BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R06-25
PROPOSED NEW 35 ILL. ADM. CODE 225	)	(Rulemaking – Air)
CONTROL OF EMISSIONS FROM	)	
LARGE COMBUSTION SOURCES(MERCURY)	)	

NOTICE

TO: Dorothy Gunn
Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601-3218

SEE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that I have today filed with the Office of the Clerk of the Illinois Pollution Control Board the TESTIMONY OF DAVID C. FOERTER, EZRA D. HAUSMAN, Ph.D., ROBERT J. KALEEL, SID NELSON JR., and JEFFREY W. SPRAGUE, and AMENDED TESTIMONY OF CHRISTOPHER ROMAINE, a copy of which is herewith served upon you.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: ______________________
Gina Roccaforte
Assistant Counsel
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DATED: April 28, 2006

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THIS FILING IS SUBMITTED ON RECYCLED PAPER

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TESTIMONY OF DAVID C. FOERTER

My name is David C. Foerter and I am the Executive Director of the Institute of Clean Air Companies (ICAC). I am testifying on behalf of the Illinois Environmental Protection Agency. ICAC is the national trade association of companies that supply air pollution emission control and monitoring technologies for electric power plants and other stationary sources. ICAC represents eighty-five of the leading manufacturers providing emissions control solutions for affected industries as well as employment opportunities across the U.S. ICAC recommends that any program to control mercury emissions be designed with consideration of the following important goals: ensuring substantial environmental improvements, providing flexibility to all affected parties, minimizing costs, maintaining fuel diversity, and continuing reliable electric generation. To that end, ICAC would like to provide the following comments.

Commercially Available Technology

Despite the lack of a strong national mercury requirement for coal-fired utilities, a number of mercury control technology options are commercially available while other options are still in development and testing phases and their deployment can benefit from regulatory certainty. A rapid development of mercury control technologies over the last several years produced a number of technologies available for implementation of mercury control programs for coal-fired power plants. A large number of full-scale demonstrations and even more laboratory tests were conducted and provide a foundation of information on the effectiveness of controls for various coal types and existing emissions control configurations. Much of the improvements in technology are documented in the Illinois technical background document. In general, there are a suite of options available to cost-effectively control mercury emissions from power plants of different configurations and coal types.

Based on recent demonstration results, significant amounts of mercury can be removed through the use of existing controls. Existing control installations such as fabric filters, electrostatic precipitators, SO_2 scrubbers, selective catalytic reduction (SCR), and others are currently achieving high levels of mercury reductions even though these processes were not originally intended, designed, nor optimized for mercury capture. With the implementation of mercury regulatory requirements beyond incidental co-benefit levels of control, a number of options for optimizing existing controls will be implemented to provide cost effective reductions.

Mercury specific control technologies such as sorbent injection systems are commercially available and have been demonstrated at full-scale on various coal-fired boilers, coal types, and control configurations. Multipollutant control approaches as well as other mercury specific technologies provide additional low cost, innovative approaches to mercury control. Advances in control technologies have overturned the assumptions that sub-bituminous coals are the most difficult and expensive to control. For example, a better understanding of sub-bituminous coals has led to successes in dramatically reducing the cost of sorbents while increasing the control effectiveness.

Over the last year, ICAC members reported booking new contracts for equipment for sixteen power plant boilers, with engineering companies reporting new contracts on several facilities to develop design specifications for procurement of mercury specific control technology. These contracts are for controlling mercury on new and existing sources, burning bituminous and subbituminous coal, with different particulate capture equipment such as fabric filters and electrostatic precipitators (ESP). The contracts for commercial systems are attributed to federal and state regulations, including new source permit requirements and consent decrees, which specify very high levels of mercury capture. ICAC strongly believes that the strength of these bookings effectively ends any debate on the commercial availability of mercury specific control technologies.

Providing Flexibility

The Institute advocates setting requirements that effective use available control technologies, and then using flexible approaches to promote innovation and early compliance with those requirements. Flexible approaches should establish an environmental goal that allows affected sources to choose among control options and seek a least cost approach to achieving that goal. Examples of flexible approaches include market-based approaches, capital recovery programs, plant-wide averaging, annual emissions averaging, early reduction incentives, safety valves, or other approaches. Incentives combined with concrete goals can encourage further technology innovation and offer opportunities to focus controls on the most cost effective sources and coal types.

Regulatory programs that allow a larger pool of affected sources to work towards one goal will produce higher emission reductions at lower costs. An averaging program that permits company wide or plant level averaging, or alternatively, a cap-and-trade program, provide the most cost-effective means to achieve substantial mercury emission reductions from the power generation industry. These types of programs compel utilities to target reductions from the units where controls are most cost-effective, and focus in nearly all cases on the larger units with the highest emissions. These flexibilities within a program encourage economically efficient decisions. Typically, a unit with the highest mercury emissions will be among the first to be controlled since the cost per pound of mercury controlled will be the lowest at these units.

Regulations that mandate reductions through the use of a dual limit of an emission rate and a maximum control efficiency would also provide some flexibility to utilities. It also compliments the fundamental capabilities of the control technologies which become increasingly more cost effective and yield higher percentage removals the higher the mercury concentration is going into the plant. The way that this would function for utilities, for units that have a high inlet mercury concentration, it would be more cost effective to achieve a higher maximum control efficiency while units that have lower inlet mercury concentrations may find it more cost effective to meet lower emission rates. Given a longer compliance period, such as a yearly average, utilities will have the opportunity to meet stringent limits as it will provide more ability for utilities to take into account changes in mercury content in coal or other operational changes at the boiler compared to shorter averaging periods.

Encouraging early adoption of control technology will create benefits to both the power generator and the environment. This sort of mechanism has been implemented in other market-based programs such as the US EPA's Acid Rain and NO_x Budget Programs. Under the Acid Rain Program, allowance credits were banked by those plants that installed controls in advance of the compliance date and achieved emission reductions greater than their historical baseline emissions. Under the NO_x Budget Program, a limited pool of allowance credits were distributed to plants that installed controls in advance of the compliance date and reduced their emissions below a specific NO_x emission rate. This method not only encourages plants to install controls early but also gives incentives to maximize the performance of their emissions control strategy. Banking of credits at individual plants (not for sale to other plants but to offset future emissions) will lead to greater mercury reductions earlier and will also significantly reduce costs for the plant.

Maintaining Electric Reliability

Electricity is essential to our modern economy. Advancements in technology have increased U.S. productivity and driven growth, and many technologies have increased electricity demand. Currently, coal generation provides more than fifty percent of the nation's electricity supply with the remainder being provided by nuclear, natural gas, oil, hydro, and other renewables. Certain fuels in the electricity generation mix are better suited than others for particular applications. That's why a variety of fuels – as well as increasingly more cost-effective and efficient ways to use and conserve energy – is needed.

Low-cost, reliable electricity results in part from our ability to utilize a variety of readily available energy resources – coal, nuclear energy, natural gas and hydropower, and other renewable energy resources. Fuel diversity is key to affordable and reliable electricity. A diverse fuel mix also helps to protect consumers from contingencies such as fuel unavailability, price fluctuations and changes in regulatory practices.

