COMMENTS CONCERNING EPA'S INITIAL IPM MODELING FOR THE UTILITY MACT WORKGROUP

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J. Michael Geers, P.E. Cinergy Corporation 139 East Fourth Street Cincinnati, OH 45202	Claudia M. O'Brien Nicholas B. Gertler Latham & Watkins 555 11th Street, N.W. Suite 1000 Washington, D.C. 20004

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SUBMISSION OF THE UTILITY MACT WORK GROUP ON EPA'S IPM MODELING

Representatives of Industry and Labor participating in the Utility MACT Work Group appreciate this opportunity to provide input to EPA on the assumptions and results of the Agency's initial round of IPM modeling. This document is organized in three sections, each pertaining to a different aspect of the modeling. Specifically, we address:

1. Assumptions as to which we request clarification;

2. Assumptions that we request be modified; and

3. A request that the modeling focus on more runs in a shorter time horizon, and a request for access to certain model outputs and parameters.

EXECUTIVE SUMMARY

1. Assumptions as to which we request clarification

We request clarification of an IPM output that is counterintuitive and does not appear to reflect rational economic behavior. EPA's initial IPM modeling results predict that the reduction in coal-fired generation is inversely tied to the stringency of the mercury standard. In other words, the least stringent standard results in the greatest decline in coal usage. This result is counterintuitive to the point of appearing to be implausible. We request that EPA clarify this result and explain what aspects of the modeling brought it about.

- Specifically, the model run showed that use of western subbituminous coal is higher when it is subject to a more stringent mercury standard than a less stringent one. It also showed less total coal generation (and more total gas-fired generation) under the least stringent control scenario).

- Since the dispatching of electricity is based on the variable cost of generation, it simply does not appear plausible that, as the cost of plant operation increases due to mercury controls, the plant runs more.

- One explanation for this self-contradictory result may be that, while the modelers de-activated the allowance trading aspect of the IPM model, they may have inadvertently left the mercury allowance price in the dispatch equation for the IPM runs. Doing so would associate a financial benefit with mercury control, by valuing each unit of mercury reduction at the price of a mercury emissions allowance.

We ask for clarification of EPA's assumptions regarding ACI availability. We would like to know if EPA has imposed any constraints to the amount of Activated Carbon that could be applied to sources in the MACT timeframe.

We request clarification as to the baseline from which EPA is considering emissions reductions. Based on the initial modeling results presented to the group, it is not clear how EPA applied the percent reduction/emission rate to the population of utility units.

- A fundamental question we would like verified is whether EPA has applied its percent reduction to uncontrolled emissions (i.e. relative to what is in the coal) or against current emissions after considering the mercury reductions that are the cobenefits of existing controls on PM, SO_2, etc. This is a critical point and often is a source of confusion within the work group.

- It is our understanding from the April 3, 2002, workgroup meeting that, in its model scenarios and sensitivity analyses, EPA was expressing the reductions as a total reduction from potential uncontrolled coal emissions.

- In addition, we request that EPA identify what assumptions will be made relative to future emissions reductions, i.e. those due to the NO_x SIP Call.

We request clarification as to how modeled emissions rates correlate with percentage reductions. We also request an explanation as to how the percent removals and emissions rates were determined for the modeling runs. For example, in Case I, the high case uses a 90% removal or an emissions rate of 0.43 lb/TBtu. The medium case uses an 80% removal or an emissions rate of 0.79 lb/TBtu. A simple estimation would predict that if the permitted emissions rate were approximately to double (going from a 90% reduction to an 80% reduction), the emissions rate also would approximately double. This is approximately what happens between the high and medium cases. However, when reviewing the low case (70% reduction), the emissions rate balloons to 2.53 lb/TBtu.

2. Assumptions that we request be modified

These comments raise the following issues regarding assumptions in EPA's modeling that we believe are in error:

The 95% mercury control level attributed to the combination of SCR and FGD controls for all fuels cannot be substantiated based on available data and should be modified.

- The chemical process by which the combination of SCR and FGD would achieve a significant reduction in mercury emissions – the conversion of elemental mercury into the oxidized state – is subject to a number of physical and chemical limitations. These constraints are such that the process will not work for the entire range of fuels and plants employing this combination of controls.

- The oxidation of elemental mercury is heavily dependent upon the amount of chlorine in the flue gas. Lignite and subbituminous coals have low levels of chlorine (typically 250 ppm or less) and almost universally exhibit low levels of oxidation. Bituminous coals, on the other hand, have a wide range of chlorine contents (from 300 ppm to well over 1,000 ppm) and also exhibit higher levels of oxidation in the flue gas.

- While the SCR catalyst can increase the percentage of oxidized mercury in the flue gas, this process is subject to several constraints. The most critical constraint is that the process is very coal-dependent: Oxidation has been seen for some (but not all) bituminous coals, but is far more limited with subbituminous and lignite coals. Flue gas from subbituminous and lignite coals consistently has a higher fraction of elemental mercury. As a result, an SCR would have to oxidize a much higher fraction of mercury than for bituminous coals. This process would be made more difficult because of the lower chlorine content of the fuels

- The information available to date shows that the SCR oxidation reaction occurs more readily when the catalyst is fresh (i.e., has less than one ozone season of exposure). As a result, the catalyst would need to be replaced more frequently for mercury control than for the sole purpose of controlling NO_x.

- The ICR Part III testing does not provide a valid basis for attributing a significant control efficiency to SCRs because the effect of SCRs on mercury emissions cannot be isolated. It is not possible to conclude from the available data that SCR had a significant impact on mercury removal, because the units tested also were equipped with fabric filters and spray driers, and burned coal with high chlorine levels, all of which could have accounted for the observed high mercury reduction efficiency.

- Until a greater understanding of mercury speciation and oxidation chemistry is obtained, the assumption that 95% removal can be achieved by a unit employing SCR/FGD for all fuels is highly optimistic. For now, EPA should limit the assumed removal efficiency for this combination to 80% at most, and only for units burning bituminous fuels.

The 90% mercury control level attributed to the combination of SNCR and FGD controls cannot be substantiated based on available data and should be eliminated as a control option.

- The limited data on the performance of SNCR for mercury removal do not support a 90% removal efficiency. Of the three power plants subject to ICR testing that employed SNCR for NO_x control, in no case could a 90% removal efficiency be attributed to enhancement of mercury removal by the SNCR. Only one power plant reached a control level of 80%, but both EPA and EPRI have acknowledged that this result was most likely due to factors unique to the plant and unrelated to the SNCR.

- The other two plants studied were fluidized bed boilers that achieved no greater mercury removal with add-on SNCR than fluidized bed units without such controls.

- A recent EPRI research project showed that SNCRs do not affect mercury speciation or enhance the removal efficiency achieved by a cold-side ESP. There

are no data that would suggest a different result when an SNCR is used in connection with an FGD.

- EPA therefore should not assume that SNCRs provide any enhancement in mercury removal beyond what would be achieved with an FGD alone.

EPA's assumption of 80% removal for bituminous pulversized coal units with cold-side ESPs and FGD systems is overstated.

