sulfur Content** (lbs of SO_2 per million Btu)	**Assigned sulfur grade for mercury control cost calculations** (L= Low sulfur; H= High sulfur)
Low Sulfur Eastern Bituminous	BA	1.0	L
Low Sulfur Western Bituminous	BB	1.0	L
Low Medium Sulfur Bituminous	BD	1.5	L
Medium Sulfur Bituminous	BE	2.2	L
Medium High Sulfur Bituminous	BF	3.0	H
High Sulfur Bituminous	BG	5.0	H
Low Medium Sulfur Lignite	LD	1.0	L
Medium Sulfur Lignite	LE	1.4	L
Medium High Sulfur Lignite	LF	2.1	L
Low Sulfur Subbituminous	SB	1.4	L
Low Medium Sulfur Subbituminous	SD	2.1	L
Medium Sulfur Subbituminous	SE	2.9	L

Notes:
Coal with a sulfur content greater than 1.8% (by weight) sulfur is considered "high sulfur" coal, and coal with a sulfur content of 1.8% or lower (by weight) sulfur is considered "low sulfur" coal. The sulfur content by weight was translated to SO_2 content per million Btu as follows:

Parameters and Assumptions:

Atomic weight of *sulfur* = 32; Molecular weight of SO_2 = 64 [= 32 (for sulfur) + 2 * 16 (=32 for O_2)].
Average heat content in 1 ton of bituminous coal = 23.5 million Btu (see Table 3 below for details)
Average heat content in 1 ton of lignite coal = 12.8 million Btu
Average heat content in 1 ton of subbituminous coal = 17.1 million Btu

Calculations:

Maximum allowable *sulfur* content in 1 ton of low sulfur coal = 36 lbs [= 2000 lbs/ton * 1.8%)
Maximum allowable SO_2 content in 1 ton of low sulfur coal = 72 bs [= 36 * (64/32)]
Therefore,

maximum allowable SO_2 content in 1 million Btu of low sulfur *bituminous* coal = 3.07 lbs
[= (72 lbs of SO_2/ton) / (23.5 million Btu/ton)];
maximum allowable SO_2 content in 1 million Btu of low sulfur *lignite* coal = 5.63 lbs
[= (72 lbs of SO_2/ton) / (12.8 million Btu/ton)]; and
maximum allowable SO_2 content in 1 million Btu of low sulfur *subbituminous* coal = 4.21 lbs
[= (72 lbs of SO_2/ton) / (17.1 million Btu/ton)]

Accordingly, for the purposes of mercury control cost calculations, medium high sulfur (BF) and high sulfur (BG) bituminous coals were conservatively considered *high* sulfur coals, although average SO_2 content of BF is less than 3.1 lbs per million Btu of coal; other bituminous coals were considered low sulfur coals. All subbituminous and lignite coals were considered low sulfur coals.

Source: “Analyzing Electric Power Generation under the CAAA,” Office of Air and Radiation, U.S. Environmental Protection Agency, March 1998 (Tables A4-3 and A4-12; EPA,1998).
Excel file, "Hg control and cost assumptions for IPM, 8-30-00.xls," provided by DOE, August 2000 (DOE, 2000).

(iii) For each boiler, boiler-specific unit mercury control (capital, and fixed and variable operation and maintenance (O&M)) costs were calculated using the cost functions provided by DOE (DOE, 2000). These functions are included in Attachment A to this memorandum. These unit costs differ by the amount of required mercury emission reduction, type of mercury control technology, and by the boiler characteristics (i.e., boiler generating capacity, heat rate, and the heat content of coal). To be consistent with the mercury control cost calculation methodology adopted for the prior IPM™ modeling of HgMACT1d scenario (EPA, 1999b), year 2000-boiler generating capacities were used for calculating these *boiler-specific* mercury control *unit* costs. Table 3 reports the average heat contents of different types of coal used for the mercury control cost calculations.

Table 3. Average Heat Content of Coal, by Coal Type

Coal Type	**Average heat content of coal** (MMBtu/ton)	**Average heat content of coal** (Btu/lb of coal)
Bituminous	23.5	11,740
Subbituminous	17.1	8,550
Lignite	12.8	6,400

Source: Calculated based on ICF's coal supply curves supporting EPA's Winter 1998 Base Case results presented in "Analyzing Electric Power Generation Under the CAAA," Office of Air and Radiation, U.S. Environmental Protection Agency, Washington, DC, March 1998 (EPA, 1998).

