

Preliminary Cost and Performance Models for Mercury Control at Coal-Fired Power Plants

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ABSTRACT

The U.S. Environmental Protection Agency (EPA) has announced it will regulate mercury emissions from coal-fired power plants, with proposed regulations to be issued in 2003. The feasibility and cost of achieving mercury emission reductions is thus a subject of considerable current interest. To assess mercury control options, the Integrated Environmental Control Model (IECM) developed for the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL) has been expanded to include performance and cost models for a variety of mercury control options. These preliminary models are based on a review of recent mercury information collection request (ICR) data, and on the results of pilot plant studies and other data sources employing carbon injection with and without flue gas humidification. Illustrative results using the IECM show that the feasibility and cost of achieving different levels of mercury reduction depend strongly on the fuel type and power plant configuration. In most cases, the presence of a flue gas desulfurization (FGD) unit or a selective catalytic reduction (SCR) system can have a significant (beneficial) impact on mercury removal efficiency and cost. However, because of limitations on the scale and coverage of available data, there is considerable uncertainty in current estimates of mercury control costs and capabilities. Current models and estimates will be refined as new data become available from on-going programs.

BACKGROUND

In December 2000, the EPA announced its intention to regulate mercury (Hg) emissions from coal-fired power plants under the air toxics provisions of the Clean Air Act Amendments (CAAA) of 1990. Coal-fired power plants are the largest industrial source of airborne mercury accounting for about one-third of U.S. anthropogenic emissions. Mercury controls would have to be installed by 2007 according to the current timetable.

Recent legislative proposals for multi-pollutant controls including mercury also have been put forth in the U.S. Congress. Most policy proposals would establish national

emission caps and allow emissions trading to minimize overall cost. Recent Congressional bills would require mercury reductions to a level of 90% below the 1997 level. While none of these multi-pollutant proposals have yet gained widespread Congressional support, they are nonetheless suggestive of the kinds of requirements that could be imposed on coal-fired power plants in the future.

EMISSION CONTROL OPTIONS

In general, the methods available to reduce or eliminate power plant emissions of mercury include: (1) switching to a cleaner fuel containing less of the undesirable constituent; (2) installing control technology to reduce or eliminate emissions; (3) improving power generation efficiency to reduce emissions per kilowatt-hour generated; (4) switching to a power generation technology with lower or no emissions; and (5) generating less electricity by reducing demand or by reducing the load factor of “dirtier” plants. The effect of these methods is summarized in Table 1.

Table 1. Power plant operations affecting mercury emissions

Power Plant Config and Operations Strategy	Effect on Mercury Emissions	
	Oxidized Mercury	Elemental Mercury
Conv. Coal Cleaning	Decrease (highly coal specific)	
Electrostatic Precipitator	Some decrease	Some decrease
Fabric Filter	Some decrease	Greater decrease
Wet SO ₂ Scrubber	Decrease	No Effect
Spray Dryer/Fabric Filter	Some decrease	Limited decrease
Carbon Adsorption System	Decrease (based on pilot-scale studies)	

The choice of a control strategy is typically dominated by the cost of alternative options. For existing coal-fired plants, coal switching and/or the installation of control technology historically have been the preferred approaches to environmental compliance for criteria air pollutants (SO₂, NO_x and particulates). For most existing plants, the most promising emission control option for reducing mercury emissions is activated carbon injection (ACI). This involves the injection of powdered activated carbon into the flue gas upstream of the particulate control device. Activated carbon is a specialized form of carbon produced by pyrolyzing coal or various hard, vegetative materials (e.g., wood) to remove volatile material. The technology has been proven in municipal waste combustors, but has not been directly scaled to utility flue gas applications. Mercury is adsorbed onto the sorbent and is then removed along with the fly ash in the fabric filter or electrostatic precipitator (ESP).

Moderate removal of mercury is accomplished by ash alone. Circulating the ash in a fluidized bed has been shown to enhance the removal of mercury, particularly with the addition of activated carbon to the circulating fluidized bed^{1, 2}. An additional benefit of circulating fluidized beds is the ability to add other sorbents to reduce acid gases³.

Once fuel is combusted, mercury can be identified in primarily two chemical states: elemental (Hg^0) and oxidized (Hg^{+2}). The ability of environmental control systems to capture the mercury is dependent on the forms of mercury in the flue gas. The data collected by EPA's ICR shows that wet scrubbers effectively remove oxidized mercury from the flue gas but are ineffective at removing elemental mercury. Efforts to convert the elemental mercury to an oxidized state using catalysts, such as those used in an SCR to reduce NO_x emissions, have resulted in higher capture rates of mercury in scrubbers⁴.

MERCURY EMISSION CONTROLS

Mercury control technologies, such as sorbent injection, have not yet been installed commercially at coal-fired power plants. However, data from smaller-scale tests indicate that mercury capture efficiency may be strongly affected by temperature, coal properties, and interactions with other environmental control systems. In the sorbent injection process, fine solids such as activated carbon are injected into the flue gas to adsorb or interact with gaseous mercury species. The adsorbed solids are then collected in a downstream particulate collector such as an electrostatic precipitator or fabric filter.

For existing coal-fired plants with only a particulate collector such as an ESP (the predominant plant configuration), mercury control is nominally achieved by injecting activated carbon upstream of the ESP. To achieve high levels of mercury control, substantial amounts of carbon injection are required, increasing the load on the particulate collector. Thus, a larger ESP, or a second collector (e.g., a baghouse filter), is needed to achieve allowable particulate emission levels if carbon injection is used for mercury control. The use of water injection to humidify the flue gas can reduce the activated carbon requirement and the associated load on the particulate collection device.

As indicated earlier, the presence of a wet lime or limestone FGD system also reduces emissions of air toxics including mercury. Thus, power plants already equipped with a wet FGD system can achieve mercury emission reductions at substantially lower costs.