- It has been well documented that only oxidized mercury is removed to any significant degree by a wet FGD system. EPA has estimated that FGD scrubbers can capture approximately 90% of the oxidized mercury entering the scrubber. To achieve an 80% removal efficiency, approximately 90% of the mercury would need to exist in the oxidized form when it enters the scrubber. Even for high chlorine bituminous coals, this appears to be a highly optimistic assumption.

- Based on variations in chlorine content among bituminous coals, EPRI estimates that plants burning bituminous coal with cold-side ESPs and wet FGDs can achieve between 52% and 72% mercury removal, depending on the chlorine content of coal, suggesting that 60% would be a more reasonable estimate of mercury removal for this class of sources.

- It has been shown that some of the mercury entering a wet FGD system in the oxidized form can be reduced back to the elemental form. The elemental mercury cannot be captured and is subsequently emitted from the unit. This reaction occurs to different degrees based on the individual chemistry of that scrubber type. However, it appears that this reaction is more dramatic in magnesium-enhanced lime scrubbers than in other scrubber types. This phenomenon further supports use of a 60% removal efficiency assumption for this class of sources.

EPA has underestimated the cost and overestimated the effectiveness of activated carbon injection.

- EPA assumes 80% mercury removal for all plants using ACI. While a fabric filter / ACI combination could achieve approximately an 80% removal efficiency on a long-term basis, available data indicate that the combination of a high capacity ESP with an ACI cannot achieve much more than a 65% removal rate even in the most optimistic cases. EPA therefore should replace the single activated carbon removal rate assumption in its model (80% removal across the board) with two potential control options: one for plants with Cold Side ESPs, the other for plants with fabric filters. The first would allow no more than a 50%-60% reduction in existing Cold Side ESPs with activated carbon. The second, for plants with fabric filters, would be the installation of a supplemental bag filter or a COHPAC with activated carbon that achieves a higher percentage reduction, but not more than 80%. Thus, plants with fabric filters and ACI should be assigned an 80% removal efficiency. These assumptions should recognize that, because of

different activated carbon injection rates and ash disposal costs, the two scenarios will have different variable O&M rates.

- Water injection for spray cooling of flue gas has been found not to increase removal efficiency, while causing corrosion problems. Thus, spray cooling should not be included in the model as a control option.

- EPA's estimates of the average costs of ACI need to be revised to account for a number of factors that increase the expense of control.

  - Testing shows that, even under optimal conditions, cold-side ESPs cannot achieve 80% removal. This target removal rate therefore would require an upgrade to a COHPAC fabric filter, the costs of which should be included in overall estimates of the costs of control.

  - Most units would need to increase the capacity of existing ESPs to accommodate increased ash loading from activated carbon and its effects on electrical characteristics inside the precipitator;

  - Many units with fabric filters similarly would be required to upgrade those filters to accommodate the increased loading from ACI.

  - As discussed in greater detail below, unless the carbon is captured separately in a supplemental particulate control device, ACI would result in the mixing of fly ash and gypsum byproducts of power generation with carbon. This would render all but impossible the beneficial re-use of the significant portion of these products that currently are being marketed. Cost estimates therefore should include the foregone income from sales of these products as well as the newly-incurred cost of their disposal.

Use of activated carbon injection would result in the mixing of carbon with ash and gypsum, turning these marketable byproducts into solid waste. Many power plants market their byproducts of power generation: fly ash and bottom ash, as well as gypsum produced by SO_2 scrubbers. Use of ACI has been shown to render their beneficial re-use impossible.

- Power plants currently sell or give away their byproducts for use in concrete and wallboard manufacture and for other purposes. Each of these applications is governed by stringent standards of material purity.

- A pilot test at Wisconsin Energy's Pleasant Prairie plant demonstrated that the injection of even 1 lb/mmacf – far less than is needed for effective mercury removal – added sufficient carbon content to the ash to prevent any of these beneficial uses of plant by-products. As a result, large volumes of materials that are currently re-used would have to be landfilled.

- The need to landfill coal combustion products that would no longer be marketable would increase the cost of using activated carbon injection by $40-$50/ton of ash

(or gypsum) generated. EPA should incorporate this disposal cost into its IPM modeling assumptions for the cost of activated carbon injection, taking into account the fact that currently, not all power plants beneficially recycle their wastes.

3. We Request That EPA Explicitly Model the 2008 Compliance Year and Provide Access to Certain Model Outputs and Parameters

To perform modeling that most accurately portrays the impact of various MACT scenarios, we request that EPA perform model runs for a base case and the years 2008 and 2010.

- It is essential that a set of 'base' case outputs be developed for use as a template for evaluating various MACT scenarios. Therefore, the development of a base scenario that focuses on the critical timeframe of the MACT rule is paramount. To this end, we request that EPA run IPM for a base case of 2005, a policy year of 2008 to reflect the MACT compliance date, and 2010.

- Without this focus on near-term effects, the critical time period for compliance may be modeled in insufficient detail to illuminate the effects of competing policy alternatives.

We request that EPA provide certain input assumptions and data outputs. These data include both unit-level parameters and model-level issues.

We request the opportunity to participate in the development of EPA's ambient air quality modeling of mercury.

- We understand that EPA will use the outputs of IPM modeling as inputs for conducting regional-scale modeling of mercury loadings (REMSAD). In anticipation of this modeling effort, we would like to work with EPA to develop the basis for such an analysis.

- Specifically, we request that EPA make a baseline REMSAD run using emissions at current levels, and then a second run with all utility sources "zeroed out". These runs will allow an understanding of the total contribution attributed to utilities.

- Because IPM used model plants, it does not develop specific emissions for individual generating units. We are particularly interested in the process of converting the IPM outputs to the specific generating unit emissions that REMSAD will require.

Each of these issues is discussed in greater detail below.

I. REQUESTS FOR CLARIFICATION OF CERTAIN ASSUMPTIONS USED IN EPA'S MODELING

A. We Request Clarification as to an Aspect of the IPM Model Output that Does not Appear to Reflect Rational Economic Behavior

Coal Use Appears to Increase with the Stringency of Mercury Control

We request clarification as to a significant element of the IPM modeling results for different subcategorization scenarios that is counterintuitive to the point of appearing to be implausible. Specifically, EPA's initial IPM modeling showed the greatest reduction in coal-fired generation (and commensurate increase in natural gas generation) under the *least stringent* MACT standard modeled. That model run included subcategorization based on type of coal (*i.e.*, bituminous, subbituminous, lignite) and approximately a 95% confidence interval to set the MACT floor. Under this scenario, subbituminous and lignite plants are subject to substantially less stringent emissions standards than bituminous plants (35% removal or 10.8 lb/Tbtu for lignite, 30% removal or 4.32 lb/Tbtu for subbituminous and 70% removal or 2.07 lb/Tbtu for bituminous). Yet, the IPM model showed not only that coal generation decreases more than under more stringent scenarios, but also that use of western subbituminous coal *decreases* under this scenario, as compared to scenarios where it is subject to a more stringent standard.

Our concern is based on the belief that this output result appears to be wrong, insofar as it is highly counterintuitive. As explained in the documentation accompanying the IPM, dispatching of electricity is based on the variable cost of generation.[1] It does not seem plausible that, as the cost of plant operation increases due to mercury controls (and hence dispatch price increases), the plant runs more. For MACT control of mercury at any level, the proportion of gas generation should increase, because it avoids the cost of mercury control. But the IPM model predicts that gas generation increases more in the least stringent MACT mercury control case than under more stringent scenarios – even though the cost of controlling mercury should force more gas generation, not less.