(iv) The boiler-specific unit costs were scaled by the share of their generating capacity in the total model plant capacity of the IPM™ run, HgMACT1d, in 2010, to arrive at unit costs for each model plant.

(v) For each IPM™ model plant, mercury control costs were calculated by multiplying that model plant's projected generating capacity and generation for 2010 and the model plant's mercury control unit costs. Specifically, the unit capital cost and the unit fixed O&M cost of each model plant were multiplied by the projected 2010 generating capacity of that model plant and the unit variable O&M cost of the model plants were multiplied by their projected generation in 2010. Then, all three components were added to calculate the total mercury control costs for that model plant.

(vi) Those coal-fired boilers that are projected to use bituminous coal, and are projected to install the pollution control technology combination of cold ESP, wet scrubber, and SCR by 2010, are assumed to reduce mercury emissions by approximately 95 percent and, therefore, are exempted from the requirement of installing additional mercury control technology (EPA, 2000; EPA-DOE, 2000; DOE, 2000). However, as noted earlier, for the purposes of the mercury control cost calculations, it was assumed that, under mercury MACT, these units would be required to operate their SCRs year-round. Therefore, for these units, the costs of operating SCRs during winter were calculated by multiplying their model plants' total winter generation (EPA, 1999b) by the high NO_x SCR's variable O&M cost of approximately 0.41 mills/kWh (EPA, 1998). The variable O&M cost for high NO_x SCR and the model plants' total winter generation were used as conservative estimates.

(vii) Next, mercury control costs of all the model plants were added to arrive at the total system-wide mercury control technology costs.

(viii) Last, "other" compliance costs related to mercury MACT regulation were added to the total system-wide mercury control technology costs to arrive at the total mercury control cost estimates for the hypothetical mercury MACT regulation, characterized by the IPM™ run, HgMACT1d. These other costs include (a) costs of repowering to, and building new, combined cycle plants to replace the generation and the generating capacity of retired coal plants, and (b) costs resulting from dispatch changes due to changes in the relative magnitude of total variable O&M costs of generating units due to mercury MACT regulation, including the costs of increased gas consumption, in the EPA's HgMACT1d scenario in 2010. Although IPM™ could generate reliable estimate of these "other" costs, these costs could not be accurately estimated through spreadsheet calculations.

Therefore, the difference (of approximately $138 million) between the EPA's original *total* mercury control cost estimate (of $2,266 million) and the EPA's original mercury control *technology* costs (of $2,128 million) calculated through spreadsheet analyses using EPA's original cost functions (EPA, 1999a) was added to the revised total system-wide mercury control technology cost estimates as an indicator of additional potential compliance costs of EPA's hypothetical mercury MACT scenario.[8] The actual estimate of "other" costs may, however, be different from $138 million added to the revised (PAC only and composite sorbent) mercury control technology cost estimates.

Further, it was assumed that the total (PAC only) mercury control technology costs would decline by about 40 percent, if a composite sorbent of lime and PAC was used (EPA, 2000). Hence, the composite sorbent mercury control technology costs were calculated by scaling down the total (PAC only) mercury control technology costs by 40 percent and by adding to this, the "other" compliance costs of $138 million.

The results of these cost calculations are discussed in the next section.

(2) Results

The mercury control costs for the 60 percent or greater and for the 80 percent or greater reduction scenarios are reported in Tables 4 and 5, respectively. As noted earlier, under these scenarios, mercury reductions range from (i) 60 to 95 percent, and (ii) 80 to 95 percent, respectively. Further, these reduction percentages correspond to the *combined* mercury removal efficiency of both the existing pollution control technology and the appropriate mercury control technology, as required under EPA's hypothetical mercury MACT scenarios.

The EPA's original mercury control cost estimates (EPA, 1999a) are also reported in Table 4 and these costs are compared to the revised mercury control cost estimates in this section of the memorandum. For purposes of comparison, as noted earlier, EPA's original *total* mercury control costs were divided into two components: (i) mercury control *technology* costs, calculated through spreadsheet analyses using EPA's original mercury control technology cost characteristics (EPA, 1999a) and (ii) *other* mercury MACT compliance costs, calculated as the residual of mercury control *technology* costs.

[8] *Other* mercury MACT compliance costs = Projections of *total* incremental mercury MACT regulatory scenario costs (Table 4-28; EPA, 1999a) − EPA's original mercury control *technology* costs calculated using spreadsheet analyses.