Creation of Jobs

The installation of air pollution control equipment on power plants also creates crucial job opportunities for a variety of professions. Many of the jobs in the air pollution control industry are high quality, high-tech jobs, such as engineering and computer aided design positions. In addition to the high tech jobs, the following types of labor are required for the installation of the technologies on coal-fired power plants including: general construction workers for site preparation and storage facility installation; skilled metal workers for specialized hardware assembly; other skilled workers such as electricians, pipe fitters, millwrights, painters, and truck drivers; and other unskilled labor to assist with hauling of materials and cleanup. There are more than 150,000 air pollution control professionals working in the U.S. today that are continually advancing the capabilities of the industry to met environmental requirements.

Conclusion

ICAC acknowledges even in light of rapid success in the development of effective mercury capture technology and the initiation of a commercial market, plant specific engineering and technical challenges may exist as they have for any emission control program. However, the technologies that exist today can be deployed along with regulatory flexibilities to produce a cost effective and sound control program.

The Institute supports the development of regulations that provide cost-effective reductions in mercury emissions through the development of emissions targets that maximize mercury removal while minimizing risk to all stakeholders. In order to protect electric reliability and reduce compliance costs, the implementation of market-based programs and other flexibility mechanisms are recommended. The development of regulations that go beyond the U.S. EPA requirements will further the development of control technologies, spur development of even more cost effective technologies, and will create jobs for the design and construction of emission control equipment.
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TESTIMONY OF EZRA D. HAUSMAN, Ph.D.

Qualifications

My name is Ezra D. Hausman, Ph.D. I am a Senior Associate with Synapse Energy Economics, Inc. ("Synapse"), a research and consulting firm specializing in energy and environmental issues. Synapse's areas of expertise include electricity market analysis; generation, transmission and distribution system reliability; market power analysis; electricity market price forecasting; valuation of stranded costs and benefits; and integration of energy efficiency and renewable energy in wholesale electricity and capacity markets.

I have been employed by Synapse since July of 2005. Prior to this I was employed as a Senior Associate with Tabors Caramanis & Associates (TCA) since 1997, performing a wide range of electricity market and economic analyses and price forecast modeling studies, including asset valuation studies, market transition cost/benefit studies, market power analyses, and litigation support studies. I have extensive personal experience with market simulation software including GE-MAPS, and I have strong familiarity with a number of other market simulation environments and approaches to electricity market, and economic analysis.

I hold a B.A. from Wesleyan University, a M.S. in civil engineering from Tufts University, an S.M. in applied physics from Harvard University and a Ph.D. in atmospheric chemistry from Harvard University.

Purpose and Summary of Testimony

I was asked to testify today by the Illinois Environmental Protection Agency (Illinois EPA) in order to offer my expert analysis of how the proposed Mercury emissions rule in

Illinois will impact the Illinois electricity market and the Illinois economy. Much of my analysis is based upon information contained in the Technical Support Document (TSD) provided by the Illinois EPA in support of the rule. I have also relied upon data provided by ICF Corporation relating to their use of the IPM model to analyze the impacts of this rule. While I do rely upon the same underlying data used by ICF, in many cases, my analysis differs from the conclusions reached by ICF using this model. I will explain these differences, and why I feel my analysis to be more realistic, as appropriate throughout my testimony.

I begin with my analysis of the TSD's conclusions regarding the proposed rule's expected impact on wholesale and retail electricity prices, and on the competitiveness of Illinois generating units. I will address the question of whether existing coal-fired generating plants would be likely to “retire” as a result of the proposed rule, and whether this would cause reliability concerns in the state of Illinois. Finally, I will offer some analysis of the economic impact of the proposed rule on the economy and employment in the State of Illinois, as well as health-related impacts. My conclusions may be summarized as follows:

- The cost of producing electricity at Illinois coal plants is likely to increase by about 0.0375 cents/kwH;
- The impact on retail prices is likely to be much smaller than the impact on production cost because coal units in Illinois only set the price of electricity for a fraction of the hours of any year. I calculate that the *total* price impact of the rule for Illinois ratepayers will be between zero and $11 million per year, in 2006 dollars;
- I calculate that the *total* price impact on consumers in the broader region (Illinois and the surrounding states) will be up to $60 million annually, which is roughly twice the total annual cost of compliance for Illinois generators;
- In terms of reliability impacts due to retirements of plants that would be rendered uneconomic by the rule, I conclude that a very small number of plants are likely to retire, if any, and that the impact on system reliability is negligible;
- In terms of economic impacts, I find that any direct job losses due to the proposed rule are likely to be more than offset by economic benefits, including construction, installation and operational employment increases, and new jobs in the tourism and recreational fishing industries;

- The health and avoided premature death benefits of reducing mercury emissions under the rule will be hundreds of millions of dollars per year, well in excess of the cost of implementing the rule.

Impact of Proposed Rule on wholesale and retail electricity prices

I first address the TSD's analysis and conclusions regarding the proposed rule's expected impact on wholesale and retail electricity prices and on the competitiveness of Illinois generating units, relating especially to the material on that point contained in Chapter 9 of the TSD. This section of my testimony supports the following conclusions:

1. The analysis of electricity markets summarized in Chapter 9 of the TSD overstates the effects of the proposed rule on electricity market prices and costs to Illinois electricity consumers.
2. The retail electricity cost impact for Illinois is likely to fall somewhere between zero and $11 million per year.
3. The effect of the proposed rule on the competitiveness of coal-fired generating units in Illinois is likely to be quite modest, smaller than the effects of other factors.

Electric Power System Modeling

The operation and evolution of electric power systems are complex processes subject to a wide variety of technical, economic, and regulatory factors. Computer models are used to understand these processes, and to estimate the impacts of changes to the system upon the characteristics and costs of the system; one such change would be a proposed environmental regulation such as the proposed mercury rule. When analyzing such a change, it is useful to consider the short-term and the long-term separately, since the roles of various factors and the uncertainty associated with market simulations differ for the two situations.

In the short-term, the set of capacity resources is largely fixed and impact analyses can focus upon the *operation* of the system. System operations are complex but relatively well understood and subject to rules and procedures that are implemented by grid operators such as PJM and MISO[1]. Regional wholesale power markets are dispatched

[1] The PJM Interconnection (“PJM”) and the Midwest Independent Transmission System Operator (“MISO”) are centrally-dispatched Regional Transmission Organizations (RTOs) which control large

based upon bids submitted by generators in order to minimize the total costs, subject to various physical constraints such as transmission limitations and generator ramp rates.

Dispatch models such as MAPS and MARKETSYM simulate the dispatch using very detailed inputs on the available resources, their costs and heat rates, their locations relative to transmission constraints, and chronological electricity demand by customers, typically on an hourly basis. The inputs that matter to operations analysis are mainly "variable costs" which include fuel and some O&M costs including the variable costs of pollution controls. The outcome of these models depends directly upon the input data, so any uncertainty in forecasting future conditions, of which there is a great deal, results in implicit uncertainty in the forecast. Nonetheless, the algorithms are generally accepted to be good for representing the phenomena that they attempt to simulate – the deterministic operation of the electric power system given a certain set of input assumptions.