The Model Appears to Assume a Trading Market for Mercury

The only phenomenon that we can imagine having given rise to this apparently self-contradictory result is that, while EPA deactivated the allowance trading aspect of the IPM model set-up, the Agency inadvertently may have left a non-zero mercury allowance price in the dispatch equation for the IPM runs. Under such a scenario, controlling emissions below the regulatory limit would give rise to marketable allowances that allow other sources to emit above the limit. A more stringent standard may have resulted in the modeled installation of control equipment that would allow sources to over-control their emissions and thereby derive a financial benefit from selling excess mercury allowances. Without considering this financial benefit of control in the dispatch, those units would be

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[1] U.S. EPA, "Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model," March, 2002, at 2-9.

expected to run *less*, rather than more, because of the increased variable O&M associated with controls.

Thus, what may have given rise to the apparent result seen in the IPM model – that units installing control equipment will run more because of lower dispatch prices – is the existence of a trading market with a cap for emissions. Given this assumption, the units with controls would dispatch first, and gas generation would become more attractive with higher mercury emissions. (It explains the nonsensical behavior of the market, which now is responding to the price signals of mercury allowances.) A similar phenomenon can be seen with respect to NO_x: Coal units with SCRs compete directly with combined-cycle gas-fired units if gas is $3/MBtu, but coal units without SCR are displaced by combined-cycle gas-fired units.

Of course we cannot be certain that this is the cause of the anomalous results that obtained. We request that EPA clarify this result and we would like the opportunity to explore further what aspects of the modeling brought about this apparently anomalous outcome.[2]

B. We Ask for Clarification of EPA's Assumptions Regarding ACI Availability; Specifically Whether EPA Has Imposed Any Constraints on the Amount of Activated Carbon That Could be Applied to Sources in the MACT Timeframe

EPA's IPM results project that approximately two-thirds of coal-fired electric generating units will install ACI by 2010.[3] We request clarification regarding EPA's assumption of the widespread availability of this technology, as well as the carbon feed required to operate it, in the 2008 time horizon for MACT compliance. Specifically, we would like to understand whether EPA's model included any constraints on the availability of activated carbon in the early years of the MACT program (*i.e.*, before 2010)? In addition, to the extent that EPA assumes an 80% removal efficiency for ACI, we request clarification of whether EPA has considered constraints on the ability of large numbers of units to design and construct COHPAC fabric filters between now and 2008.

C. We Request Clarification as to the Baseline Relative to which EPA Is Considering Emissions Reductions.

Based on the initial modeling results presented to the group, it is not clear how EPA applied the percent reduction/emission rate to the population of utility units. A fundamental question the group would like clarified is whether EPA has applied its percent reduction to uncontrolled emissions (i.e. relative to the total mercury that is in the coal) or against current emissions after considering the mercury reductions that are the cobenefits of

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[2] In part to illuminate this question, we are requesting in Part III. B. that EPA provide information on aggregate NO_x and SO_2 emissions and allowance prices and natural gas prices.

[3] *See* U.S. EPA, "Analysis of Alternative Subcategorization Options," Presentation to Utility MACT Working Group, May 13, 2002 at 5.

existing controls on PM, SO_2, etc. This is a critical point and often is a source of confusion within the work group.

It is our understanding from the April 3, 2002 workgroup meeting that, in its modeling scenarios and sensitivities, EPA was expressing the reductions as a total reduction from potential uncontrolled coal emissions. Using a simple example to illustrate the point, assume that currently the total mercury contained in the coal amounts to about 75 tons per year. In modeling case 1, the medium scenario applies an 80% reduction. This calculates to a total of 15 tons emitted per year – as compared to a total of 12 tons as shown in EPA's initial results. The low scenario in case 1 assumes only a 70% reduction. Multiplying 75 tons per year by 30% gives a total of 22.5 tons per year emitted – as compared with EPA's total of just under 14 tons.

D. We request clarification as to how modeled emissions rates correlate with percentage reductions.

We also request clarification as to how the percent removals and emissions rates were determined for the modeling runs. For example, in Case I, the high case uses a 90% removal or an emissions rate of 0.43 lb/TBtu. The medium case uses an 80% removal or an emissions rate of 0.79 lb/TBtu. A simple estimation would predict that if the permitted emissions rate were approximately to double (going from a 90% reduction to an 80% reduction), the emissions rate also would approximately double. This essentially is what happens between the high and medium cases. However, when reviewing the low case (70% reduction), the emissions rate balloons to 2.53 lb/TBtu, suggesting an error in the calculations.

Using the 1999 ICR data, approximately 19,080 TBtus of heat were input into coal-fired boilers. Using the 0.43 lb/TBtu emission rate given in the high scenario for case 1, this would yield about 4 tons of mercury emissions. Increasing the emissions rate to 0.79 lb/Tbtu under the medium scenario yields 7.5 tons, or not quite double. Further increasing to the 2.53 lb/TBtu given for the low case (70% reduction) yields 24 tons. This progression does not appear to be correct, nor is it consistent with EPA's projected tonnage emissions under Case 1 (12 tons for the medium case and 14 tons for the low case). We request that EPA clarify these results.

II. REQUESTS FOR MODIFICATION OF CERTAIN ASSUMPTIONS USED IN EPA'S MODELING

A. Existing Data from the ICR and other Sources Do Not Support the 95% Mercury Control Level Proposed by EPA for the Combination of SCR and FGD

EPA's initial modeling results presented to the Workgroup also were based on the assumption that the combination of SCR and FGD will allow units to achieve a 95% reduction in mercury emissions for all fuel types (bituminous, sub bituminous, and lignite). For this to occur, the SCR/ FGD combination would have to reduce mercury emissions in one of two ways: The SCR would have to cause additional mercury to be captured by either

the particulate control device (typically an ESP), or the FGD system. In either case the SCR would have to convert the majority of the elemental mercury into the oxidized state, because wet FGD systems only capture oxidized mercury while the elemental mercury is not captured in any significant amount. Research indicates, however, that this process is subject to several constraints that render the assumption of widespread 95% control unreasonable.

Research has found that for some coals, SCR catalysts could increase the percentage of oxidized mercury in the flue gas entering the downstream components. Increasing the amount of oxidized mercury versus elemental mercury in turn could result in higher mercury removal by the particulate controls and downstream SO_2 controls. However, this process is subject to several constraints. The most critical constraint is that the process is very coal-dependent: Oxidation has been seen for some (but not all) bituminous coals, but is far more limited with subbituminous and lignite coals. In addition, it appears that the reaction occurs more readily when the catalyst is fresh (i.e., has less than one ozone season of exposure).[4] This result implies that, in order to maintain the oxidation of mercury, catalyst would have to be replaced far sooner than it would for purposes of NO_x reduction. This represents an added cost of mercury control that should be considered in IPM modeling.