For plants burning eastern bituminous coals, limited data from the ICR suggests that the presence of an SCR system together with a wet FGD system can eliminate altogether the need to inject activated carbon while achieving high levels of mercury control. On the other hand, for plants without a wet FGD system, the addition of SCR appears to have little or no effect on mercury capture efficiency. Additional research is clearly needed to better understand these observations.

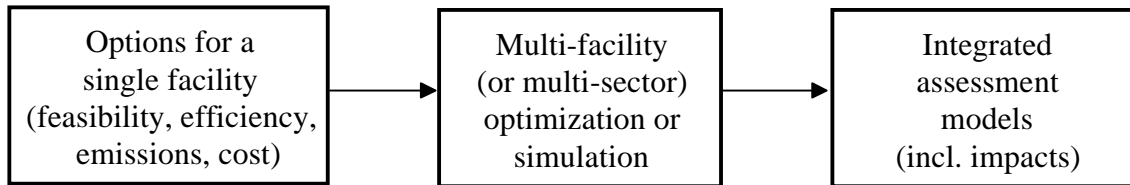
The particle size of the activated carbon also has been shown to influence the effectiveness of the sorbent injected⁵. Reducing the particle size will potentially increase the mass transfer between the gas and the solids by increasing the interfacial area of the sorbent. However, due to limited available data on particle size effects, the IECM does not currently consider particle size.

EVALUATING FEASIBILITY AND COST

Analyses of competing options for environmental control are typically carried out using computer models to simulate or optimize the electric utility response to new requirements

or policy proposals. Figure 1 depicts several types of modeling tools that are currently used for analysis. One type of model (to be elaborated in this paper) evaluates emission control options and costs at the level of a single plant or facility. This type of model is able to incorporate a fairly high level of technological detail and site-specific factors, while offering fast turnaround time and minimum data requirements. The plant-level model typically draws upon results of more detailed process-level models and data for individual plant components.

Figure 1. A hierarchy of models for policy analysis



Other models are designed to analyze multiple facilities and multiple time periods. These models are more complex and data intensive. Typically they treat power plants as aggregates of representative facilities of a given type or class. While these models have less technological detail, they incorporate a wider variety of interactions such as inter-fuel substitutions, energy demand forecasts, electric power dispatching, and macroeconomic impacts. The National Energy Modeling System (NEMS) used by the U.S. Department of Energy (DOE) for its Annual Energy Outlook⁶ is an example of this class of model.

Another class of models depicted in Figure 1 is integrated assessment (IA) models. These large-scale models link anthropogenic emissions to the environmental consequences and impacts of proposed policy measures. Typical applications of IA models include assessments of acid deposition, ambient ozone concentrations, and atmospheric CO₂ levels. IA models attempt to represent the complex couplings between emissions, atmospheric processes, and resulting impacts at the regional, national or global scale, for time periods ranging from decades to a century or more.

In principle, the different types of modeling and assessment tools shown in Figure 1 can draw upon one another to form an overall hierarchy of analytical capabilities able to address a broad spectrum of questions. In the present paper, the emphasis is on the “bottom-up” plant-level model. This perspective is needed to develop a careful understanding of plant-level factors that influence the feasibility and cost of multi-pollutant emission control strategies. It is important that large-scale “top-down” models in turn adequately represent such factors and interactions in their more aggregated representations of power plant technologies.

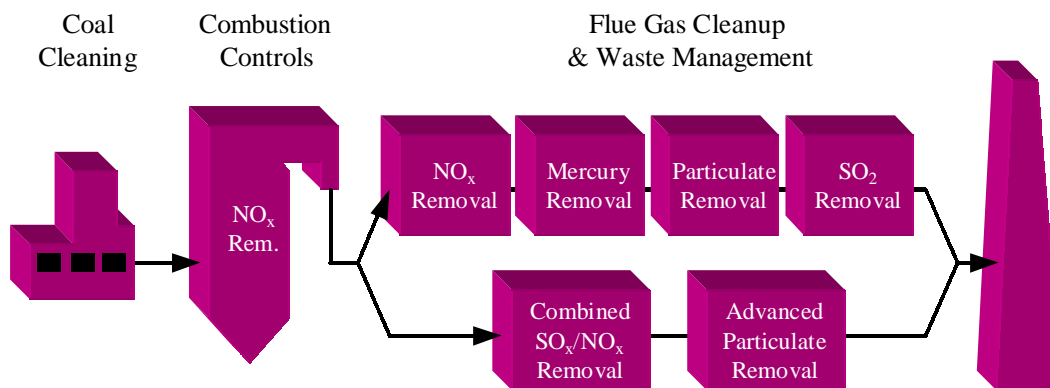
THE IECM MODELING FRAMEWORK

The Integrated Environmental Control Model (IECM) developed for the U.S. Department of Energy by Carnegie Mellon University provides plant-level performance, emissions and cost estimates for a variety of environmental control options for coal-fired power plants. The model is built in a modular fashion that allows new technologies to be easily incorporated into the overall framework. A user can then configure and evaluate a particular environmental control system design. Current environmental control options include a variety of conventional and advanced systems for controlling SO₂, NO_x, particulates and mercury emissions for both new and retrofit applications. The IECM framework now is being expanded to incorporate a broader array of power generating systems and carbon management options⁷.

Technology Performance Models

The building blocks of the IECM are a set of performance and cost models for individual technologies that can be linked together to configure a user-specified power generating system. Figure 2 shows a schematic of the integrated approach, which links the various technology types together. Each technology area represents one or more individual technologies. The process performance models employ mass and energy balances to quantify all system mass flows including environmental emissions. The energy requirements of each technology also are modeled and used to calculate the net efficiency of the overall plant. Details of current models can be found in published papers and reports⁸ and the software is publicly available⁹. Typically, each process performance model has approximately 10 to 20 key input parameters, depending upon the complexity and maturity of the technology.