In the long-term, say five years or more, the set of capacity resources can be changed by capital investment decisions. In this case impact analysis must address the *capacity mix* of the system as it evolves over a period of years, with power plant additions and retirements as well as capital investment in the generating plants, including investments in air emissions controls. Capital investment and plant retirement decisions are quite complex and notoriously difficult to represent in a computer model. In the simplest sense, they depend upon reasonably well understood fundamentals such as discounted cash flow analysis. For example, a unit retirement decision would, at its simplest, be a straightforward matter of projecting forward-going costs (e.g., for fuel, O&M, and required investments for continued operation) and expected revenue (e.g., for selling capacity, energy, and any ancillary services into the market), and applying a discount rate to compute the present value of the net revenues. However, these decisions also depend upon a number of highly complex factors and considerations such as:

- Selection of the discount rate to use in the present value calculation in any particular situation;

regions of the eastern United States electricity market. Illinois is split between these two, with the northern area (including Chicago) controlled by PJM, while the southern part of the state is controlled by MISO.

- Consideration of strategic factors such as market power;
- Consideration of uncertainty, risk, and option value, which are generally not represented in market simulation models;
- Regulatory constraints and risks.

Attempts have been made to incorporate some of these into computer models, but this is quite challenging, and the accuracy of such models will be relatively poor. The results depend upon the input data assumptions as well as algorithms to represent complex corporate investment behavior, which at times can turn on little more than a decision-maker's hunch about the future. The assumptions and algorithms may or may not be realistic in any particular situation.

In this case, the Integrated Planning Model (IPM) was used to estimate the electric market effects that are reported in Chapter 9 of the TSD. The IPM model has previously been applied by the U.S. EPA for environmental policy impact analysis, including analysis of the impact of the Clean Air Mercury Rule on a nationwide basis. The model, developed by ICF Consulting, attempts to represent both system operations and capital investment decisions over a multi-year planning horizon; in tackling both complex problems at once, of necessity it does both in a highly simplified manner.

IPM is a linear programming model that develops a single scenario for system capacity additions and retirements by finding the set of decisions that minimizes the present value total costs to operate the entire electric power system over a specified period, subject to various constraints. For example, demand must be met in each region for each time period, and capacity requirements must be satisfied. Limitations on air emissions must be observed, transmission limits on key interfaces must be respected, and so on. IPM is a deterministic model that works with perfect foresight, by which I mean that it makes its internal choices about operations and investment as if decision-makers knew (or believed) that the modeler's input assumptions about future load conditions and technology costs were guaranteed to be perfectly accurate. It calculates some costs endogenously, such as fuel costs and emissions allowance prices, based on input assumptions about emission caps and well-head and minemouth prices, plus its internally calculated demand for those items. However, both the deterministic inputs and the algorithms used to calculate prices involve some amount of uncertainty that is not publicly estimated by IPM, but which must be assumed to exist by anyone using these results.

In order to accommodate the large geographic scope and the ambitious incorporation of capital investment decisions into the model, IPM used aggregated and simplified data in its unit dispatch function. For example, IPM represents system load conditions using a very limited number of “segments” (i.e., a year of customer loads is represented by six load segments in each of two seasons.) Generating units are not dispatched chronologically as they are in a real market; rather, the generators are dispatched to meet each of these load segments as part of the single, all-encompassing optimization problem, and the resulting unit operation is extrapolated and interpreted to represent annual operations. IPM simulates generating unit forced outages as capacity deratings. That is, rather than simulate actual random outages of generating units during dispatch, the model reduces the capacity of each generating unit to approximate the effect of forced outages. IPM predicts plant additions and retirements such that total present value system cost in the model, over the entire planning period, is minimized, but selects additions only from among a list of potential resource additions with specified cost and operational characteristics. All of these simplifications should be kept in mind when interpreting the results of one or more IPM model runs.

The nature and extent of the simplifying assumptions suggest that the dispatch representation in the model is quite coarse-grained. For capital investment and retirement decisions, the model has some problematic differences with the way that such decisions are actually made; for example, IPM allows fractions of units to be built or retired in order to reach an “optimal” result, and does not take uncertainty about the future into account. The model results show a considerable degree of lumpiness, as is inevitable in a model that represents hourly dispatch in such a highly aggregated fashion. This may not be a problem in some cases where the policy being analyzed in much larger in scope or impact, such as a national CAMR analysis, for which one could argue that the errors tend to cancel each other out. However, when trying to discern impacts on the scale of a single state, this lumpiness can obscure the information one seeks to obtain from the model. In sum, my judgment is that IPM is ill-suited for analysis of a rule in a limited geographic area (e.g., Illinois), affecting a small number of generating units (e.g., the existing coal-fired units in Illinois), with a relatively small compliance cost (e.g., estimated at $33 million per year in Table 8.7 of the TSD). The model results in this case bear out this judgment.

My concern about the coarse resolution of the model is particularly acute in this case because the result of interest is the *difference* between two model runs, one with and one without the Illinois rule. If the inaccuracy in an individual model run is, say, plus or minus 5 percent for the output variable of interest (e.g., the market price in a particular location) that might be perfectly acceptable for some purposes. But for understanding the difference between two such model runs where the policy is a relatively small effect (e.g., less than 1 percent) then it is impossible to get a meaningful result by comparing two individual runs each with 5% uncertainty. The “noise” simply overwhelms the “signal”.

In a national scenario, IPM is simulating a system of more than 10,000 generating units in 48 states, representing a total electricity industry with a total capacity of about 950,000 MW and annual plant expenditures of about $90 *billion*. In contrast, the Illinois rule which it is attempting to analyze, will effect 25 coal-fired generating units and will have a compliance cost of about $33 *million* on an annualized basis. This level of precision is simply far too much to ask from such a coarse-grained and large scale modeling exercise.

Impacts of the Proposed Rule on Costs and Electricity Market Price

The application of the Illinois mercury control rule will reduce the mercury emissions from Illinois coal plants, but will also add to the costs of those plants and to the variable cost of their generated electricity. A detailed analysis of the mercury control costs on a unit by unit basis is contained in Chapter 8 of the TSD. The analysis supporting these findings was carried out by Dr. James Staudt of Andover Technology Partners. The starting point for our cost impact analysis is summarized in Table 8.7 of that report and presented below, in a slightly different format.

Mercury Control Costs for Illinois Coal Plants

In thousands of 2006 $

	CAMR 2010	Illinois Rule	Difference
Capital Investment	$35,515	$75,593	$40,078
Annual costs:			
Sorbent Cost	$18,665	$41,729	$23,064
Toxecon O&M	$0	$425	$425
Ash Disposal	$9,900	$13,403	$3,503
Annualized Capital Cost*	$4,972	$10,583	$5,611
Total Annual Cost	$33,537	$66,140	$32,603

*Assumes 14% capital recovery factor

The yearly additional control costs associated with the Illinois rule are $33 million, of which most of the cost is for sorbent. This is the cost borne by the generating unit owners to retrofit and operate their units with mercury emissions controls; it does not translate directly into electricity prices and costs to consumers.

The historic generation from the Illinois coal plants, from TSD Chapter 8, is 86,997 GWh. That converts into an average cost increase for the Illinois coal plants of $0.375/MWh. For comparison, current retail prices in Illinois are about $70.00/MWh and are likely to increase if price caps are removed as proposed.