The ICR Part III testing does not provide a valid basis for attributing a significant control efficiency to SCRs. The ICR included two units in the spray drier/fabric filter (SD/FF) category – Birchwood and Logan – that fire high chlorine coals (900 ppm and 1500 ppm, respectively) and employ SCR for NO_x control. In addition, this category also contained two other plants using high-chlorine coals that do not employ SCR. High chlorine coals tend to produce high levels of oxidized mercury, which is usually well captured by the spray drier/fabric filter combination. All four units were similar and exhibited high levels of mercury control. From this data it is not possible to conclude that SCR had a significant impact on mercury removal, because in these cases the coal had high chlorine levels and the units were equipped with fabric filters and spray driers, all of which could have accounted for mercury reduction efficiency. Moreover, this data cannot be extrapolated to predict the performance of units using different coals with difference equipment configurations.[5]

Much of the pilot testing and full scale plant testing has been coordinated by the Electric Power Research Institute, and has been funded by several other entities, including EPA and DOE. EPRI is not yet able completely to predict the conditions under which an SCR catalyst will oxidize a significant percentage of elemental mercury. However, findings to date include the following:

- The oxidation rate is strongly dependent on space velocity (a smaller space velocity results in a larger catalyst bed size). Increasing SCR catalyst volume to achieve 90% total mercury removal in an SCR/ESP/FGD system could increase the installed cost of the SCR by 10-25% at units that already have a large catalyst for NO_X reduction due to high furnace-exit NO_X levels. However, for units equipped with a small catalyst due to low furnace NO_X levels, the cost increase could be 30-70%.

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4 *Id.* pg iii.

5 *Id.* pg 2-2.

- Flue gas chlorine content may be the key determinant of mercury speciation at the SCR and, hence, of the catalyst's oxidation effectiveness. Bituminous coals have a wide range of chlorine contents (from less than 300 ppm to over 2,000ppm) where as subbituminous and lignite coals are typically less than 250 ppm or less.

- For the two full-scale test sites where SCR provided significant mercury oxidation, the resulting concentration of non-elemental mercury in flue gas at the inlet to the ESP exceeded 90%. At these sites, the ESP/FGD system removed ~90% of the total mercury in the flue gas.

- Experience with PRB fuels showed a significant and rapid decline in elemental mercury oxidation rates with time. In other words, whatever ability the catalyst has to oxidize mercury in PRB flue gas is rapidly lost. It is plausible that this effect also occurs for bituminous fuels, but additional research is required to quantify this effect. If catalyst replacement frequency has to be increased, say, from an interval of 24,000 operating hours to 8000 hours or 4000 hours, SCR variable O&M costs would increase from slightly over 1 mill/kWh to nearly 4 mills/kWh at 8000 hours and 7 mills/kWh at 4000 hours.

As stated previously, EPA has assumed across the board that SCR & FGD will allow a unit to achieve 95% mercury reduction. Results of pilot and full-scale tests conducted to date have revealed there are significant gaps in the data. However, what is known indicates that it is not reasonable to extrapolate from the available data into areas where the data does not exist. Doing so would imply that units can achieve performance that is not physically possible. Examples of these data gaps include:

- Oxidation rates at SCR sites using a greater variety of coals (including low- and medium/high-sulfur eastern bituminous, western bituminous, and North Dakota and Texas lignite), catalyst types (vendors), and catalyst sizes;

- Oxidation rates as a function of time for eastern coal bituminous sites as well as additional full-scale PRB sites;

- Longer-term (i.e., one month) sustainable mercury oxidations at sites with SCR and FGD, including the effects of plant operations (e.g., coal switching, varying operating load); and

- A basic understanding of the flue gas chemistry that determines mercury speciation with or without SCR.

Until the a greater understanding of mercury speciation and oxidation chemistry is obtained, the assumption that 95% removal can be achieved by a unit employing SCR/FGD for all fuels is grossly optimistic. For now, EPA should limit this assumption at best 80% reduction and only for bituminous fuels.

B. The Existing Data from the ICR and Other Sources Do Not Support the 90% Mercury Control Level Proposed by EPA for the Combination of SNCR and FGD

The initial modeling results EPA presented at the May 13, 2002 Utility MACT Workgroup meeting included the assumption that the combination of SNCR and FGD will allow units to achieve a 90% reduction in mercury emissions. This degree of reduction could be achieved in only one of two ways: Either the SNCR would cause additional mercury to be captured by the particulate control device (typically an ESP), or it would oxidize sufficient mercury to allow for high levels of capture in the FGD system. Currently, however, there is little data available to characterize the effect of SNCR on mercury speciation and removal – and the data that *are* available suggest that SNCR does *not* enhance mercury capture in an ESP or result in additional oxidation of mercury. There also is no known data on the performance of a unit with both SNCR and FGD. EPA therefore should not assume that SNCRs provide any enhancement in mercury removal beyond what would be achieved otherwise by an FGD.

Three power plants subject to the ICR Part II testing employed SNCR for NO_x control. Of these units, Salem Harbor has a cold side ESP and no scrubber. AES Hawaii, and Stockton Cogen, on the other hand, are fluid bed combustion units with fabric filters for particulate control. In no case could a 90% removal efficiency be attributed to enhancement of removal efficiencies by the SNCR.

SNCR Has Not Been Shown to Enhance Mercury Removal in Pulverized Coal Units

Salem Harbor exhibited an unexpectedly high level of mercury removal of approximately 80%, but EPA and EPRI both acknowledged that even this removal rate is most likely due to factors unique to the plant and unrelated to the SNCR. EPRI's analysis points out that the facility has several atypical conditions that could contribute to high levels of removal, including:

- Low operating temperature in the ESP (265°F compared to 300°F or greater typical for most Cold Side ESPs), which likely enhance the oxidation of mercury;
- Uncharacteristically long ductwork between the air heater and ESP, resulting in long residence times that would allow for additional oxidation; and
- High levels of unburned carbon in the fly ash (15%-25%) that can sorb the mercury, thus improving removal efficiencies.

These factors create conditions under which high levels of carbon are injected in the ductwork for longer periods of time and at more opportune temperatures than is typical of similar facilities, resulting in potentially high levels of mercury reduction. In reviewing Salem Harbor, EPRI's research indicates "that [because] unburned carbon in the fly ash may remove mercury, it is not possible to estimate how much, if any, of this additional mercury

removal can be attributed to the SNCR."[6] In its review of the same data, EPA acknowledged the limited value of this information in predicting mercury control by SNCR by stating that,

> [i]t was reported that the fly ash from the boiler using SNCR contained unusually high levels of carbon. Because the data are available only for this one test, it is not known whether the high levels of Hg capture indicated by the test results are attributable to the high fly ash carbon content, the use of the SNCR system, a combination of both, or some other site specific factor.[7]

SNCR Has Not Been Shown to Enhance Mercury Removal in Fluidized Bed Units

The two other plants studied – AES Hawaii and Stockton Cogen – similarly provide no basis for concluding that SNCR is effective for mercury removal. The data indicate that the performance of these two units, both with fluid bed combustors, is consistent with predicted mercury removal rates based on the correlation for all plants in the FBC/FF category – including those without SNCR. Thus EPRI concluded that ***"these limited data suggest that SNCR does not have a significant impact on mercury removal"***.[8] In addition, because there are substantial differences between FBC/FF units and conventional boilers, the data from these units cannot be extrapolated to other control technologies categories, including cold-side ESPs. We in fact have previously recommended that they be subcategorized separately[9]

Finally, a recent EPRI research project evaluated the effect of an SNCR on a 160 MW tangentially fired unit using bituminous coal. This project was in part funded by EPA and DOE as well as receiving support from various other companies. The test measured mercury levels while the SNCR was operating and then again after the urea flow was shut off. The test was repeated with two different coals. In both cases the ESP removed little of the mercury and this finding was not impacted by urea injection, suggesting that the SNCR does not affect mercury speciation, and therefore is not expected to enhance mercury removal.[10]

In summary, there is little available data to characterize the effect of SNCR on mercury removal and no known data on the performance of a unit with both SNCR and FGD. EPA therefore should not assume that SNCRs provide any enhancement in mercury removal beyond what would be achieved otherwise by an FGD.