Figure 2. Schematic diagram of the IECM technology types



Technology Cost Models

For each technology module in the IECM, associated cost models are developed for total capital cost, variable operating costs, and fixed operating costs. These elements are combined to calculate a total annualized cost based on a consistent set of user-specified financial and lifetime assumptions. Normalized cost results, such as costs per kilowatt (or kilowatt-hour) of net capacity, and the cost per ton of pollutant removed or avoided, also

are calculated. Cost models typically have about 20 to 30 parameters per technology, including all indirect cost factors and unit costs.

An important feature of the cost models is that they are explicitly coupled to the process performance models. Thus, capital costs depend on key flowsheet variables such as mass or volumetric flow rates, and important thermodynamic variables such as temperature or pressure. Annual operating and maintenance (O&M) costs also are linked to mass and energy flows derived from the process performance model.

Characterization of Uncertainties

An important feature of the IECM is the capability to rigorously characterize and analyze uncertainties. In addition to conventional deterministic (single-valued) calculations, the IECM allows any or all model input parameters and output results to be quantified probabilistically. This allows the interactive effects of uncertainties in many different parameters to be considered simultaneously.

Stochastic analysis thus provides quantitative insights about the likelihood of various outcomes, allowing users to more rigorously address questions such as:

- What is the likely cost (or cost savings) of a particular emission control strategy relative to other options? What are the potential risks such as shortfalls in performance or overruns in cost?
- Which control methods and technologies are most suitable for a given plant? Are there particular markets or applications that are likely to be most attractive for a given approach?
- Which parameters contribute most to overall uncertainty in performance and cost? What are the potential payoffs from targeted research and development to reduce key uncertainties?

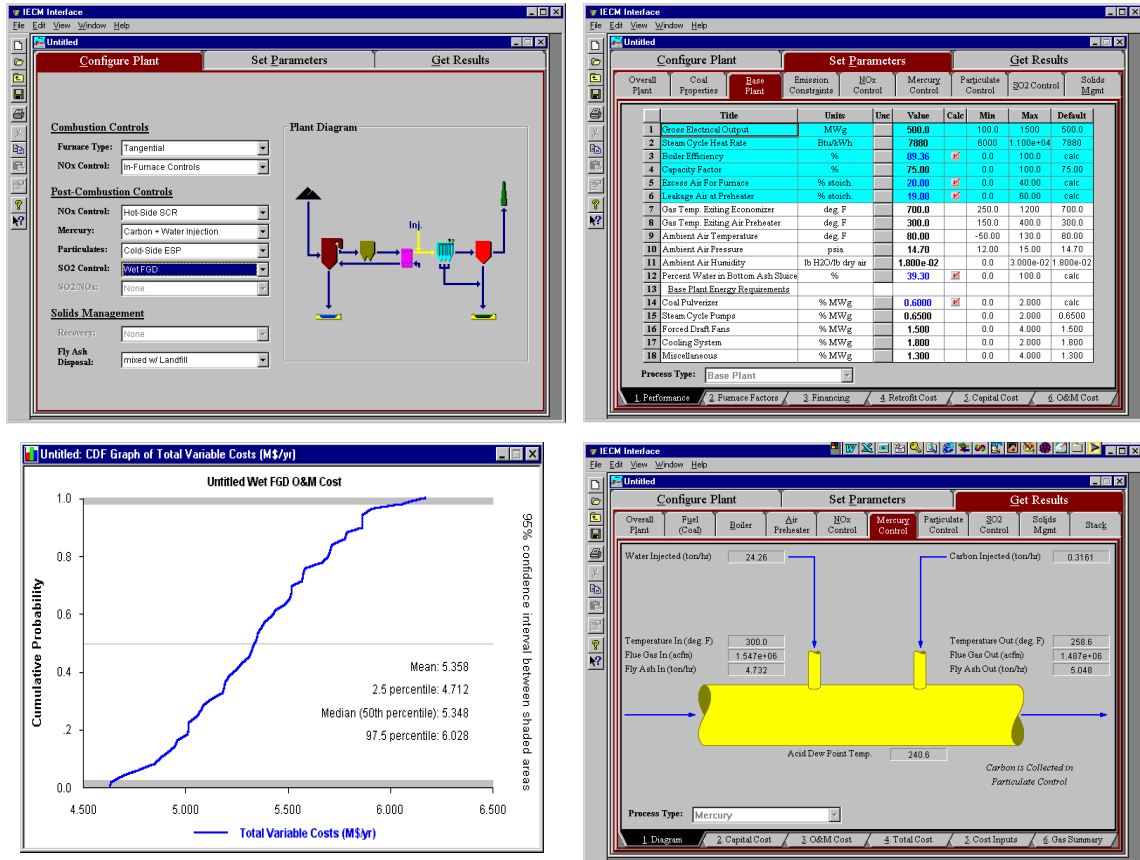
User-Friendly Operation

The IECM was designed to provide sophisticated modeling capabilities with quick turn-around time (seconds per run), transparency, and ease of use. A user-friendly graphical interface provides the capability to configure an analysis, set key parameter values (and their uncertainties), and get results in either probabilistic or deterministic form. A variety of graphical, pictorial, and tabular reports are available via the interface. Figure 3 shows several screen shots from the IECM's current graphical user interface.

MERCURY CONTROL MODULE

Activated carbon injection with the option of water spray injection is the first mercury capture module in the IECM. Version 3.4 of the IECM software was released in May 2001 with the addition of this new module. This technology enhances baseline mercury removal with additional removal to allow flue gas treatment to meet a user-specified emission constraint or percent reduction requirement.