In order to determine how this increase in coal plant costs will affect electricity market prices, it is necessary to estimate the amount of time that the coal units bearing these extra costs are “on the margin” and therefore influencing the market price for electricity in the regional dispatch. That, in turn, depends upon regional operation of the electricity grid and the dynamics of new entry to the electricity market. I believe that a reasonable range for the annual electricity wholesale market cost to Illinois customers is between zero and $11 million.

I calculate the upper end of this range as follows.

1. I estimate that coal generation is "on the margin" in the regional dispatch 85% of the time.[2]

2. The Illinois electricity market is a tightly interconnected part of a much broader wholesale electricity market. For current purposes I will conservatively assume that this market includes Illinois, Indiana, Wisconsin, Iowa, Missouri, and Michigan, of which Illinois contains about 20% of the regional coal generation.[3]

3. I multiply the $0.375/MWh cost increase from the rule for Illinois coal by 0.85 and 0.20 to reflect the contribution of Illinois coal units to the regional electricity market price, yielding a wholesale electricity market price impact of $0.064/MWh.

4. At annual electricity sales of about 166,000 GWh,[4] the wholesale cost impact to Illinois electricity customers amounts to $11 million. I assume that this increase is passed directly through to the retail cost impact.

I believe this is a conservatively high estimate of the price impact of the rule on Illinois electricity consumers, for the following reasons.

First, my calculations include the variable costs (sorbent and ash disposal) and fixed costs (annualized investment) of compliance with the rule. A dispatch model simulation would only apply the increased variable costs to calculate the energy price effects, since the fixed costs would generally not be included in the generators' energy supply offers.

Second, the compliance scenario introduced in the TSD is a very simple one, and there may be ways that the market could respond to the rule that would achieve compliance at a lower cost. These might include increasing electricity imports (or decreasing electricity exports), retiring inefficient generators, and installing other emission control technologies (e.g., FGD and SCR, where Hg reductions would be a co-benefit). To the extent that

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[2] Based upon the PJM Market Monitoring Unit's "2005 State of the Market Report," March 8, 2006 (which indicates on page 86 that coal was on the margin 62% of the time in PJM in 2005); MISO's "March Monthly Report: April 20, 2006" (which indicates on page 77 that coal was on the margin about 86% of the time in MISO in that month); and inspection of the capacity supply curve compared with load levels.

[3] A broader region would probably be more appropriate for wholesale market price calculations, given the strong transmission interconnections in the MAIN and ECAR reliability regions. Ideally, multi-area electricity market simulation model analysis would be used to determine the impact of an electricity market price increase upon the regional market, and the extent to which the price increases occur in different portions of the Eastern Interconnection. However, given the lack of transmission constraints inhibiting the *import* of electricity to Illinois, we believe that the six-state region is a reasonably conservative proxy.

[4] According to EIA data, retail electricity sales in Illinois were 139,254 GWh in 2004 and 144,554 GWh in 2005. Extrapolating this growth rate (3.8% annual) to 2009 yields 166,000 GWh.

some of these approaches were found to be lower cost and to contribute to a mixed compliance approach, the overall total cost would tend to be reduced. There is no indication that Dr. Staudt attempted to find the *least cost* compliance scenario, nor was it his task to do so.

Third, and most importantly, is the impact of new market entry in response to anticipated electricity market price increases. In regional electricity markets, the long-term price of electricity is generally expected to be equal to the levelized annual cost of building and operating a new power plant. While there will be excursions above and below this "equilibrium price" set by market entry, there are strong forces working to bring prices into line. If market prices fall below the cost of entry, then developers will defer and cancel generating facility construction projects. If market prices exceed the cost of entry for a prolonged period, then developers will initiate and accelerate capacity construction projects, in order to earn the high profits available under such conditions.

This dynamic of market entry disciplining price increases that would otherwise occur is one reason that I put the low end of potential market price effect at zero. The other reason is that, with excess generating capacity in the region and no relevant and binding limits on power imports (or decreased exports), it may be that existing generators simply cannot increase market prices in order to pass along compliance costs to customers.

The modest impact of the proposed rule on electricity prices can also be seen in the "supply curves" provided here as Exhibits EDH-1 and EDH-2. These were derived from the IPM model files provided by ICF. The graph in Exhibit EDH-1 shows the cost of electricity from Illinois generators only, with and without the proposed rule. The line for the case with the rule shows a slight cost increase relative to the case without the rule, in the middle range of the supply curve—this represents the increased production cost for specific coal units under the proposed rule relative to CAMR. At some load levels, the cost of electricity is actually *lower* with the proposed rule in place, according to the IPM model results. This would occur if certain plants opted to invest in emission control technology as a result of the rule and thereby eliminated the need to purchase allowances for NO_x and SO_2 emissions. The associated capital investment is not a variable cost of production, so it is not reflected in the figure. The graph in Exhibit EDH-2 is an analogous supply curve but for the multi-state region, including Illinois, Indiana, Wisconsin, Iowa, Missouri, and Michigan. Here the effect of the Illinois rule is considerably more subtle, reflecting the fact that the marginal cost of electricity at just about any regional load level would be largely unaffected by the rule. If the curve in Exhibit EDH-2 represents the highly competitive generation mix that serves a large interconnected market including Illinois, then the only time prices can be affected by this rule is when the load falls in the area where these two curves diverge. Even in those cases, the price impact of the rule can be no more than the vertical distance between the lines in that region.

There are large differences in production cost between coal units and the lower-operating-cost nuclear units, and also between coal units and the high-operating-cost oil and gas units. There are, in fact, some substantial differences in production cost among the coal-fired units, which inhabit the range between about $16/MWh and $23/MWh in production cost as shown on the vertical axis. These differences among the coal units have to do with variations in age, size, efficiency, fuel supply and other factors. The cost implications of compliance with the Illinois rule, 37.5 cents per MWh, are quite small in the overall context of variation among generating unit costs of production, and thus the effect on the supply curve for energy is, as shown in the Exhibits, quite small.

Impacts of the Proposed Rule on Generators

The cost impacts are of importance from the perspective of Illinois electricity customers, and they will be of use in estimating the direct impact on the Illinois economy later in this testimony. For generators, the range of impacts differs, but the likely impacts are also quite modest on a net basis.

Consider first the scenario in which market prices are not increased as a result of the rule. In that case, Illinois generators would bear the full compliance cost impact of $33 million per year. While not a trival sum, in the context of the overall electricity markets it is almost negligible. To put it in context, the total cost of fuel to electric power plants located in Illinois amounts to about $2 billion per year.[5]

It is also interesting to consider a scenario in which electricity market prices do increase as a result of the proposed rule. I have proposed a high case in which regional market prices increase by $0.064/MWh. In this case, the total annual cost increase to customers in the multi-state region amounts to about $60 million annually. This is roughly twice the estimated annual compliance cost of $33 million, indicating that generators as a group will be better off financially with the rule than without it. Of course, in this scenario there are winners and losers within the group of generating companies, but on average the generation owners would be more than made whole.