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6 Electric Power Research Institute "Impact of NOx Controls on Mercury Controllability, An Extract of EPRI Report #1004000 for Public Release", April 2002, pg 2-4.

7 US EPA "Control of Mercury Emissions from Coal-Fired electric Utility Boilers: Interim Report", March 2002, pg 6-49.

8 Electric Power Research Institute "Impact of NOx Controls on Mercury Controllability, An Extract of EPRI Report #1004000 for Public Release", April 2002, pg 2-4.

9 Geers & O'Brien, Basis and Rationale For Potential Subcategorization Of Coal Filed Electric Utility Steam Generating Units", March 8, 2002, pg.11.

10 Electric Power Research Institute "Impact of NOx Controls on Mercury Controllability, An Extract of EPRI Report #1004000 for Public Release", April 2002. pg 4-9.

C. All FGD Systems Are Not Equally Capable of Removing Oxidized Mercury

Wet flue gas desulfurization systems (wet FGD) have been the dominant technology for removing sulfur dioxides from flue gas. FGD systems were not originally designed for the purpose of removing mercury, but mercury reductions can occur as a co-benefit of scrubber usage. In its IPM model, EPA assumes the following mercury reductions for wet scrubbers:

	Bituminous	Sub-bituminous
Cyclone / Cold-side ESP / Wet FGD	55%	40%
Cyclone / Hot-side ESP / Wet FGD	55%	40%
Cyclone / Fabric Filter / Wet FGD	60%	5%
Pulverized Coal / Cold-Side ESP / Wet FGD	80%	35%
Pulverized Coal / Hot-Side ESP / Wet FGD	55%	30%
Pulverized Coal / Fabric Filter / Wet FGD	95%	70%

These assumptions about removal efficiencies generally appear reasonable, with one exception. EPA appears to have overstated the removal efficiencies that can be achieved by the bituminous pulverized coal/cold-sideESP/wet FGD combination, particularly for scrubbers using magnesium-enhanced lime. This is because EPA has overestimated the amount of oxidized mercury that is present in many bituminous coals. In addition, EPA appears not to have accounted for the reduction of ionic to elemental mercury that occurs in wet scrubbers, resulting in an overstating of the removal efficiencies for this class of sources.

FGD Mercury Removal Efficiency Depends on the Fraction of Mercury in Oxidized Form

Because it is insoluble in water, wet FGD systems do not remove elemental mercury. Oxidized mercury compounds are soluble in water and alkaline scrubbing solutions, making wet FGD systems moderately to very effective at removing this species of mercury. Therefore, the overall mercury removal efficiency is a function of the fraction of mercury that enters the scrubber in the oxidized form.[11]

In its October 25, 2000 assessment of mercury control strategies, EPA concludes that FGD scrubbers can capture approximately 90% of the oxidized mercury entering the scrubber.[12] To achieve an 80% removal efficiency, therefore, approximately 90% of the mercury would need to exist in the oxidized form when it enters the scrubber.[13]

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[11] This accounts for the large difference in the removal efficiencies that the IPM model attributes to similar plant configurations, depending on whether they burn bituminous or subbituminous coal. Subbituminous coals typically have lower chlorine content, resulting in lower percentages of oxidized mercury (and higher percentages of elemental mercury) and, hence, lower removal efficiencies.

[12] EPA, *Control of Mercury Emissions from Coal-fired Utility Boilers*, p. 4 (October 25, 2000).

[13] This assumes no mercury reduction in the ESP, a somewhat pessimistic assumption – as cold-side ESPs will remove some ionic mercury, but the general point still holds true.

Even for high chlorine bituminous coals, this appears to be a highly optimistic assumption. As has been discussed previously, bituminous fuels have widely varied chlorine contents, ranging from 300 ppm to over 2,000 ppm in some cases. Based on EPA's ICR data, EPRI predicts that coals with 300 ppm chlorine will have approximately 40% elemental mercury (and 60% oxidized mercury) in the flue gas; to achieve 90% oxidized mercury, the coal must contain approximately 1,500 ppm chlorine[14] – a very high chlorine content even for bituminous coals. Accordingly, EPRI estimates that plants burning bituminous coal with cold-side ESPs and wet FGDs can achieve between 52% and 72% mercury removal, depending on the chlorine content of coal.[15] The foregoing data suggest that 60% would be a more reasonable estimate of mercury removal for this class of sources.

Differences Among FGDs also Affect Mercury Removal

Moreover, there are different types of wet FGD systems, which use different reagents – and these different types of scrubbers in turn have varying mercury removal efficiencies. Some of the most common FGD systems use limestone, lime and magnesium-enhanced lime as reagents. There are considerable differences between the chemistry of magnesium-enhanced lime scrubbers and scrubbers that use limestone or even conventional lime. These differences not only determine the ability of the scrubber to remove SO_2 from the flue gas, but also the ability of the scrubber to remove mercury.

Scrubbers, however, cannot easily be converted between one type and another, because of the physical and chemical characteristics of each scrubber system. The amount of SO_2 that the scrubber liquor can remove is directly related to the amount of alkaline materials that are dissolved in it (*i.e.*, its alkalinity). Calcium-based compounds such as lime and limestone are relatively insoluble in water, but what does dissolve initially forms calcium hydroxide for lime scrubbers and calcium carbonate for limestone scrubbers. To remove high levels of SO_2, lime and limestone-based scrubbers have to spray very high levels of scrubber liquor into the flue gas. This is called the liquid to gas ratio or L/G. By comparison, the lime used in a magnesium-enhanced lime scrubber contains about 4-5% of magnesium by weight. Magnesium compounds are much more soluble in water. As a result, the slurry feed into a scrubber vessel is a mixture of calcium hydroxide and magnesium hydroxide. The magnesium allows the scrubber slurry to contain a much higher level of alkalinity. This higher alkalinity allows the scrubber to remove the same amount of SO_2 at a much lower L/G. For example, an L/G ratio for a magnesium enhanced lime scrubber may be one-fifth to one-tenth that of a limestone scrubber to achieve the same removal efficiency. Because a significantly lower amount of liquor flow is required, the size of a scrubber vessel, its pumps and other associated equipment is considerably smaller for a magnesium enhanced lime scrubber than any conventional lime or limestone scrubber. As a result, it is not practical to convert a magnesium-enhanced lime scrubber to using limestone.