Table 4. Mercury Control Cost Estimates for the 60 Percent or Greater Mercury Reduction Scenario in 2010*

(million 1999$)

Cost Components	Original Mercury Control Cost Estimates with Composite Sorbent [a] (EPA, 1999a)	Revised Mercury Control Cost Estimates (PAC only)	Revised Mercury Control Cost Estimates (Composite Sorbent)
Mercury control technology Capital costs	401	398	
Mercury control technology Fixed O&M costs	58	693	
Mercury control technology Variable O&M costs	1,669	477[b]	
Other mercury MACT compliance costs [c]	138	138	138
Total	**2,266**	**1,706**	**1,079**[d]

Notes:

* Under this scenario, the mercury reductions range from 60 to 95 percent.

[a] The mercury control cost estimates were converted from 1990$ to 1999$ using a scaling factor of approximately 1.21. Mercury reductions ranged from 65 to 90 percent.

[b] Includes $49 million of variable O&M costs associated with winter operation of SCRs to comply with mercury MACT regulation.

[c] Other mercury MACT compliance costs = Total incremental mercury MACT regulatory scenario costs (Table 4-28; EPA, 1999a) - Total mercury control technology costs calculated using spreadsheet analyses.

These spreadsheet analyses are based on 2010 projections of generation and generating capacity of the IPM run, HgMACT1d (EPA, 1999b), and EPA's original cost and performance characteristics of mercury control technology (Appendix C; EPA, 1999a). These other mercury MACT compliance costs include (a) costs of repowering to combined cycle plants, and building new combined cycle plants, to replace the generation and the generating capacity of retired coal plants, and (b) costs resulting from dispatch changes due to changes in the relative magnitude of total variable O&M costs of generating units due to mercury MACT regulation (including costs of increased gas consumption). The same amount of "other" mercury MACT compliance costs have been added to the revised mercury control cost estimates with and without composite sorbent use as an indicator of additional unaccounted compliance costs. The revised total cost impacts of mercury MACT regulation simulated by IPM™ may differ from the revised total mercury control cost estimates reported in this table.

[d] The revised *total* mercury control costs for the composite sorbent use-scenario = revised mercury control *technology* costs for the composite sorbent use-scenario + $138 million of "other" mercury MACT compliance costs. The revised mercury control *technology* costs for the composite sorbent-use scenario were calculated by assuming that the mercury control technology costs would decrease by 40 percent (relative to the PAC only scenario) due to the use of composite sorbent (EPA, 2000).

Source:

"Analysis of Emission Reduction Options for the Electric Power Industry," Office of Air and Radiation, U.S. EPA . March, 1999 (EPA, 1999a).

Results of the EPA's IPM™ run, HgMACT1d, for 2010. http://www.epa.gov/acidrain/capi/ (EPA, 1999b).

Mercury control technology assumptions determined during EPA's meeting with DOE at EPA, Washington, DC, August 22-23, 2000 (EPA-DOE, 2000). See Excel file, "Hg control and cost assumptions for IPM, 8-30-00.xls," provided by DOE on August 30, 2000 (DOE, 2000).

Table 5. Mercury Control Cost Estimates for the 80 Percent or Greater Mercury Reduction Scenario in 2010*

(million 1999$)

Cost Components	**Original Mercury Control Cost Estimates with Composite Sorbent** [a] (EPA, 1999a)	**Revised Mercury Control Cost Estimates (PAC only)**	**Revised Mercury Control Cost Estimates (Composite Sorbent)**
Mercury control technology Capital costs	401	491	
Mercury control technology Fixed O&M costs	58	842	
Mercury control technology Variable O&M costs	1,669	1,276[b]	
Other mercury MACT compliance costs[c]	138	138	138
Total	**2,266**	**2,746**	**1,703**[d]

Notes:

* Under this scenario, the mercury reductions range from 80 to 95 percent.

[a] The mercury control cost estimates were converted from 1990$ to 1999$ using a scaling factor of approximately 1.21. Mercury reductions ranged from 65 to 90 percent.

[b] Includes $49 million of variable O&M costs associated with winter operation of SCRs to comply with mercury MACT regulation.

[c] Other Hg MACT compliance costs = Total incremental mercury MACT regulatory scenario costs (Table 4-28; EPA, 1999a) - Total mercury control technology costs calculated using spreadsheet analyses.