IPM Results

The IPM model was discussed earlier in my testimony, where I highlighted how the coarse resolution of the model limit its utility for simulating a market effect as subtle as the one under consideration here. As may be seen in Chapter 9 of the TSD, the electricity price and cost results obtained using the IPM model are dramatically higher than those I have calculated. Specifically, ICF reported incremental price increases associated with the Illinois rule, relative to the CAIR/CAMR case, of $0.57/MWh, $1.67/MWh, and $1.15/MWh for the years 2009, 2015, and 2018, respectively.[6]

In terms of costs to Illinois electricity consumers, the same IPM runs put the totals for 2009, 2015, and 2018 at $99 million, $311 million, and $221 million.[7] For costs to

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[5] Source: IPM model reports.

[6] The prices reported in Exhibit A.3 on page 4 of "Analysis of the Proposed Illinois Mercury Rule, Appendix A: Summary Results Tables," March 10, 2006, by ICF, are $0.50/MWh, $1.46/MWh, and $1.00/MWh for the three years. But these are reported in 1999 dollars. The "Price Indexes for the Gross Domestic Product" reported by the US Department of Commerce, Bureau of Economic Analysis, indicate an inflator of 14.6 percent from 1999 to 2005. I applied the 14.6 percent inflation factor to convert the prices from 1999 dollars to 2005 dollars.

[7] The costs reported in Exhibit A.5 on page 6 of "Analysis of the Proposed Illinois Mercury Rule, Appendix A: Summary Results Tables," March 10, 2006, by ICF, are separately by customer class. I totaled the customer classes, and got $86 million, $271 million, and $193 million. But because these are in 1999 dollars I applied the 14.6 percent inflation factor to convert the costs from 1999 dollars to 2005 dollars.

"national" electricity consumers, the IPM runs put the totals for 2009, 2015,and 2018 at $332 million, $529 million, and $786 million.[8]

The IPM results imply that $33 million in annual production cost increases would translate into hundreds of millions of dollars of annual costs to consumers. Electricity markets may have their flaws, but the idea that they could be so inefficient and so punitive to customers, and that we reside on a precipice where a small increase in the cost of coal generation will tip us into the abyss, defies credulity. The implication of these results suggests a tremendous windfall to generators flowing from the Illinois rule. My judgment is that that this windfall will not occur, but rather that the impacted coal generators in Illinois may or may not recover the costs of compliance, that the net impact on these entities will be small.

There are various aspects of the way the Illinois rule is modeled in the IPM model that make the IPM impact results conservatively high, including the representation of the emission caps (maximum total emissions instead of maximum emission rates), decreased flexibility in compliance (relative to the Proposed Rule's actual provisions), and the accelerated compliance date (at the beginning of 2009 rather than at mid-year 2009). I review some of these in greater detail in the next section of my testimony. But while these aspects of the IPM modeling approach will tend to exaggerate the impact of the rule, it remains difficult to see how they could account for ICF's results in terms of market prices and customer costs. I can only conclude that the results are an artifact of the model structure, which is designed more for wide-ranging analysis of national policy than for highlighting the smaller-scale impacts of a regional rule.

One effect predicted by the IPM model with which I do concur is that energy exports from Illinois may be decreased as a result of this rule. Units with production costs just below the marginal cost of electricity in the absence of sorbent costs, for example, may be rendered uneconomic to run during certain hours given this small additional expense.

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[8] As with the Illinois costs to consumers, I totaled the customer classes (yielding $290 million, $462 million, and $686 million for the 3 years, respectively) and applied 14.6 inflation factor to convert to 2005 dollars.

However, in this case the revenue they would have earned during these hours would have just barely covered their running costs, so the impact of this output reduction on their overall economic performance will be minimal. Further, if other states adopt similar rules in the future, this effect will be abated.

Finally, I find that IPM is unrealistic in its treatment of power plant retirement decisions. This issue is discussed in the next section.

Electric System Reliability Impacts of the Proposed Rule

The IPM model runs performed in support of the Illinois rulemaking predict the retirement of a number of older, coal-fired generating units as a result of the proposed rule. My judgment is that this prediction is overstated, and that in any case that this level of potential retirements raises no reliability concerns. My reasons are as follows:

- The total MW capacity of retirements predicted by the IPM model runs as a result of this rule is quite modest, representing less than 1% of in-state capacity and a much smaller share of regional capacity. Even this is likely to be an overestimate, given differences between the model implementation and the realities of the marketplace;
- Illinois is strongly interconnected and shares capacity requirements with a large region that will be unaffected by this rule[9], making the total MW capacity of possible retirements comparatively even less significant;
- The reliability regions and market operators encompassing Illinois have rules in place to prevent retirements if the specified units are required for reliability reasons;
- If there are any subregions within Illinois that have capacity shortages, these subregions are likely to have higher electricity prices, meaning that units located in these areas will receive extra revenues and are less likely to retire;
- The units identified for retirement by the IPM model are small and relatively inefficient, and may well be nearing the end of their operating lives in any case; it is likely that they would be retired, upgraded or replaced with more efficient and cleaner technology with or without the proposed rule within the next several years;

[9] A number of other states in the region are considering similar state-specific mercury rules , but the current analysis is focused upon the effect of Illinois' proposed.

- The cost of new entry is only lightly impacted by the rule, so the rule will hasten, if anything, the development of new generating capacity in Illinois and the surrounding region.

Retirements likely to be minimal

The IPM forecast predicts 345 MW of coal plant retirements in Illinois by 2009 in the case including national CAIR/CAMR rule, and an additional 252 MW of coal plant retirements in Illinois by 2009 under the proposed, more stringent Illinois EPA mercury rule. For perspective, the model represents a total of 16,000 MW coal-fired capacity in Illinois and 43,000 MW of total in-state generating capacity. Thus the retirements represent 1.6% of in-state coal generation capacity and 0.6% of total in-state generating capacity.

I believe the IPM model over-predicts retirement in this case, and that the actual number is likely to be far smaller. There are a few reasons for this. One reason is that it is much easier to build and retire generating units in a model than it is in the real world. For example, the IPM model can and does predict "partial" retirements, which is to say that it finds an optimal number of units to retire which may include part of some unit even if that is physically impossible. My understanding is that the IPM model does not have the ability to "mothball" a unit (maintain it in a standby mode) instead of retiring it, which would otherwise allow it to be returned to service much more easily in the future should conditions render that profitable. Mothballing of generating units is quite common in real electricity markets. This is because the option of returning a unit to service in the future, should market conditions become favorable, is valued in a way that is difficult to capture in electricity market models with "perfect foresight".

Another reason that the model overstates likely retirement is that the gas prices calculated by the model are very low compared to today's gas and gas futures prices. Gas prices are calculated endogenously in the IPM model, presumably based on a formula that has been fit to historical gas price trends. Unfortunately, the current gas market prices are well above the historical norm for reasons that reflect the unprecedented growth in demand, increasingly costly domestic gas production, and the globalization of the gas market. ICF provided the gas prices to Synapse upon request, and they come out at about $4.25 per

MMBtu in 1999 dollars. This is perhaps half the cost of gas in today's market or less. As a result, the IPM model would seriously understate electricity prices and revenues coal units would receive when gas is on the margin. If more realistic gas prices were considered in the model, the economics of coal units would look quite a bit more attractive.