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[14] EPRI, *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants*, p. 3-13 (September 2000).

[15] *Id.* at 3-36. EPRI's charts correlate removal efficiency to chlorine content of coal. Accordingly, these estimates are based on an assumption that bituminous coal has between 300 and 2,000 ppm chlorine.

Importantly, however, it is well-documented that some of mercury entering a wet FGD system in the oxidized form can be converted back to the elemental form in the scrubber itself. The mercury is then outgased from the slurry and is emitted from the stack. This phenomenon appears to be particularly prevalent with bituminous coals. The end result is that, while a scrubber will reduce the concentration of oxidized mercury, the concentration of elemental mercury may increase.[16] Moreover, while this reaction occurs to different degrees based on the individual chemistry of that scrubber type, it is significant enough to limit the overall removal efficiency of mercury by the scrubber. For example, one test showed the concentration of elemental mercury increasing by as much as 30% at a plant utilizing magnesium-enhanced lime, and reduction of 5-10% of the oxidized mercury back to elemental form appears common in many scrubbers. At least one vendor has researched a solution that could prevent this reduction reaction and thus increase total mercury removal. Initial pilot scale tested proved promising; however, full scale plant demonstrations showed that the process worked only on a limestone-based scrubber and not on one using magnesium-enhanced lime.[17]

In summary, then, scrubbers can convert oxidized to ionic mercury, thereby lowering overall mercury removal efficiencies. This phenomenon appears particularly pronounced among bituminous coal-burning plants, and plants with magnesium-enhanced lime scrubbers. Because it can have a pronounced effect of the overall mercury removal effiencies achieved by plants with wet scrubbers, EPA should reflect this phenomenon in its estimated removal efficiencies. However, we believe that approximately a 60% removal efficiency would adequately reflect this phenomenon – as well as the variability in chlorine content – for bituminous pulverized coal units with cold-side ESPs and scrubbers.

D. EPA Has Underestimated the Cost and Overestimated the Effectiveness of Activated Carbon Injection

EPA Has Overestimated ACI Removal Efficiencies

EPA assumes 80% removal for all plants using ACI. This assumption does not appear to be correct, based on recent pilot tests by one of the ACI vendors (ADA-Environmental), who presented their data at the May 13 Utility MACT Working Group meeting.[18] ADA-ES tested two plants, one with an ESP and burning subbituminous coal, and another with a COHPAC fabric filter following a hot-side ESP and burning a mixture of Eastern bituminous coals. While a fabric filter / ACI combination could achieve approximately a peak removal efficiency of 90%, the combination of an ESP with an ACI barely exceeded 65%.[19]

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16 G.T. Amrhein, et al, "Wet FGD Enhanced Mercury Control for Coal Fired Utility Boilers," (March 2002). at 14.

17 Id. at 15.

18 *See* Michael Durham, "Control of Mercury Emissions by Injecting Powdered Activated Carbon (PAC)," Presentation to Utility MACT Working Group, May 13, 2002, Research Triangle Park, North Carolina.

19 *Id*. at 10, 14.

ADA found that the addition of approximately 12 lb/mmacf added to the cold-side ESP resulted in a removal efficiency of approximately 65%. Increasing the amount of ACI to 20 lb/mmacf – or even beyond – resulted in only a marginal increase in removal.[20] Importantly, however, even these numbers represent high-end estimates of ACI removal rate, because the plant at which this pilot was performed (Pleasant Prairie Power Plant) has a new ESP with greater capacity than most in the industry, as well as extended ductwork residence time – both of which are expected to enhance mercury removal.

Moreover, the researchers had expected that the use of water injection for spray cooling of the flue gas to within 40°F of saturation would enhance the removal efficiency achieved from ACI. In fact, however, spray cooling did not enhance removal efficiencies. Moreover, the spray cooling caused corrosion problems at the plant. At Pleasant Prairie – like other plants that do not have dry or wet scrubbing – the stack exit temperature is kept above the acid dew point – the temperature where sulfuric acid begins to condense from a vapor to a liquid in the flue gas. In liquid form, the acid is very corrosive, so that acid condensation can cause corrosion of power plant components unless the components are specifically designed to be corrosion-proof. As flue gas temperatures are reduced in an effort to improve ACI control efficiency, there is an ever-greater likelihood that the acid dew point will be reached and localized areas of acid condensation will occur. In fact, this is exactly what happened at Pleasant Prairie, causing them to discontinue spray cooling to avoid significant structural damage to the plant's ductwork. It should be noted that industry has in the past thoroughly investigated lowering flue gas temperatures in general and using spray cooling in particular. Industry has previously found the benefits of lowering temperature were far outweighed by the problems caused.[21] These operational difficulties associated with spray cooling, coupled with the lack of effectiveness at enhancing mercury removal, strongly suggest that spray cooling as a means of improving capture efficiency should be removed from the model.

In contrast with ESPs, the fabric filter could achieve a peak removal of approximately 90% with the addition of about 4 lb/mmacf ACI at Alabama Power's E.C. Gaston plant. Again, however, adding substantially greater amounts of ACI resulted in only marginal increases in removal, suggesting that the removal "caps out" above a certain level.[22] Importantly, however, the experience at Gaston has shown that, while a 90% removal could be achieved as peak performance, the plant was unable to achieve this level of removal consistently throughout the test period. Moreover, as discussed below, the level of ACI required to meet a 90% removal overloaded the existing fabric filter, rendering such removal efficiencies non-viable in the absence of an upgrade to the fabric filter. Accordingly, an 80% removal rate attributed to an ACI / fabric filter combination is a more reasonable assumption.

The ADA representative concluded that the most important factor in determining mercury removal efficiency is the type of PM control employed by the plant:

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20 *Id*. at 10.

21 Geers & O'Brien, Basis and Rationale For Potential Subcategorization Of Coal Filed Electric UtilitySteam Generating Units", March 8, 2002, pg.48.

22 *Id*. at 14.

cold-side ESPs can achieve approximately a 60+% removal under optimal conditions such as those that were present during the pilot test. For the reasons stated above, fabric filters can be expected to achieve approximately an 80% removal. EPA should incorporate these revised removal efficiencies into its IPM modeling.

EPA Has Underestimated ACI Costs

EPA has estimated the capital cost of ACI at between $1/kW and $55/kW. At the May 13 Utility MACT Working Group Meeting, an EPA representative stated that the average cost is approximately $15/kW. High-end costs were reserved for plants with hot-side ESPs, which are assumed to need to retrofit with COHPAC fabric filters. We concur that it is appropriate to assume that plants with hot-side ESPs would need to retrofit with fabric filters before using ACI.

In fact, however, we believe that the costs likely are much higher than EPA has assumed. First of all, the ACI pilot testing shows that, even under optimal conditions, Cold-Side ESPs likely cannot achieve 80% removal. Thus, if EPA retains its 80% removal assumption, the costs of control would need to include the cost to upgrade the plant with a COHPAC fabric filter. Second, most ESPs have substantially less capacity than the one tested at Pleasant Prairie. Any marginal precipitators (*i.e.*, those that lack excess capacity) likely will require the addition of 1-2 fields to accommodate the increased ash loading from the injection of activated carbon. Alternatively, these plants may choose to add a COHPAC fabric filter to allow greater mercury removal efficiencies with less addition of activated carbon. In either case, these additional capital costs should be incorporated into the model.