Figure 3. Sample screens from the current IECM graphical user interface



The adsorption of mercury onto the activated carbon sorbent is a physical rather than a chemical process, whose effect increases as the temperature decreases. Spray cooling of the flue gas is an effective method for reducing the temperature of the flue gas stream. In most cases this reduces the amount of sorbent required for mercury capture and therefore the cost of mercury control. Understanding the potential effects of retrofitted controls that affect the baseline removal may further reduce the required sorbent and the total cost of pollution control.

The combination of base level controls and enhanced controls provide a useful approach for evaluating the relative merits of retrofitting a power plant to meet specific emission constraints, while minimizing the overall cost of abatement. As will be shown in the illustrative examples in the next several sections, the uncertainty features of the IECM add a unique dimension to the analysis of mercury control not provided by other models.

Performance Model

The IECM incorporates a dual approach to the removal of mercury in coal-fired power plants. The amount of mercury required for capture is determined by an emission constraint specified by the user. Because mercury is adsorbed in small amounts by

bottom ash and fly ash, each abatement technology incorporates a level of mercury capture in the absence of special treatment.

To reach higher levels of mercury capture, an activated carbon injection and optional water spray injection model has been added to the IECM. This additional injection system is referred to from this point as the mercury control module. The mercury control module is assumed to build on (add to) the baseline removal rate.

Mercury Emission Constraint

The level of removal of any flue gas constituent is determined by an emission constraint in the IECM. Nominally, the mercury capture is specified as an overall percentage reduction or removal efficiency. The level of removal refers to the total fraction of mercury that must be removed after the economizer and prior to the stack.

The mass flow rate of mercury emitted into the flue gas is directly proportional to the concentration of mercury in the coal. However, each power plant component between the economizer and the stack contribute to the removal of mercury even without the addition of a mercury module. Each of these baseline removals must first be determined and factored together before consideration of the mercury module. The necessary amounts of activated carbon and water are then calculated so as to remove any additional mercury necessary to meet the emission constraint.

Baseline Mercury Removal

Baseline mercury removal is defined as total removal of mercury without the addition of a carbon injection mercury module. These baseline removals are measured across the inlet and outlet of flue gas abatement technologies designed to remove other constituents in the flue gas, as shown in Equation (1). Examples of these baseline technologies include cold-side ESP, fabric filter, wet lime/limestone FGD, spray dryer, and SCR.

Note that mercury removal efficiency (%) is based on total (oxidized plus elemental) mercury removed from the flue gas and is defined as

$$\text{Mercury Removal Efficiency (\%)} = 100 \times \frac{(\text{Emission}_{in} - \text{Emission}_{out})}{\text{Emission}_{in}} \quad (1)$$

Measurements of mercury concentration in coal and removal efficiency across various flue gas cleanup systems were performed at coal-fired power plants as part of the ICR program initiated by EPA. The ICR results show that the removal is dependent on multiple factors such as coal type, temperature, and flue gas control device design. The ICR results for 1999 are summarized in Table 2.

Table 2. Summary of mercury in coal-fired power plants in 1999 (ICR data¹⁰)

Parameter	Median	Range (min – max)
Mercury content in coal		
Bituminous	0.12 ppm	0.01 – 0.45
Subbituminous	0.10 ppm	0.02 – 0.36
Lignite	0.22 ppm	0.02 – 0.42
Oxidized Mercury at Economizer		
Bituminous	70%	7 - 100
Subbituminous & Lignite	25%	3 - 88
Baseline removal in particulate collectors		
Boiler (total)	7%	0 - 10
Cold-side ESP (total)	31%	0 - 87
Spray Dryer & Fabric Filter (total)	39%	0 - 100
Mercury removed in wet FGD		
Elemental	0%	
Oxidized	100%	
Elemental Mercury Oxidized in an SCR	35%	

The “Range” column in Table 2 shows the high degree of uncertainty in the ICR data. This reduces the confidence in results based only on the median or nominal values typically used for analysis. Inclusion of the data ranges will be shown later to demonstrate the effect of uncertainty.

The forms of mercury present in the flue gas affect the adsorption of mercury on fly ash. Tests indicate that elemental mercury is adsorbed at a lower rate than oxidized mercury. The measurements in Table 2 indicate that mercury speciation can be changed by catalytic oxidation in an SCR unit, shifting the speciation from elemental to oxidized. Thus, the presence of a selective catalytic reduction system (SCR) in the IECM results in a 35% shift of the elemental mercury to oxidized mercury.

The IECM incorporates the median mercury parameters shown in Table 2 to report the expected total removal of mercury. Due to the effects of coal type on the oxidation state of mercury, the combination of technologies affects total mercury removal. Table 3 shows a summary of the total mercury removal for various combinations of coal rank and abatement technologies using the nominal values alone.

Table 3. Baseline mercury removal for various plant configurations

Technology	Baseline Mercury Removal (%)		
	Bituminous	Subbituminous	Lignite
ESP	31.0	31.0	31.0
SCR + ESP	31.0	31.0	31.0
ESP + FGD	79.3	48.3	48.3
SCR + ESP + FGD	96.2	54.3	54.3
SD + FF	39.0	39.0	39.0
SCR + SD + FF	39.0	39.0	39.0

Activated Carbon Injection Model

The relationship between the rate of AC injected for a given mercury removal efficiency is very important. The removal that is necessary to meet the constraint depends on the baseline mercury removal, the temperature of the flue gas and the type of coal fired in the boiler. The AC injection rate, flue gas temperature, and mercury removal efficiency were measured in pilot-scale tests and fitted to the form of Equation (1) with curve-fit parameters *a*, *b*, and *c*. Equation (2) can be used to calculate the AC injection rate (lb/10⁶ acfm) needed to achieve a specified mercury removal efficiency (%) for the control technology of interest at a particular temperature.

$$\text{Mercury Removal Efficiency (\%)} = 100 - \frac{\text{Baseline Removal (\%)} \times a}{[\text{ACInjection (lb/10}^6 \text{ acfm)} + b]^c} \quad (2)$$

For each technology for which pilot-scale test data were available, separate correlations of mercury removal efficiency and AC injection rate were determined for bituminous and subbituminous coals. These coals are predominantly used at utility boilers and, therefore, were chosen for the mercury module. Table 4 gives the coefficients derived from a facility burning an eastern bituminous coal.