These spreadsheet analyses are based on 2010 projections of generation and generating capacity of the IPM run, HgMACT1d (EPA, 1999b), and EPA's original cost and performance characteristics of mercury control technology (Appendix C; EPA, 1999a). These other mercury MACT compliance costs include (a) costs of repowering to combined cycle plants, and building new combined cycle plants, to replace the generation and the generating capacity of retired coal plants, and (b) costs resulting from dispatch changes due to changes in the relative magnitude of total variable O&M costs of generating units due to mercury MACT regulation (including costs of increased gas consumption). The same amount of "other" mercury MACT compliance costs have been added to the revised mercury control cost estimates with and without composite sorbent use as an indicator of additional unaccounted compliance costs. The revised total cost impacts of mercury MACT regulation simulated by IPM™ may differ from the revised total mercury control cost estimates reported in this table.

[d] The revised *total* mercury control costs for the composite sorbent use-scenario = revised mercury control *technology* costs for the composite sorbent use-scenario + $138 million of "other" mercury MACT compliance costs. The revised mercury control *technology* costs for the composite sorbent-use scenario were calculated by assuming that the mercury control technology costs would decrease by 40 percent (relative to the PAC only scenario) due to the use of composite sorbent (EPA, 2000).

Source:

"Analysis of Emission Reduction Options for the Electric Power Industry," Office of Air and Radiation, U.S. EPA . March, 1999 (EPA, 1999a).

Results of the EPA's IPM™ run, HgMACT1d, for 2010. http://www.epa.gov/acidrain/capi/ (EPA, 1999b).

Mercury control technology assumptions determined during EPA's meeting with DOE at EPA, Washington, DC, August 22-23, 2000 (EPA-DOE, 2000). See Excel file, "Hg control and cost assumptions for IPM, 8-30-00.xls," provided by DOE on August 30, 2000 (DOE, 2000).

(a) Costs for the 60 percent or greater reduction scenario

The results in Table 4 indicate that the revised total mercury control cost estimates (for the PAC only scenario) are approximately $0.56 billion *lower* than the original EPA (1999a) estimates. While the capital costs are almost the same between these two scenarios, the revised mercury control fixed O&M costs are nearly 12-fold higher than the EPA's original mercury control fixed O&M cost estimates, calculated through spreadsheet analyses. In contrast, the revised variable O&M costs are less than one third of the EPA's original variable O&M cost estimates (EPA, 1999a). Two main reasons for the total mercury control technology cost differences are:

(i) In the EPA's original mercury analysis (EPA, 1999a), all coal-fired boilers with greater than 25 MW generating capacity were required to install mercury control technology. However, in the revised mercury analysis, DOE's mercury control technology cost and performance characteristics exempted some boilers from the requirement of installing mercury control technology. These exemptions were determined based on the required mercury reduction and the mercury removal efficiency of existing pollution control technology retrofitted to coal-fired boilers.

For example, *bituminous* coal-fired boilers retrofitted with cold ESP, wet scrubber, and SCR (which together account for about 9.5 percent of the total year 2000-coal-fired boiler capacity based on the population of coal steam generating units with capacities greater than 25 MW in the HgMACT1d scenario–see Table A in the attachment to this memorandum) are not required to install any additional mercury control technology, as it was estimated that this pollution technology combination could reduce mercury emissions as co-benefit by approximately 95 percent (EPA, 2000; DOE, 2000). However, it was conservatively assumed that these units would be required to operate their SCRs year-round. Similarly, for required mercury reductions up to 70 percent, *bituminous* coal-fired boilers retrofitted with wet scrubber and a particulate control device are exempted from installing additional mercury control technology (EPA, 2000; DOE, 2000). These exempted boilers together account for about 23 percent of the total year 2000-coal-fired boiler capacity based on the population of coal steam generating units with capacities greater than 25 MW in the HgMACT1d scenario (see Table A).

(ii) Further, DOE's unit variable O&M costs (DOE, 2000) are *lower* than the EPA's original unit variable O&M cost estimates (EPA, 1999a) for most of the model plants, which together account for over 95 percent of total coal-fired electric power generation in 2010.

However, in the composite sorbent use scenario, the revised total mercury control costs for 60 percent or greater reduction are over 50 percent *lower* than EPA's original total mercury control cost estimate of approximately $2.3 billion (EPA, 1999a).