Finally, the implementation of the Illinois rule in the IPM model is unrealistically stringent. The rule as proposed allows some flexibility in meeting the requirement, including some averaging of emissions among plants under certain conditions. In the model implementation a hard cap is in place for each plant. Clearly, generation owners who are able to reallocate their emissions among plants will find more economical ways of controlling emissions than they would were they required to rigidly reduce emissions equally on all plants. Specifically, it would often make sense to leave uncontrolled those units that run infrequently, taking advantage of the ability to average overall emissions instead of investing in emissions controls that would be underutilized. While it is hard to draw solid conclusions on capacity factor due to the low resolution of the IPM model, the units that are slated for retirement are those with the lowest reported non-zero capacity factors of all coal units in Illinois. These units would be particularly subject to this particular distortion.

Thus I conclude that the 252 MW of coal retirements predicted by the IPM model are unlikely to occur, but even if they did the implications for reliability would be negligible.

Despite this judgment on my part, it is important to consider the implications in case this level of retirement did occur. I do not believe that this would present a problem in terms of reliability, because both the local and regional systems have considerable reserve capacity. The most recent projection of reserve capacity in the MAIN region,[10] for example, indicates that for the coming summer MAIN has a planning reserve of 17.6% without including "uncommitted resources". When uncommitted resources are

[10] The MAIN region has been superseded as of January 1, 2006, so that Illinois is now divided between the Reliability First and SERC reliability regions. However, the most recent market reports concerning capacity margins were issued under the previous configuration, under which all of Illinois was in the MAIN region.

considered, the planning reserve increases to 21.4%. This compares favorably to the recommended long-term planning reserve margin of 16 to 19% based on the most recent NERC Long-term Reliability Assessment. The same report lists projections of planning reserve margin for the summer of 2010 at 14.8%, without including uncommitted resources. With the uncommitted resources included the planning reserve, the 2010 margin rises to 20.5%. Since MAIN is a summer-peaking region, the winter reserve margins are much higher.

The surrounding regions also report planning reserves ranging from 14.5 to 14.9%, of the same magnitude as MAIN's 14.8% projection, and as these areas have aggregated into larger regions the reserve requirements have decreased (see discussion below). Thus, I conclude that even if 252 MW of Illinois coal generation were to retire, this would not present a reliability problem from a regional capacity perspective.

Sharing of reserves

Any impact of retirements on the ability of Illinois entities to meet their capacity requirement is further diminished by at least three regional initiatives, each of which will increase the effectiveness of resources from the large regional area surrounding Illinois to support system adequacy. First, the former ECAR, MAIN and MAAC reliability regions have been reformed into a single large region reliability organization known as Reliability First, meaning that Illinois (which was in MAIN) now has a much broader capacity pool from which to draw. The MRO region[11], to the north and west of Illinois, is considering consolidation into this larger region. This kind of consolidation generally results in greater levels of reserve sharing and thus boosts reliability throughout the system. Essentially, the diversity of use of resources – i.e., varying times at which systems experience their peak loads – allows for a more efficient sharing of resources across the broader area. This is evidenced by the way in which capacity reserve obligations in PJM have been steadily lowered (on a percentage basis) as the PJM RTO region expanded to include additional utility areas such as American Electric Power,

[11] Formerly known as MAPP

Commonwealth Edison, and Dominion Power--PJM reserve obligations have been reduced from 19% in 1998 to 15.0 in 2005.

Second, the Midwest ISO region is currently planning to coordinate an explicit operating reserve market. This will allow for more efficient use of capacity to support adequacy needs.

Third, the Midwest ISO and the PJM RTO continue to discuss way in which to coordinate their respective market operations, and they have signed agreements with the SPP RTO to further coordinate operations. Such coordination can increase the ability of capacity resources in one region to serve needs in adjacent regions, especially given the diversity in peak load use across such large regions.

Because of all of these trends towards greater cooperation in reserves sharing, and because Illinois is almost invariably is an exporter of power so there are no import constraints, we do not believe that reliability will be threatened by lack of access to adequate reserves with or without the proposed mercury rule.

Rules governing retirements

If, despite all of these factors, a generating unit which is needed for reliability reasons were to be nominated for retirement, either PJM or the Midwest ISO (MISO) can take steps to keep the unit operating, depending on the location of the unit. Indeed, RTOs have done so from time to time. Generally, this involves entering into an agreement with the unit's owner to ensure that the costs of continuing to operate a unit will be recovered, even if the RTO must supplement market or regulated payments for operation with additional compensation.

Thus I conclude that if units are rendered uneconomic by the proposed Illinois mercury rule, but are needed for reliability reasons, either the MISO or PJM market operator has the necessary authority and the procedures in place to either compel or adequately compensate the generation owner to keep the unit on line until an alternative solution can be found.

Retirements unlikely to occur in load pockets due to price signals

The IPM model runs which form the basis for the analysis in the TSD do not represent transmission constraints within, for example, the MANO area which contains Illinois. Thus it may be that there are certain subregions which, for reasons of local transmission or distribution constraints, are particularly vulnerable to reliability problems should generating units in these areas retire. If this were the case, perhaps retirements of small, aging coal plants in these areas would raise some reliability concerns.

However, I do not believe that these concerns would be justified for two reasons. The first is outlined above, which is that the RTOs have the tools and structure in place to prevent retirements of units that are needed for reliability reasons. Secondly, both RTOs operate under a locational electricity pricing system known as LMP, which is designed to produce higher electricity prices in regions that are more expensive to serve. If this is not enough, PJM is moving towards implementation of a locational capacity compensation scheme in PJM, under which generation owners will be paid for their capacity (in addition to their energy) in a way that is designed to compensate generators in capacity-short regions sufficiently to deter retirements and encourage new entry. Thus, I once again conclude that if any specific units are needed for reliability reasons—in this case to ensure local reliability—it would be compensated at a greater rate than would be predicted by the IPM model, and would be unlikely to retire.

Predicted retirements are not unusual

The specific generating units which are predicted by the IPM model to retire as a result of the Illinois mercury rule are Hutsonville Units 5 and 6 (partial) and Meredosia Units 1 through 4. As noted in the TSD, these units are all at least 50 years old and may well be nearing the end of their operating life. Based on data from the IPM model, these units are about 10% less efficient than average for coal-fired power plants in Illinois, and considerably less efficient than newer units. It would not be surprising, especially under conditions of surplus such as those seen in the Illinois region today, to find that such plants are no longer economically justified with or without the proposed rule, especially if there is not some specific reliability-based need for these particular assets. In some cases, units such as these would be replaced with more efficient new plants such as natural gas combined cycle units, or with gas-fired peaking units, at the same location.[12] Such units would offer greater operational flexibility and much lower emissions. Thus, while it is possible that the owners of certain inefficient coal units would find it preferable to take the units out of service rather than to bring them into compliance with new emissions rules, my judgment is that this would not be out of line with the normal evolution of generating assets, may in fact make way for the construction of newer, more efficient units, and in any case would not pose a reliability problem for the state or the region.

New entry unaffected by proposed rule

The final point I would like to make with regard to the reliability impact of the proposed rule is that new generating units are unlikely to be significantly affected by this rule, because they are already required to meet stringent emissions criteria. To the contrary, this rule may give a slight economic boost to new entry if it does, indeed, cause a small number of retirements to be accelerated, or raise local electricity prices by a small amount. Along with this comes greater efficiency, greater operational flexibility, greater unit reliability, and lower emissions. If anything, this would provide a net benefit in terms of electric system reliability in Illinois and the surrounding region.