Table 4. Regression coefficients used in Equation (2) for eastern bituminous coal

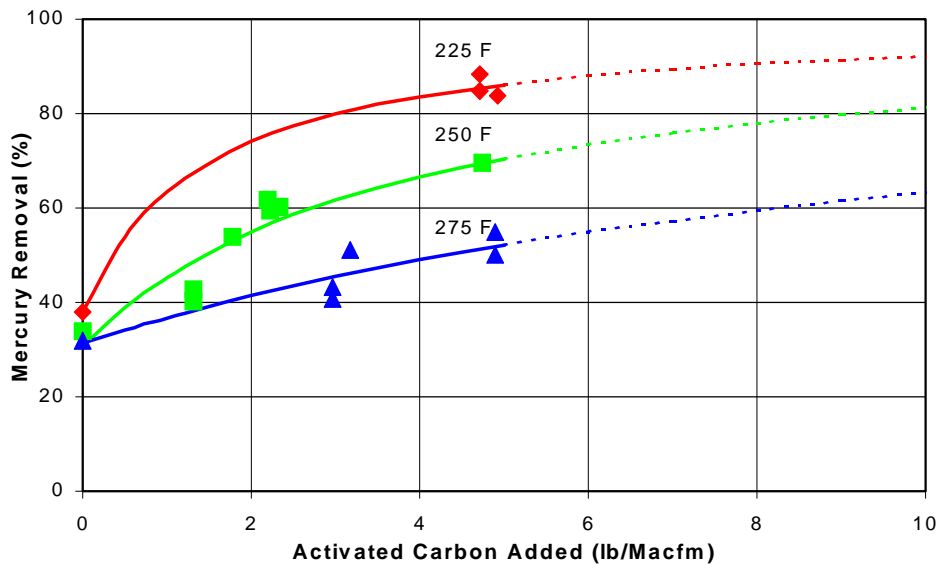
Parameter	225 °F	250 °F	275 °F
a	128.73	373.55	1143.2
b	1.4293	3.7206	11.485
c	1	1	1
R ²	0.99	0.85	0.89

The data and regression curves are shown together for the three temperature ranges in Figure 4. Carbon injection rates associated with other temperatures are interpolated from the injection rates of the adjacent temperature curves at the same removal efficiency.

The regression model depicted in Figure 4 has several important limitations that contribute uncertainty to any results obtained by using Equation (2):

- The lack of available full-scale data
- The lack of carbon injection rates for mercury removals in the 80-95% range (dotted region)
- Flue gas conditions (SO₃ and H₂O) to safely achieve a 225°F temperature are very unlikely

Figure 4. Mercury removal across an ESP for various operating temperatures (Eastern bituminous coal; 31% baseline mercury capture)



Substantial uncertainty results particularly in the mercury removal regions associated with activated carbon injection rates greater than 5 lb/Macfm.

Flue Gas Humidification Model

The IECM includes the option of humidifying the flue gas to lower its temperature and thus reduce the ACI requirement for a given level of mercury removal. The difference between the operating flue gas temperature and the approach to saturation temperature determines the amount of water injected into the flue gas. All calculations are based on the thermodynamic properties and state of the flue gas. If the operating temperature is above the approach temperature, the flue gas temperature is cooled to the user-specified approach above the dew point (nominally 18°F). The dew point is a function of the SO₃ and H₂O content in the flue gas and the pressure of the flue gas. Because of the effect of SO₃ concentration, high sulfur coals limit the amount of water that can be injected and subsequently require higher injection rates of activated carbon.

Illustrative Example

Here we define a base case power plant configuration to illustrate the effects of retrofit options added, coal switching, and the associated uncertainty in these and other default values. For the sections to follow, a coal-fired power plant burning a low sulfur eastern bituminous coal with a cold-side ESP is chosen as a base case. Table 5 shows the important input parameters defined in the IECM to describe this base case.

Table 5. Base case IECM input parameters used in the illustrative example

Coal Parameters	Value	Other Parameters	Value
Heating value (Btu/lb)	14,220	Gross Plant Size (MW)	500
Sulfur content (%)	0.6	Steam Cycle HR (Btu/kWh)	7880
Ash content (%)	3.8	APH Exit Temperature (F)	300
Moisture content (%)	2.2	Percent of SO _x as SO ₃ (%)	0.8
		Mercury Removal (%)	90

The effectiveness of activated carbon in mercury capture is inversely proportional to the flue gas temperature. As water is added to the flue gas, the temperature decreases. As shown in Figure 4, this reduces the amount of AC injected to achieve the desired mercury removal. Figure 5 shows the effect of water injection for the base case. The AC injection is decreased from 68 lb/Macfm to 38 lb/Macfm, a reduction of 44 percent. This substantial reduction is possible because of the low sulfur content of the coal and subsequent low concentration of SO₃ in the flue gas.