(b) Costs for the 80 percent or greater reduction scenario

The results in Table 5 indicate that the revised mercury control cost estimates (in the PAC only scenario) are nearly $0.48 billion *higher* than the EPA's original cost estimates (EPA, 1999a). The higher mercury control cost estimates in this case could be attributed to DOE's *higher* capital and fixed O&M costs (DOE, 2000) than EPA's original cost estimates (EPA, 1999a). Specifically,

- DOE’s unit capital costs are *higher* than the EPA’s original unit capital cost estimates for model plants that account for over 75 percent of total coal-fired generating capacity in 2010;

- DOE’s unit fixed O&M costs are *higher* than the EPA’s original unit fixed O&M cost estimates for model plants that account for over 90 percent of total coal-fired generating capacity in 2010; and

- DOE’s unit variable O&M costs are *lower* than the EPA’s original unit variable O&M cost estimates for model plants that account for about 20 percent of total coal-fired generation in 2010.

However, in the composite sorbent use scenario, the revised total mercury control costs for 80 percent or greater reduction are about 25 percent *lower* than EPA’s original total mercury control cost estimate of approximately $2.3 billion (EPA, 1999a).

(c) 60 percent or greater reduction, vs. 80 percent or greater reduction, (PAC only) scenarios

The mercury control technology cost estimates in the 80 percent or greater mercury reduction scenario are over 65 percent *higher* than the mercury control technology cost estimates for the 60 percent or greater reduction scenario due to *higher* capital and O&M costs of mercury control technology associated with *higher* mercury removal efficiency. In addition, under the 80 percent or greater mercury reduction scenario, the *bituminous* coal-fired boilers with particulate matter control and wet scrubber technology, which were exempted from the requirement of installing additional mercury control technology under 60 percent or greater mercury reduction scenario, are required to install additional mercury control technology. Thus, part of the increase in the mercury control technology cost estimates in the 80 percent or greater reduction scenario (relative to the 60 percent or greater mercury reduction scenario) can be attributed to the costs of installing additional mercury control technology on the *bituminous* coal-fired boilers with particulate control and wet scrubber technology. These boilers together account for about 13.5 percent of the total year 2000-coal-fired boiler capacity based on the population of coal steam generating units with capacities greater than 25 MW in the EPA’s HgMACT1d scenario (EPA, 1999b).

ATTACHMENT A

TABLE A: Listing of Control Cases and Associated Sorbent Feed Concentrations for Different Levels of Mercury Control, and Costing Components

SORBENT FEED CONCENTRATION (Lb/Mmacf) Based on Hg Reduction %
(Required to calculate sorbent feed rate and sorbent injection capital cost)