Third, in the pilot test at Gaston, the researchers were required to limit the amount of activated carbon used to about 1.5 lb/MMacf to avoid overloading the COHPAC unit, which was unable to handle the extra particulate loading associated with the injection of activated carbon above this amount. At this concentration, however, even best-case removals could not exceed approximately 80%. We expect that many, if not most, existing fabric filters would encounter similar constraints. From a modeling perspective, EPA has two choices, then: either retain the existing modeling assumption of 80% removal, or incorporate the cost of upgrading of the COHPAC unit to handle the additional ash, if the Agency uses a removal efficiency above 80%.

As a result of the factors described above, we believe that $15/kW likely is an extremely low estimate of the capital cost associated with installing ACI – if the plant wants to achieve substantial mercury removals. We believe that incorporating the above assumptions will result in an average cost more in the range of $40/kW, although we have not made any exact calculations of the appropriate figure for each type of unit.

Moreover, we understand from ADA and others that the primary cost of ACI is O&M – the cost associated with the ACI that is injected into the unit. It is not clear whether EPA has assumed that ESPs will require approximately 5 times the amount of ACI as fabric filters, for a lower removal efficiency – but if not, this assumption should be incorporated into the model.

Finally, it is critical that EPA's cost model accurately reflect the financial impact, both in terms of disposal costs and foregone revenue, associated with mixing carbon with otherwise saleable ash products. As discussed further below, many power plants market their fly ash and bottom ash, as well as gypsum produced by SO_2 scrubbers. Use of ACI render the beneficial re-use of much of this material impossible and increasing plant operating costs. EPA's modeling has not accounted for these added resulting costs of control, while assuming that the fabric filter upgrades – which could potentially prevent such contamination – would not be necessary.

E. Use of Activated Carbon Injection Would Mix Carbon With Ash and Gypsum Turning these Marketable Byproducts into Solid Waste

Currently, approximately 32%, or 33 million tons, of coal combustion products generated annually are used in a variety of beneficial applications. Fly ash is used in concrete or cement applications, as highway base/subbase and fill materials, and in waste stabilization; bottom ash as fill material, anti-skid/traction agents; and flue gas desulfurization (FGD) gypsum in wallboard fabrication. Both EPA and the Department of Energy support this beneficial re-use of combustion products,[23] which lowers manufacturing and production costs while reducing energy use from displaced cement production, potentially accounting for substantial greenhouse gas benefits.[24] Installation of an activated carbon injection system to control mercury emissions, however, would change the characteristics and engineering properties of these coal combustion products in a manner that would preclude their continued beneficial use. To prevent this from occurring, facilities would have to expend additional capital to install a baghouse to prevent the carbon from mixing with the fly ash or scrubber gypsum.

The Re-Use of Coal Combustion Products Is Governed by Strict Composition Standards

The table below shows the specifications for material streams from coal-fired electric generating stations. Fly ash utilized as concrete filler material needs to comply with ASTM-C618. ASTM-C618 specifies the maximum acceptable carbon content for utilization in concrete filler (6%). It is necessary to limit carbon content in concrete because carbon reduces the strength of the concrete and causes premature failure.[25] State transportation departments typically tighten the maximum allowable carbon content as compared to the ASTM standard (3-4%). Two state DOT specifications are shown in the table below. In

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23 *See Wastes from the Combustion of Coal be Electric Utility Power Plants*, U.S. Environmental Protection Agency Office of Solid Waste and Emergency Response [EPA7, 530-SW-88-062, February 1988]; *Barriers to the Increased Utilization of Coal Combustion / Desulfurization Byproducts by Government and Commercial Sectors*, U.S. Department of Energy, Office of Fossil Energy [July 1994].

24 The American Coal Ash Association estimates that the use of fly ash to replace cement in concrete, by lowering energy consumption, has the potential to eliminate 10 to 14 million tons of CO_2 annually.

25 This is because carbon absorbs the air in the concrete. Air, however, increases the strength of concrete because it stops cracks from propagating. It also lowers the amount of Portland cement that needs to be used in the concrete.

reality, however, customers typically will not accept material that contains more than 1% carbon.

Moreover, it is important to recognize that the ASTM limits are based on the impact of unburned carbon from coal combustion on Portland cement concrete. Activated carbon, however, behaves much differently than unburned carbon and its impact on the reactions that produce concrete is significantly different than unburned carbon. Specifically, activated carbon is more "active" than unburned carbon and can affect the concrete air entraining agent at much lower levels. The ASTM limits on unburned carbon therefore are not directly applicable to activated carbon, and new limits would need to be developed.

Gypsum produced in wet FGD processes is used in construction materials and wallboard. A portion of the gypsum is also used to produce spackling or "mud" for wallboard installation. For cosmetic reasons, gypsum needs to be high purity and white in color. In addition, however, sufficient carbon content in the wallboard will cause the paper to peel, making the wallboard unusable. Accordingly, to be usable, the gypsum material quality needs to be high with very small amounts of carbon. Gypsum specifications for wallboard use also are set forth in the table below.

ACI Would Render Coal Combustion Products Unfit for Re-Use

The pilot test at Wisconsin Energy's Pleasant Prairie plant demonstrated that use of activated carbon injection to control mercury emissions will cause a carbon content sufficient to prevent any of these beneficial uses of power plant by-products. Indeed, even injection of 1 lb/mmacf caused the plant's ash to fail the foam index test for use in cement – yet the plant needed approximately 10 lb/mmacf or more to achieve even a 60% mercury removal efficiency, even with a new and state-of-the-art ESP installed on the plant. Moreover, given the small size of these carbon particles, it is reasonable to expect some amount of carry-through of this material, resulting in gypsum product degradation and potential foaming issues in plants equipped with scrubbers.[26]

The need to dispose of millions of tons of ash and scrubber gypsum that will no longer be used beneficially materially increases the cost of using activated carbon injection. The cost include not only the variable O&M to transport and landfill the ash, but also the capital cost of siting and constructing the additional required landfill space. Wisconsin Energy currently sells its ash from Pleasant Prairie at a price of approximately $10-$15/ton. They estimate that landfilling the same ash would cost $30-$35/ton, such that the total waste disposal cost increase associated with activated carbon injection is approximately $40-$50/ton of ash (or gypsum) generated. Another power company estimates that the additional carbon content in the fly ash generated by its plants would turn a marketable product into a waste stream to be disposed, at an annual cost of between $5 and $7 million. EPA should incorporate this disposal cost into its IPM modeling assumptions for the cost of activated carbon injection, taking into account the fact that currently, not all power plants beneficially recycle their wastes.

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[26] The introduction of activated carbon into FGD units can cause foaming of the scrubber liquor and ensuing backflow through the inlet ductwork, damaging plant components.