Figure 5. Carbon injection requirement as a function of water spray injection for the case study plant with 90% mercury removal

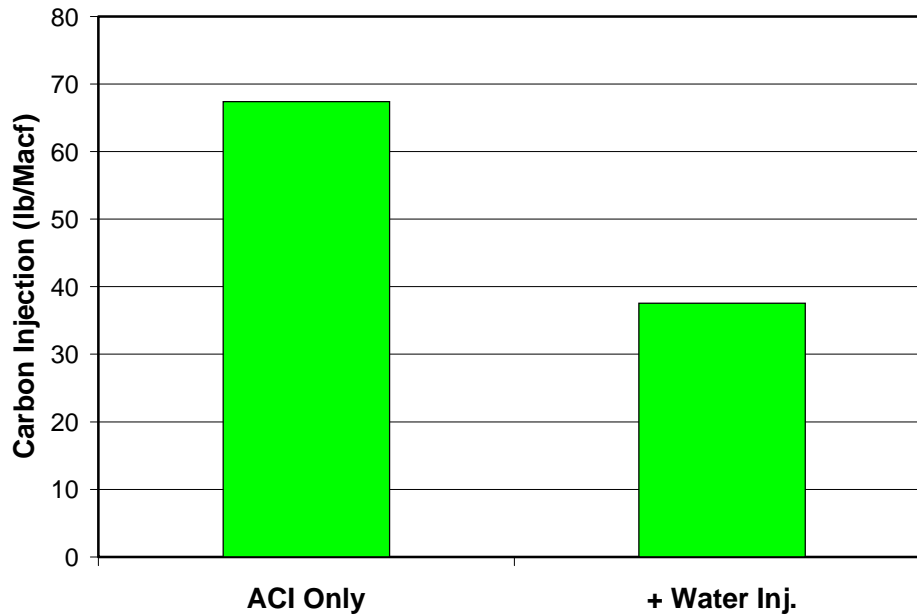
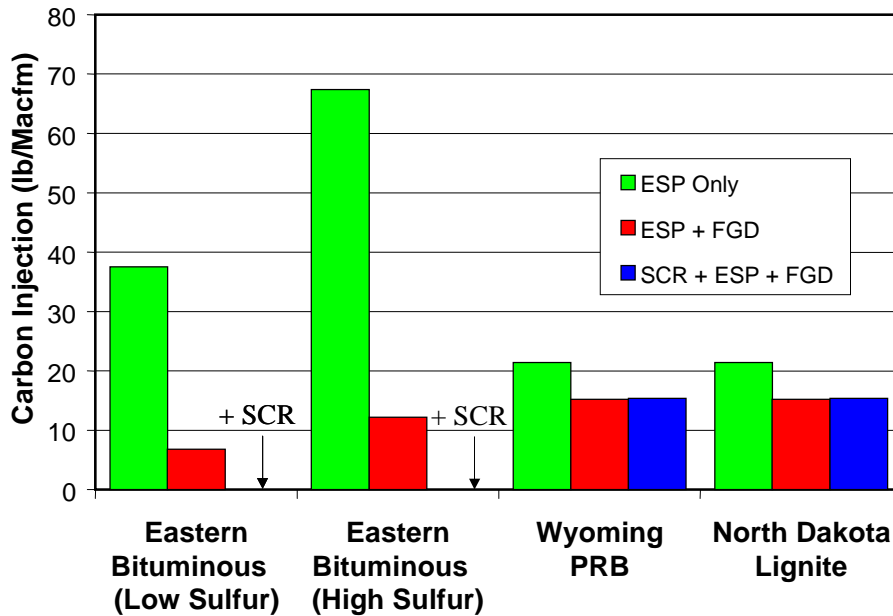


Figure 6 adds the effects of additional retrofit technologies. The plant configurations assume water injection to reduce the temperature within 18°F of the acid dew point. Four different coal types are compared: low sulfur bituminous coal (0.6% S), high sulfur bituminous coal (3% S), Wyoming subbituminous coal, and a North Dakota lignite.

Figure 6. Carbon injection requirement (with humidification) as a function of coal type and control technology for 90% mercury removal



Retrofit technologies compared include a wet limestone FGD and hot-side SCR. The carbon injection flow rates calculated by the IECM are based on the default values given in Table 3 and Table 5.

The effect of adding FGD and SCR is most dramatic for plants burning bituminous coals. This is due to the high percentage of mercury in the oxidized state and the effectiveness of wet scrubbing in removing the oxidized mercury. Subbituminous and lignite coals do not exhibit the same magnitude of reduced carbon injection although the ACI requirements are much lower to begin with. The addition of an SCR unit to an ESP-FGD system in the case of bituminous coal eliminates the need for activated carbon injection entirely while reducing mercury emissions by nearly 95 percent. For the subbituminous and lignite cases, however, the addition of SCR has no discernable effect on mercury control.

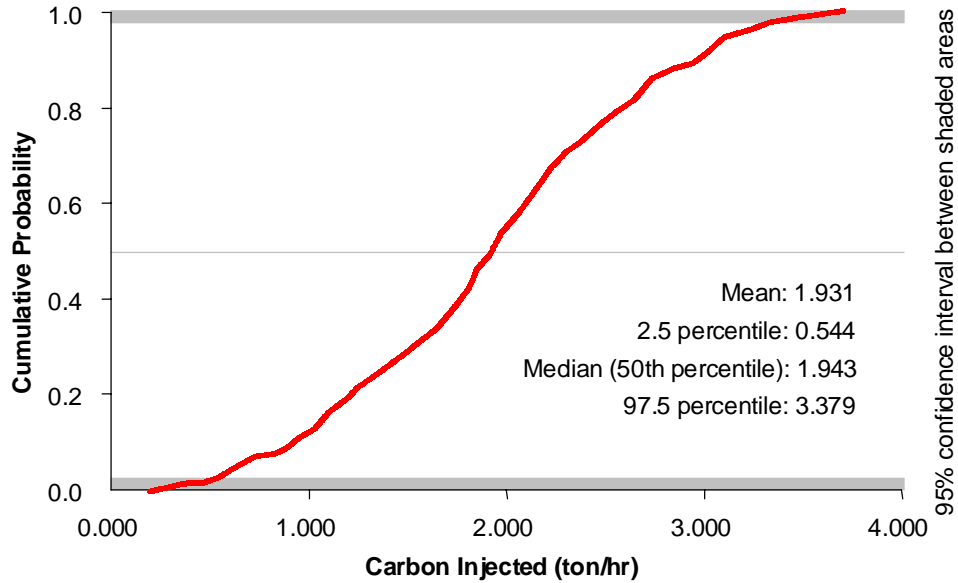
The cost of retrofitting mercury controls is also affected by other multi-pollutant interactions. Consider, for example, an SCR in combination with an ESP or with an ESP plus FGD. Because an SCR converts some SO₂ to SO₃, the ash removal in the ESP is enhanced. However, the additional SO₃ also increases the minimum flue gas temperature for a water plus carbon injection system due to the increased acid dew point temperature. This results in higher activated carbon requirements with higher costs.