#	Coal Type	Existing Pollution Control Technology	Sulfur Grade: H - High; L - Low.	% of Total Boiler Capacity	Applicable Mercury Control Technology	Hg Reduction (%)	60	70	80	90	95	CAPITAL COST BIRC COMPONENTS (From Capital Cost Sheet)	O&M COST COMPONENTS (From O&M Cost Sheet)
1A	Bituminous	ESP	L	27.5%	ESP-4	60, 80, 90	3		8	18.2		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
2A	Bituminous	ESP/O	L	0.3%	ESP-4	60, 80, 90	3		8	18.2		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
3A	Bituminous	ESP+FF	L	0.0%	ESP-6	60, 80, 90	1.7		4.6	10.6		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
4A	Bituminous	ESP+FGD	H	9.9%	ESP-1	70, 80, 90		0	6.2	24.4		(2) + (3)	1+ 2b + 2c + 2e + 2f
5A	Bituminous	ESP+FGD+SCR	H	8.7%	None	~95					0	None	None
6A	Bituminous	ESP+SCR	L	12.7%	ESP-4	60, 80, 90	3		8	18.2		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
7A	Bituminous	FF	L	1.6%	(S) FF-2 *(ESP-4)*	80, 90	3		8	18.2		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
8A	Bituminous	FF+DS	H	0.3%	(S) FF-2 *(SD/ESP-1)*	80, 90	1.8		5	11.5		(2) + (3)	1+ 2b + 2c + 2e + 2f
9A	Bituminous	FF+FGD	H	1.6%	ESP-1	70, 80, 90		0	6.2	24.4		(2) + (3)	1+ 2b + 2c + 2e + 2f
10A	Bituminous	HESP	L	1.2%	ESP-6	60, 80, 90	1.7		4.6	10.6		(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
11A	Bituminous	HESP+FGD	H	1.3%	ESP-3	70, 80, 90		0	2	7.6		(2) + (3) + (4)	1+ 2b + 2c + 2e + 2g
12A	Bituminous	HESP+SCR	L	0.3%	ESP-6	60, 80, 90	1.7		4.6	10.6		(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
13A	Bituminous	PMSCRUB+FGD	H	0.9%	ESP-1	70, 80, 90		0	6.2	24.4		(2) + (3)	1+ 2b + 2c + 2e + 2f
14A	Bituminous	PMSCRUB+FGD+SCR	H	0.8%	None	~95					0	None	None
1B	Bituminous	ESP	H	Included in percentages shown in cases 1A-14A	ESP-1	60, 80, 90	15.9		31.9	58		(2) + (3)	1+2b + 2c + 2e + 2f
2B	Bituminous	ESP/O	H		ESP-1	60, 80, 90	15.9		31.9	58		(2) + (3)	1+2b + 2c + 2e + 2f
3B	Bituminous	ESP+FF	H		ESP-3	60, 80, 90	5.7		15	33.5		(2) + (3)	1+ 2b + 2c + 2e + 2f
4B	Bituminous	ESP+FGD	L		ESP-4 w FGD	70, 80, 90		0	0.9	4		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
5B	Bituminous	ESP+FGD+SCR	L		None	~95					0	None	None
6B	Bituminous	ESP+SCR	H		same as 1B	60, 80, 90	15.9		31.9	58		(2) + (3)	1+2b + 2c + 2e + 2f
7B	Bituminous	FF	H		same as 1B	60, 80, 90	15.9		31.9	58		(2) + (3)	1+2b + 2c + 2e + 2f
8B	Bituminous	FF+DS	L		(S) FF-2 *(SD/ESP-1)*	80, 90	1.8		5	11.5		(2) + (3)	1+ 2b + 2c + 2e + 2f
9B	Bituminous	FF+FGD	L		FF-2 w FGD	70, 80, 90		0	6.2	24.4		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
10B	Bituminous	HESP	H		ESP-3	60, 80, 90	5.7		15	33.5		(2) + (3)	1+ 2b + 2c + 2e + 2g
11B	Bituminous	HESP+FGD	L		ESP-6 w FGD	70, 80, 90		0	0.47	2.25		(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
12B	Bituminous	HESP+SCR	H		ESP-3	60, 80, 90	5.7		15	33.5		(2) + (3) + (4)	1+ 2b + 2c + 2e + 2g
13B	Bituminous	PMSCRUB+FGD	L		same as 4B	70, 80, 90		0	0.9	4		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
14B	Bituminous	PMSCRUB+FGD+SCR	L		None	~95					0	None	None
15	Lignite	ESP	L	0.9%	ESP-4, Same as Subbituminous	60, 80, 90	2.4		9	21.4		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
16	Lignite	ESP+FF	L	0.4%	ESP-6	70, 80, 90		0.1	0.8	1.9		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
17	Lignite	ESP+FGD	L	3.2%	ESP-4 w FGD, Same as Subbituminous case 22	70, 80, 90		2.4	5.9	15.2		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
18	Lignite	FF+DS	L	0.0%	SD/FF-1, Same as Subbituminous	70, 80, 90		0.1	0.8	1.9		(2) + (3)	1+ 2b + 2c + 2e + 2f
19	Lignite	FF+FGD	L	0.7%	FF-2 w FGD, Same as Subbituminous	70, 80, 90		0.04	0.12	1.3		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f

TABLE A, continued

#	Coal Type	Existing Pollution Control Technology	Sulfur Grade: H - High; L - Low.	% of Total Boiler Capacity in IPM case	Applicable Mercury Control Technology	Hg Reduction (%)	60	70	80	90	95	CAPITAL COST BIRC COMPONENTS	O&M COST COMPONENTS
20	Subbituminous	ESP	L	15.5%	ESP-4	60, 80, 90	2.4		9	21.4		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
21	Subbituminous	ESP+DS	L	0.2%	ESP-4	60, 80, 90	2.4		9	21.4		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
22	Subbituminous	ESP+FGD	L	2.3%	Esp-4 w FGD	70, 80, 90		2.4	5.9	15.2		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
23	Subbituminous	ESP+SCR	L	1.0%	ESP-4	60, 80, 90	2.4		9	21.4		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
24	Subbituminous	FF	L	1.5%	FF-2	70, 80, 90		0.1	0.8	1.9		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
25	Subbituminous	FF+DS	L	0.3%	SD/FF-1 *(FF-2)*	80, 90		0.1	0.8	1.9		(2) + (3)	1+ 2b + 2c + 2e + 2f
26	Subbituminous	FF+FGD	L	1.0%	FF-2 w FGD	70, 80, 90		0.04	0.12	1.3		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
27	Subbituminous	HESP	L	3.5%	ESP-6	60, 80, 90	0.06		0.2	0.4		(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
28	Subbituminous	HESP+FGD	L	0.2%	ESP-6 w FGD	60, 80, 90	0.03		0.11	0.3		(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
29	Subbituminous	HESP+SCR	L	0.9%	ESP-6	60, 80, 90	0.06		0.2	0.4		(1) + (2) + (3) + (4)	1+ 2a + 2b + 2c + 2d + 2e + 2g
30	Subbituminous	PMSCRUB	L	0.2%	ESP-4, same as ESP	60, 80, 90	2.4		9	21.4		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f
31	Subbituminous	PMSCRUB+FGD	L	1.4%	Esp-4 w FGD, same as 22	70, 80, 90		2.4	5.9	15.2		(1) + (2) + (3)	1+ 2a + 2b + 2c + 2d + 2e + 2f