Carbon Content Specifications for Product Streams					
	anti-skid	concrete/construction	PaDOT	TxDOT	wallboard
ASH	0%	ASTM-C618 (<6%)	ASTM-C618 and <4%	ASTM-C618 and <3%	N/A
GYPSUM	N/A	see below*	N/A	N/A	see below*
		*gypsum specification is >=92% CaSO4 and <= 2% total inerts			
		inerts include combination of ash, limestone minerals and carbon			

III. REQUEST FOR MODELING OF BASE CASE AND COMPLIANCE YEAR, AND ACCESS TO CERTAIN MODEL OUTPUTS AND PARAMETERS

A. Request for an Additional Model Run for the 2008 Compliance Year

As the MACT Workshop process continues, we anticipate that additional IPM runs will be generated. Throughout this process it will be critical to be able to compare the 'base' case to the additional cases that will focus on the impacts of various MACT policies. We believe it is essential that an agreeable set of 'base' case outputs can be developed that would then be used as a template for all future comparisons. In our review of the current base case files posted on the EPA web page, we find that the analysis was apparently developed with a longer-term perspective than that pertinent in the MACT context, with modeling in five year increments from 2005 - 2030. Therefore, we urge EPA to re-run the base case, adding a model run for the 2008 compliance year between the 2005 and 2010 runs.

A greater focus on the near term is important because affected companies will have to wait until the final MACT rule is promulgated (*i.e.,* December 2004) before definitively knowing what emissions reductions will be required. They will have to complete the planning, engineering, and construction of required controls in only three years (by December 2007). In addition, some companies will need to alter their fuel purchasing and install equipment to accommodate new fuels. This short compliance period will have a major impact on power, fuels, pollution control and allowance markets that is presently ignored by the existing IPM run year structure. Therefore we recommend that the 'base' case with the Title IV and NO_x SIP Call policies be re-run with greater detail in the near term.

To address the need for greater near-term specificity to model the impact of various MACT scenarios, we request that IPM's model run year structure by modified to include an explicit modeling run for the 2008 compliance year, when the full impact of the MACT policy will be felt. We understand that the IPM model year structure includes runs for the years 2005 and 2010. In combination with the modeling for 2008, this structure should provide a good portrayal of the effects of MACT compliance on the industry, while providing a viable base case for model validation.

B. Request for Information on Model Outputs and Parameters

We recognize the complexities of modeling the electric power industry. EPA's method of aggregating a larger number of plants into a smaller number of "model plants' is a meaningful way to simplify the computational requirements. In addition, we understand that the model outputs are not necessarily appropriate for determining compliance options on an individual basis. However, we feel that, when aggregated, together the model results are very useful for larger numbers of units. To better understand the input assumptions of the IPM model runs and the data outputs, we request that EPA provide the following information in a spreadsheet, database or other useable format.

Unit-Level Parameters

1. A listing of ***model plant aggregations*** and the actual plants that comprise each. The current IPM files posted on the EPA IPM web site use a naming convention that we cannot interpret without additional explanation as to their format and content. Since the MACT standard will be applied on a unit-by-unit basis, we need to be able to map the aggregated model unit codes to specific, actual units. Therefore we request the code that associates model plants to the disaggregated units that comprise those model plants.

2. A listing of ***boiler-specific parameters and assumptions*** employed in the IPM modeling for the model plants including the following information:

    - Unit maximum capacity
    - Full load heat rate
    - Fuel types burned in base case
    - Existing emission rates and installed control technologies
    - Variable O&M and other available cost information

Model-Level Issues

In order to evaluate the full impact of various sub-categorization options and a wide range of future policy scenarios, a relatively detailed set of IPM outputs will be necessary. Therefore, where possible, we request the following information under both the EPA Base Case 2000 (which includes the NO_x SIP Call and Title IV SO_2 controls) and for all mercury MACT scenarios modeled:

1. ***Emissions and related information***

- Annual mercury, SO_2 and CO_2 emissions, as well as seasonal and annual NO_x emissions modeled for each NERC region and as a nation-wide total.

- Seasonal and annual SO_2 and NO_x allowance prices.

2. ***Compliance retrofit decisions***

   - Listing of the compliance retrofit decisions by NERC region resulting from the policy under review. Please include the number of MWs installed by technology, capital costs and O&M impacts of retrofits by NERC region.

   - Capacity of unit retirements by NERC region.

3. ***Possibility of coal substitution for compliance***

   - Indication of whether the model allows a unit to switch, *e.g.*, between bituminous and subbituminous coal.

   - Indication of whether the model assigns a coal type to a given unit as an input parameter or allows the unit to choose. If the latter, an explanation of the basis on which the unit would choose.

4. ***Fuel market information***

   - Coal characteristic assumptions used in IPM by coal rank.

   - A breakdown of coal consumption by type (grade or rank) by each NERC region and each coal producing region[27] for the years 2005, 2010 and 2020.

   - Delivered coal and natural gas prices and quantities for each NERC region for each year.

5. ***Power market information***

   - Annual generation by NERC region by fuel type.

   - Annual and seasonal power prices by NERC region (peak and off-peak).

   - Amount and type of new generation (*e.g.*, CT, CC, etc.) by NERC region.

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[27] These regions are Midwest, Northern Appalachia, Central Appalachia, Southern Appalachia, Gulf Coast, PRD, North Dakota Lignite and Other West.

C. Requests Pertaining to Mercury Ambient Air Quality Modeling

We understand that the MACT process will include mercury air quality modeling using a regional scale modeling system such as REMSAD, CMAQ or PMCAMx as part of the utility MACT workshop and rulemaking process. Input data on mercury emissions for this air quality modeling analysis will likely come from the IPM results. In anticipation of this air quality work, we would like to work with EPA to develop a workable platform for such an analysis.

We would be interested in reviewing any modeling protocols that EPA has developed for this work as well as any existing public modeling studies or applications in which EPA, state or other entities, has conducted such mercury modeling. We also would be interested in the opinion of EPA modelers whether they consider such work products "proof of concept" modeling or as meeting the more rigorous standard for "regulatory approvable" modeling.

Because IPM used model plants, it does not develop specific emissions for individual generating units. REMSAD, however, requires data on the emissions of individual units. We are particularly interested in participating in the process of converting the IPM outputs to the specific generating unit emissions that REMSAD will require.

To further evaluate any mercury air quality modeling under consideration, we would request a summary of the following information:

1. Discussion of the goals for mercury air quality modeling
2. Description of the models' basic features, including version number
3. Description of model setup including:
    a. Geographic domain, and horizontal and vertical resolution
    b. Time resolution of study
    c. Emissions inventory, processors and vintage of data
    d. Atmospheric chemistry mechanisms or solvers
    e. Meteorological processors
4. Mercury deposition results, including total, wet and dry and speciated fractions
5. Statistical comparisons of model performance against observations
6. Description of any existing mercury monitoring databases
7. Comparisons of base case results to other air quality modeling results

8. Results of any sensitivity or policy relevant cases

To support a better understanding of the impact of any MACT policy on mercury deposition patterns, we would like to suggest that two particular modeling scenarios be run initially. The first scenario would include a run that duplicates existing emission data for mercury (1999 ICR or most current available) and compares it to contemporaneous monitoring observations. If performance of the model is found to be acceptable with that run, then another run would be made in which utility mercury emissions would be 'zeroed out' and a comparison of the two cases performed.

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We appreciate EPA's willingness to consider these issues and look forward to a continued productive dialogue with the Agency.