Uncertainty Considerations

The ability to characterize uncertainties explicitly is a feature unique to the IECM. Up to one hundred input parameters at a time can be assigned probability distributions. When input parameters are uncertain, an uncertainty distribution for affected results is returned.

Such distributions give the *likelihood* of a particular result, in contrast to conventional single-value estimates.

Figure 7: Uncertainty of activated carbon injection (base plant)

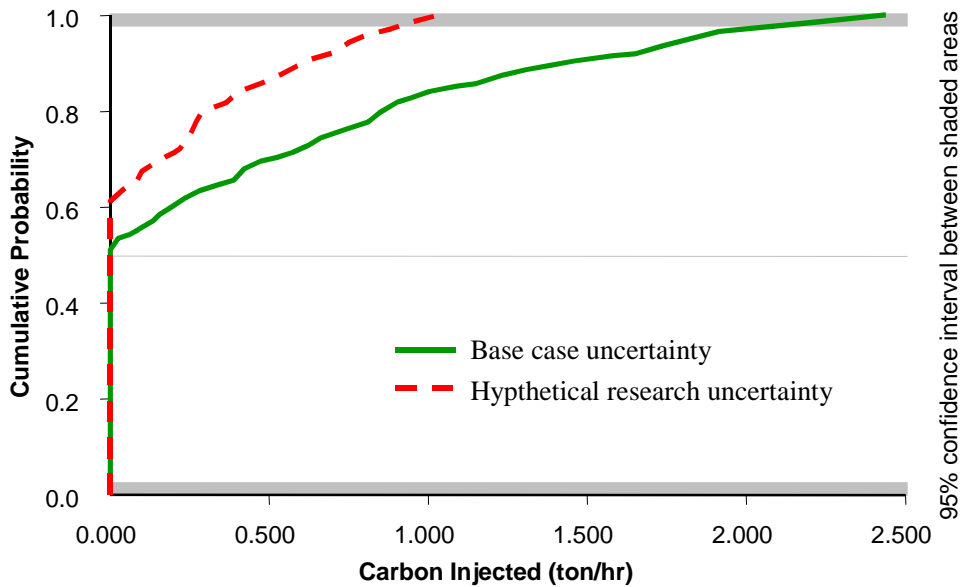


Triangular distributions were assigned to the baseline values shown in Table 3, with the end points spanning the ranges shown in Table 2. In addition, the approach to acid saturation limit was given a uniform distribution between 18°F and 30°F. The IECM randomly varies each of these uncertain input variables to generate the cumulative probability distribution shown in Figure 7. This figure demonstrates the uncertainty in the calculated carbon injection required to achieve 90 percent removal for the base case plant (ESP only). The 95 percent confidence interval spans a six-fold range from 0.54 to 3.38 tons/hr for this case.

As shown earlier in, no activated carbon is necessary for an SCR-ESP-FGD configuration burning bituminous coal based on the nominal values from Table 3 and Table 5. This represents the deterministic result. However, a probabilistic analysis similar to the one above shows the likelihood of no carbon injection for this case. This is exhibited in Figure 8. The results show a 53% chance of not needing carbon injection, but a 47% chance that it will be needed. The uncertain results also show that the injection required has a 20% chance of being higher than 1 ton year, but will be no high than 2.5 tons per hour.

A hypothetical research program that improves the characterization of the oxidation of mercury and the baseline mercury removal in an ESP can substantially reduce this uncertainty. Assume that the differences between the median and the extreme values shown in Table 2 are cut in half as a result of new research. This produces the hypothetical research uncertainty shown in Figure 8. This curve shows a 62% probability

Figure 8: Uncertainty of activated carbon injection (base plant with retrofit SCR and FGD)



that no carbon injection will be necessary, and reduces the worst case scenario to 1.0 ton/hr of carbon injected.

Economic Model

The cost of installing and operating an activated carbon injection system to remove mercury depends on a number of factors, such as power plant size, desired mercury removal efficiency, baseline removal efficiency, sorbent cost, sorbent disposal cost, and additional costs of particulate control equipment. To estimate these costs, the amount of sorbent required must first be calculated using the mercury performance module described previously. Most utilities use an ESP for particulate control. The presence of the ACI sorbent in the collected fly ash is assumed not to change the plant’s method of disposing the fly ash. The methodology to estimate the cost of this treatment involves the determination of the quantity of sorbent required to achieve a desired mercury removal efficiency and then an estimation of the appropriate size of the injection equipment.

Capital Cost Model

The IECM mercury control costs are based on a recent joint study performed by EPA, DOE/NETL, and Carnegie Mellon University¹⁰. The capital costs are broken down into seven separate process areas and are described in Table 6. The cost of each process area is a function of various stream flows and is summed to provide the total process facilities cost (PFC). Indirect cost factors using the EPRI Technical Assessment Guide (TAG)¹¹ are then applied to the PFC to give the total capital cost.