Notes:

[1] Coal with a sulfur content greater than 1.8% sulfur content (by weight) is considered "high sulfur" coal, and with a sulfur content of 1.8% or lower (by weight) sulfur is considered "low sulfur" coal
Sum of BIRC components must be multiplied by 1.3725 to obtain Total Control Capital Cost -- see Capital Cost Estimation Sheet.

[2] Boiler capacities correspond to the year 2000-generating capacities of *all* coal-fired steam boilers (with capacities greater than 25 MW) in the EPA's boiler population data set supporting the IPM™ modeling of EPA's hypothetical mercury MACT regulatory scenario, HgMACT1d (EPA, 1999a; EPA, 1999b).

Source: Excel file, "Hg control and cost assumptions for IPM, 8-30-00.xls," provided by DOE, August 2000 (DOE, 2000).

(A.1) MERCURY CONTROL CAPITAL COST ESTIMATION

Assumptions:

All costs are in December 1999 Dollars

Capital Cost units are $/kW
Bare Installed Retrofit Cost (BIRC) is provided for the following subsystems:

(1) Spray Cooling
(2) Sorbent Injection
(3) Sorbent Disposal
(4) New pulse-jet fabric filter (PJFF)

BIRC accounts for Process Equipment, Field Materials, Field Labor, and Indirect Field Costs

Total Control Capital Cost (TCCC) is calculated as follows:

TCCC = 1.3725 x BIRC

TCCC multiplier accounts for Engineering & Home Office Overhead/Fees, Process Contingency, Project Contingency and General Facilities.

BIRC Costing Algorithms:

<u>(1) Spray Cooling System</u>

Spray Cooing BIRC, $/kW = 6025 x ((GPM/215)^0.65) / MWe

Where,
GPM = Water Consumption, units = gallons/minute (GPM)
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

GPM is calculated as follows:

*GPM = 4.345E-7 x (Flue Gas Flow Rate, Lb/hr) x (Gas Temperature Change, F***)**

Flue Gas Flow Rate, Lb/hr = 1000 x MWe x (Heat Rate, Btu/Kw-Hr) x (Gas Flow Factor, Lb gas/ Lb coal) /(Coal HHV, Btu/Lb)

Gas Flow Factor, Lb gas/Lb coal = 15 for Bituminous Coal
Gas Flow Factor, Lb gas/Lb coal = 9 for Subbituminous Coal

Gas Temperature Change, F = 40 for Low Sulfur Bituminous Coal and Subbituminous Coal
Gas Temperature Change, F = 0 for High Sulfur Bituminous Coal

<u>(2) Sorbent Injection System</u>

Sorbent Injection BIRC, $/kW = 30 x (Sorbent Feed Rate, Kg/hr)^0.65 / MWe

Where,

Sorbent Feed Rate, Kg/hr = 4.54E-4 x (Sorbent Concentration, Lb/MMacf) x (Gas Flow Factor, acf/Lb coal) x (Heat Rate, Btu/kW-Hr) x MWe / (Coal HHV, Btu/Lb)

Sorbent Concentration, Lb/Mmacf = values are specified in Table A for each control application type

Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling

(3) Sorbent Disposal System

Sorbent Disposal BIRC, $/kW = 0.2 x (Sorbent Feed Rate, Kg/hr) / MWe

Sorbent Feed Rate, Kg/hr = same as previous calculation provided in (2) Sorbent Injection System

(4) New Pulse-Jet Fabric Filter System

PJFF BIRC, $/kW = 0.17 x (Flue Gas Volumetric Flow, ACFM)^0.8 / MWe

Where,

Flue Gas Volumetric Flow, ACFM = 16.67 x (Heat Rate, Btu/Kw-Hr) x MWe x (Gas Flow Factor, acf/Lb coal) / (Coal HHV, Btu/Lb)

Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling

(A.2) MERCURY CONTROL O&M COST ESTIMATION

Assumptions:

All costs are in December 1999 Dollars
Fixed O&M costs are in $/kW-Yr
Variable O&M (i.e., Consumables) costs are in mills/kW-Hr

Fixed and Variable O&M cost account for operating labor and maintenance labor and materials -- Does not include cost of consumables
Consumables costs account for cost of water, sorbent, sorbent disposal, and electricity.