Conclusions

Based on my analysis of the IPM model data and results, and based on my understanding of market conditions in the MISO and PJM regions, I conclude that the proposed rule will have little if any effect on electric system reliability in the region. I conclude that the number of generating unit retirements caused or accelerated as a result of the rule is very small if any, that there is more than adequate capacity in the region to accommodate any retirements that may occur, and that there are safeguards in place to make sure that retirements will not occur if they would raise reliability concerns.

[12] For example, all units over 50 MW retired between 1999 and 2004 identified EIA Form 860 filing database were replaced with new units mostly gas combine cycle units.

Impacts on the Economy and Employment in Illinois

I have not performed a specific economic modeling study on the impacts of the proposed mercury rule on the economy of the State of Illinois. I do not believe that such a study would be particularly informative as to the impacts attributable to changes in generation costs or prices. As I explained above, the direct impact of the rule in terms of electricity prices and costs to consumers will be quite modest. However, based on a range of existing studies and on closely related modeling analysis performed by Synapse staff in similar cases, I am able to estimate certain of the effects of this rule on the Illinois economy. Many of these direct and indirect economic costs and benefits to the state of Illinois are also modest in scale relative to their uncertainty. As will be explained below, the situation with regard to economic value of the public health benefits of the Proposed Rule is quite another story.

Retail Rate Impact

My estimate of the incremental total retail cost impact from the proposed rule is between zero to $11 million per year in 2006 dollars, over and above the cost impact of the CAIR/CAMR requirements. For perspective, this range represents approximately 0% to 0.1% of the Illinois retail electric bill of $9,359 million per year.[13]

In an earlier study performed for the Citizens Utility Board of Illinois, Synapse estimated the effect on employment in Illinois associated with changes in the total cost of electricity. On the basis of that relationship, this Proposed Rule’s estimated incremental retail cost impact would result in the loss of between zero and about 69 jobs in the state of Illinois. I would caution that even the upper end of this range is quite small relative to the precision of macroeconomic models, and relative to what I assume to be the day-to-day variation in employment in the state. Thus I would conclude that the magnitude of this effect may be statistically indistinguishable from zero impact on employment.

[13] Total retail electric costs in 2003 according to the US EIA: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

Impact of Potential Generating Unit Retirements

The IPM model results reported in the TSD predict that the Proposed Rule may lead to retirement of certain coal plants now operating in Illinois, over and above the potential impact of the CAIR/CAMR requirements, totaling 243 MW or about 0.6% of in-state generating capacity. This includes one "partial retirement" which is wholly an artifact of the model structure. The employment at these units is estimated to total 160 jobs.[14] In addition, these plants purchase goods and services from the economy to operate. If there were a net loss of generating capacity in Illinois, the loss of jobs would exceed the direct decrease in generating plant employment by some factor.

As discussed above, however, my judgment is that the unit retirements are probably overestimated due to limitations of the model, and in any case the prediction that these small, aging, and inefficient coal plants will retire during the next decade is not out of line with normal evolution of the generation stock. Furthermore, were these retirements to occur, it is likely that the retired capacity would be replaced by newer, more efficient plants, quite possibly even in the same location, providing employment benefits associated with plant construction for up to several years. Thus I judge the direct impact in terms of employment at Illinois generating units to be small, if any.

Other employment impacts in Illinois

In addition to the direct impact flowing from employment at generating units, there are a number of beneficial impacts on employment in Illinois that may be expected from the Proposed Rule. These include:

1. Employment gains due to installation and operation of mercury controls.

   Compliance with the Proposed Rule will require certain capital investments in the early years of the Proposed Rule and certain ongoing operating and maintenance costs, the largest of which is likely to be purchase of sorbent. The TSD provides an estimate of the capital cost of incremental Hg controls. Table 8.7 of the TSD estimates this cost at $35.5 million over the CAMR cost of $75.6 million in 2006

[14] TSD at 201

dollars. The Proposed Rule provides considerable flexibility in implementation timing and details, and as a result it is likely that the employment benefit of the capital investment portion of compliance costs, as well as any multiplier effect through the state economy, will be spread over several years.

There are also likely to be annual O&M costs for mercury controls; estimates of these are provided in Table 8.7. These costs include:

- Sorbent cost $23.064 million per year
- Toxecon O&M cost $0.435 million per year
- Ash disposal cost $3.503 million per year

I cannot predict what fraction of this annual expenditure will be for Illinois goods and services, but there will clearly be some local benefit.

2. Impact of Increased Demand for Illinois Coal

The IPM model predicts that there will be an increase in generation from Illinois coal under the Proposed Rule compared to the CAIR/CAMR scenario. The increase varies with the scenario year, ranging from 40 TBtu to 67 TBtu, assuming that all bituminous coal burned in Illinois coal-burning EGUs comes from Illinois.[15] On the other hand, the analysis in Chapter 8 of the TSD suggests that all existing Illinois coal-burning EGUs can meet the Proposed Rule's requirements without changing the type of coal they burn. For purposes of this analysis, I assume a range of incremental use of Illinois coal of zero to 50 TBtu.

The US average as received heat content of bituminous coal is 24 MMBtu/ton.[16] A range of incremental consumption of Illinois coal from zero to 50 TBtu then corresponds to an increase in consumption of Illinois bituminous coal of zero to 2.08 million tons. The 2004 production of bituminous coal in Illinois was 31.5 million tons, which was 79% of total coal production in Illinois that year.[17] This is a

[15] TSD Table 9.10; TSD at 201.
[16] US EIA online glossary, at http://www.eia.doe.gov/glossary/glossary_b.htm.
[17] US EIA Annual Coal Report 2004.

percentage increase of zero to 6.6%. Average direct employment in coal mining in Illinois for 2004 was 3573 jobs.[18] If we assume that 79%, or 2823 jobs, were in bituminous coal mines, a 6.6% increase in production of Illinois bituminous coal production would result in an approximate increase in employment of 186 direct jobs, along with a substantial number of additional jobs in secondary employment.

3. Impact of Enhanced Sport Fishing and Other Wildlife Activities

According to the TSD, "Any improvement, or prevention of loss, to Illinois' fish and wildlife activities through implementation of Illinois' mercury rule could have a positive impact to this important industry."[19] I agree. The relevant wildlife-associated recreation activities include at least sport fishing said to be worth "more than $1.6 billion to the State economy when considering the salaries from jobs created, as well as sales and motor fuel taxes, and State and federal income taxes."[20] However, this includes all such activities in the state, including those on the Great Lakes. Preparing a specific estimate of the likely impact of the Proposed Rule on these expenditures is beyond the scope of this study. However, for illustrative purposes, consider the scenario where the Proposed Rule results in an incremental 1% increase in sport fishing. This would produce an additional stimulus to the state economy of about $16 million per year, and to an incremental increase in employment of about 130 jobs.

4. Impact of Health Benefits

The most significant economic impact to be anticipated from the proposed rule flows from the long-term health and avoided premature mortality benefits of reducing the environmental loading of mercury. Chapter 3 of the TSD reviews several studies of the direct economic cost of mercury exposure, whether due to power plant emissions or other sources. There is wide variation in these estimates, and they were not necessarily specific to Illinois or the Proposed Rule. However, they may be taken as indicative of the hidden costs of mercury emissions associated with human health,

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[18] EIA *Annual Coal Report*, 2004.
[19] TSD at 189.
[20] TSD at 189.

lost IQ points and premature mortality impacts that will be partially abated by the proposed rule.