The total capital cost of ACI comprises only 20-25 percent of the total cost of the mercury control system. The remainder is composed of the O&M costs described next.

Table 6. Carbon injection system capital cost process areas

Process Area	Primary Stream Dependence
Spray Cooling Water	Water spray injection rate
Sorbent Injection	Activated carbon injection rate
Sorbent Recycle [‡]	Sorbent recycle rate
Additional Ductwork [‡]	Length of additional ducts
Sorbent Disposal	Activated carbon injection rate
CEMS Upgrade	Net plant capacity
Pulse-Jet Fabric Filter [‡]	Flue gas flow rate; Air-to-cloth ratio
<i>Process Facility Cost</i>	<i>(sum of all above)</i>

[‡] These process area costs are not currently used in the IECM.

O&M Cost Model

Table 7 shows the unit costs used for the IECM mercury module. The cost of activated carbon is the most important in the overall cost of the mercury removal module. On an annualized basis, it contributes nearly 75 percent of the total cost of the mercury capture technology. It is uncertain how the cost of activated carbon will change in the future in response to new mercury control requirements.

Table 7. O&M unit costs for the mercury module (\$1999)

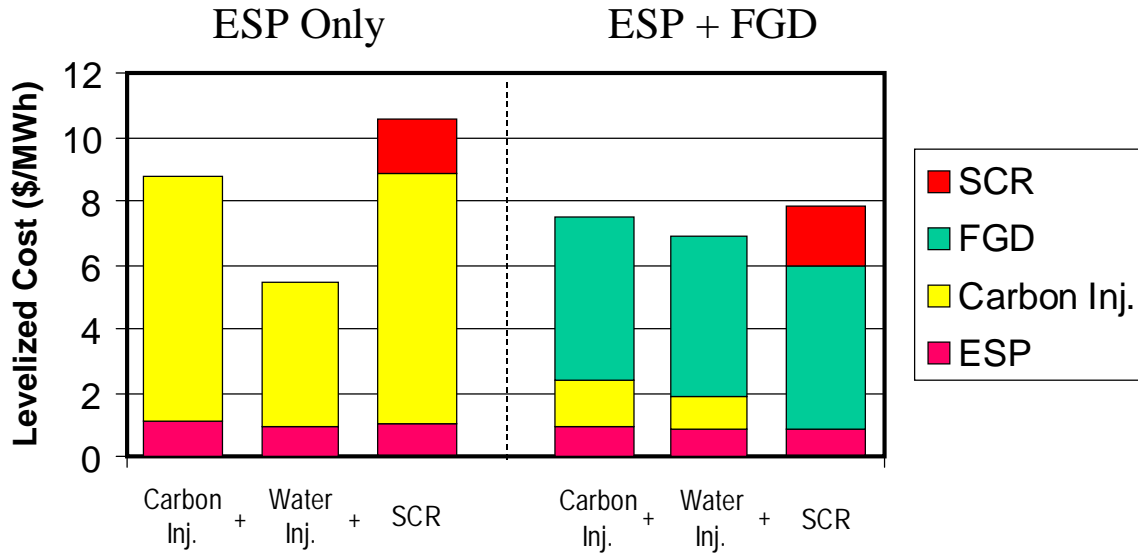
Parameter	Unit Cost
Activated Carbon (w/ shipping)	\$1,100 / ton
Waste Disposal Cost	\$11.44 / ton
Water Cost	\$0.70 / ton
Operating Labor Cost	\$25.00 / hour

Finally, the cost of waste disposal could increase dramatically if mercury-laden particulates are designated as hazardous wastes. This possibility adds further uncertainty to the cost of mercury capture.

Total Revenue Requirement

Capital costs, direct and indirect, are combined with the O&M costs and levelized over the life of the plant to assess the total revenue required. To illustrate the magnitude of carbon injection costs, the total levelized cost of abatement is shown in Figure 9 for the base case plant discussed earlier.

Figure 9. Deterministic results for a low-sulfur bituminous coal-fired plant (base case with retrofit technologies added). All costs in constant 1999 dollars.



The first bar shows the cost of mercury removal by carbon injection alone. The cost savings by injecting water to cool the flue gas is shown in the second bar, reducing the ACI cost from 7.6 to 4.5 \$/MWh. The cost associated with the ESP also decreased slightly due to the reduced disposal flow rate. The cost associated with the ESP also decreased slightly due to the reduced disposal flow rate. The third bar indicates that the effect of water injection is negated by the addition of a retrofit SCR system. The oxidation of SO₂ to SO₃ by the SCR catalyst increased the acid dew point sufficiently that water injection was not possible in this case.

The second set of bars considers the case of the base plant with an FGD system. The cost of carbon injection is greatly reduced from the ESP-only example. The addition of an SCR unit eliminates the need for carbon injection (based on the deterministic assumptions). The total cost with SCR is only slightly more than that with ACI in the presence of a wet FGD system.

CONCLUSIONS

The IECM is now capable of integrating mercury control into the existing suite of models that address criteria air pollutants. As demonstrated, the model effectively captures the multi-pollutant interactions that affect plant performance and cost. Additional discussions of multi-pollutant effects are presented elsewhere.¹² The costs of adding mercury control are shown to be dependent on the plant configuration, the flue gas temperature, and the fuel type being burned.

Although the mercury control module presented in this paper is preliminary based on limited data, it represents accurately what is currently known regarding the performance and cost of mercury control systems. As additional studies are performed and results published, the uncertainties in baseline removal and carbon injection system performance

and cost will be reduced. Future versions of the IECM will incorporate such results as they become available.

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