(1) Fixed and Variable O&M Cost Estimation

Fixed O&M Cost, $/kW-Yr = [(296.25 / MWe) + (0.165 x Total BIRC)]

Where,

Total BIRC is the sum of the BIRCs calculated from the Capital Cost Sheet
MWe = Power plant net capacity, MW (e.g., 100)

(2) Variable O&M (i.e., Consumables only) Cost Estimation

(2a) Water

Annual Water Cost, mills/kW-Hr = 2.52E-2 x GPM / MWe

Where,

GPM = Water Consumption, units = gallons/minute (GPM)
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

GPM is calculated as follows (same calculations as provided in capital cost estimation sheet):

GPM = 4.345E-7 x (Flue Gas Flow Rate, Lb/hr) x (Gas Temperature Change, F)

Flue Gas Flow Rate, Lb/hr = 1000 x MWe x (Heat Rate, Btu/Kw-Hr) x (Gas Flow Factor, Lb gas/Lb coal) / (Coal HHV, Btu/Lb)

Gas Flow Factor, Lb gas/Lb coal = 15 for Bituminous Coal
Gas Flow Factor, Lb gas/Lb coal = 9 for Subbituminous Coal

Gas Temperature Change, F = 40 for Low Sulfur Bituminous Coal and Subbituminous Coal
Gas Temperature Change, F = 0 for High Sulfur Bituminous Coal

(2b) Sorbent (Powdered Activated Carbon only)

Annual Sorbent Cost, mills/kW-Hr = (Sorbent Feed Rate, Kg/hr) / MWe

Where,

Sorbent Feed Rate, Kg/hr = 4.54E-4 x (Sorbent Concentration, Lb/MMacf) x (Gas Flow Factor, acf/Lb coal) x (Heat Rate, Btu/kW-Hr) x MWe / (Coal HHV, Btu/Lb)

Sorbent Concentration, Lb/Mmacf = values are specified in Table 1 for each control application type
Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling

MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

(2c) Sorbent Disposal

Annual Sorbent Disposal Cost, mills/kW-Hr = 0.033 x (Sorbent Feed Rate, Kg/hr) / MWe

Where,

Sorbent feed rate is the same value calculated in 2b
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

(2d) Power Cost for Water Injection

Water Injection Power Cost, mills/kW-Hr = 0.163 x GPM/ MWe

Where,

GPM = Water Consumption, units = gallons/minute (GPM)
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

GPM is the same value calculated in 2a

(2e) Power Cost for Sorbent Injection

Sorbent Injection Power Cost, mills/kW-Hr = 3.4E-3 x (Sorbent Feed Rate, Kg/hr) / MWe

Where,

Sorbent feed rate is the same value calculated in 2b
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

(2f) Incremental Fan Power without New PJFF

Fan Power Cost without New PJFF, mills/kW-Hr = 9.165E-7 x (Flue Gas Volumetric Flow, ACFM) / MWe

Where,

Flue Gas Volumetric Flow, ACFM = 16.67 x (Heat Rate, Btu/Kw-Hr) x MWe x (Gas Flow Factor, acf/Lb coal) / (Coal HHV, Btu/Lb)

Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling
MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)

(2g) Incremental Fan Power with New PJFF

Fan Power Cost with New PJFF, mills/kW-Hr = 2.29E-5 x (Flue Gas Volumetric Flow, ACFM) / MWe

Where,

Flue Gas Volumetric Flow, ACFM = 16.67 x (Heat Rate, Btu/Kw-Hr) x MWe x (Gas Flow Factor, acf/Lb coal) / (Coal HHV, Btu/Lb)

Gas Flow Factor, acf/Lb coal = 280 for High Sulfur Bituminous Coal
180 for Subbituminous Coal and Low Sulfur Bituminous Coal with Gas Cooling

MWe = Power plant net capacity, units = MW, (e.g., 100 MWe)