To estimate the economic value of this benefit, I rely on the results of the very recent NESCAUM/Harvard study[21] cited in the TSD. This study concludes that the *annual* economic benefit of avoided health and mortality impacts is about $182 to $194.5 million per ton of mercury removed.[22] The TSD (p. 29) indicates that the incremental mercury removal due to the proposed rule is approximately 2400 pounds per year relative to the CAMR limit for the first ten years of implementation; the benefits of each ton of avoided mercury emissions will continue to accrue year after year. This leads to a health and avoided mortality benefit from the Proposed Rule which may be valued well into the billions of dollars over 10 years. Estimating the considerable secondary effects of this reduction in adverse health impacts, avoided intellectual impairment and improved productivity is beyond the scope of this study.

In summary, I find that the direct economic losses associated with implementation of the proposed rule to be between zero and 69 jobs due to the retail rate impact of between zero and $11 million, and a maximum of 160 jobs associated with unit retirements should they occur as projected by the IPM model. On the other hand, I find that there are likely to be employment benefits associated with installation, operation and maintenance of mercury control technologies, construction and operation of replacement generation technology, and possibly with the increased use of Illinois bituminous coal. I find that employment benefits associated with increased fishing and tourism due to decreased mercury loading in the Illinois environment and waterways will be on the order of 130 jobs for each 1% increase in recreational fishing. My judgment is that the increase in employment associated with these benefits is likely to more than offset the potential decreases. Additional employment benefits associated with installation and maintenance of mercury controls, and short- and long-term employment associated with construction and

[21] NESCAUM, 2005. *Economic Valuation of Human Health Benefits of Controlling Mercury Emissions from U.S. Coal-Fired Power Plants.* http://www.nescaum.org/documents/rpt050315mercuryhealth.pdf/
[22] Ibid. p. 193.

operation of new power plants, would be likely to put employment gains associated with this rule well in excess of employment losses.

Finally, I conclude that there will be significant long-term economic benefits associated with reduced health care costs, improved productivity and avoided premature mortality due to the proposed rule. These combined benefits would be worth several billion dollars over the first ten years, alone exceeding by over an order of magnitude the implementation cost of the plan during that period. Thus, I expect the Proposed Rule to have a significantly positive and long lasting effect on the economy of the State of Illinois.

Overall Conclusions

My overall conclusions may be summarized as follows:

- The proposed rule will have at most a modest impact on the cost of electricity to consumers, reflecting the relatively modest cost of compliance for Illinois generating companies;
- The proposed rule will not raise system reliability concerns because its overall effect on plant retirements will be small;
- While there may be some negative direct economic and employment-related impacts of the rule flowing from the increased price of electricity and the loss of jobs if power plants do close down, these effects are small and will be overwhelmed by the positive economic impacts of the rule. These positive impacts include (but are not limited to) direct employment benefits, benefits in tourism and recreational fishing, and the substantial economic value of improvements in human health and avoided premature mortality.

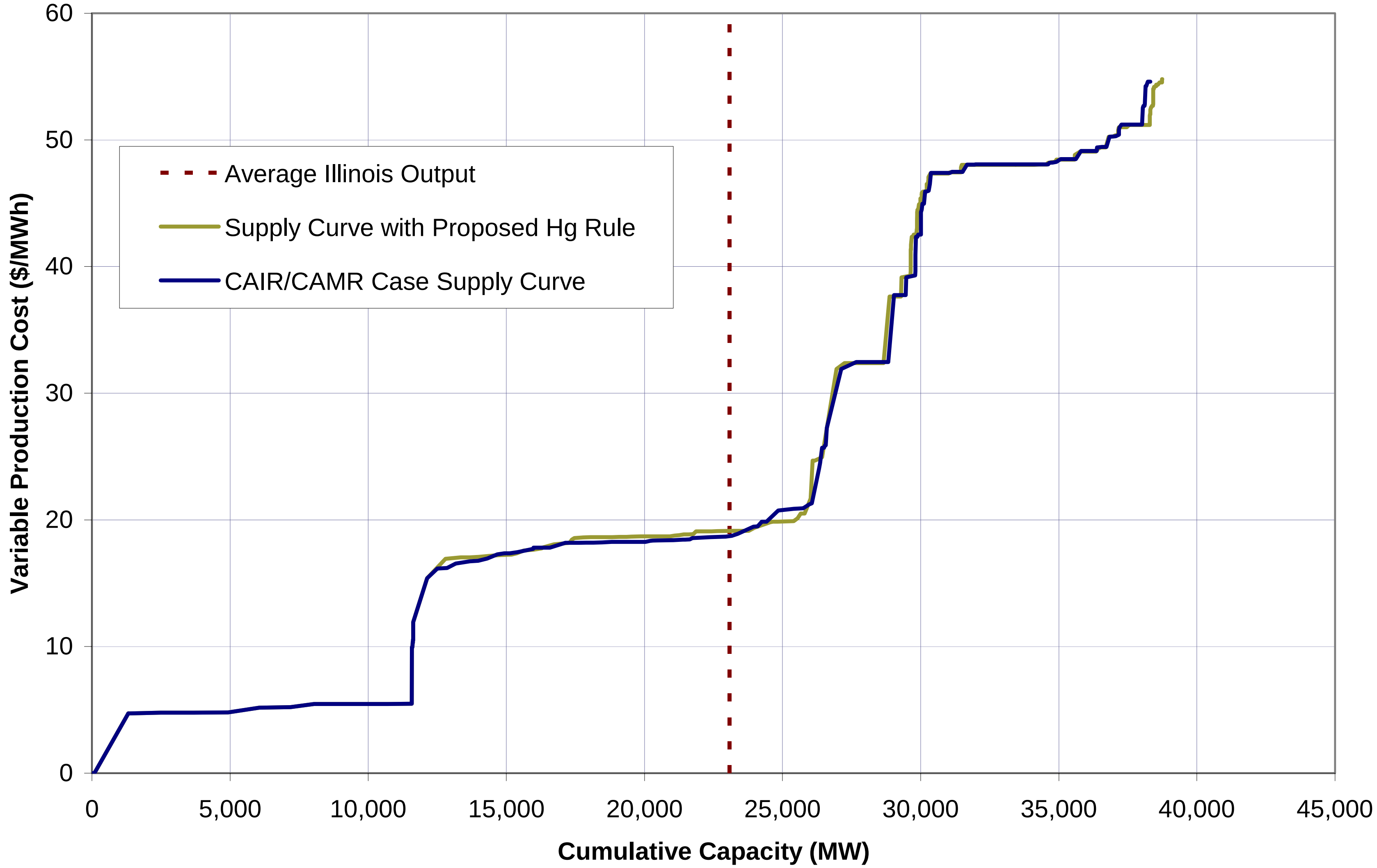

Exhibit EDH-1. Variable cost supply curve for Illinois generating units under the proposed mercury rule, compared with the supply curve under CAIR/CAMR only case. Based on IPM model data and results.

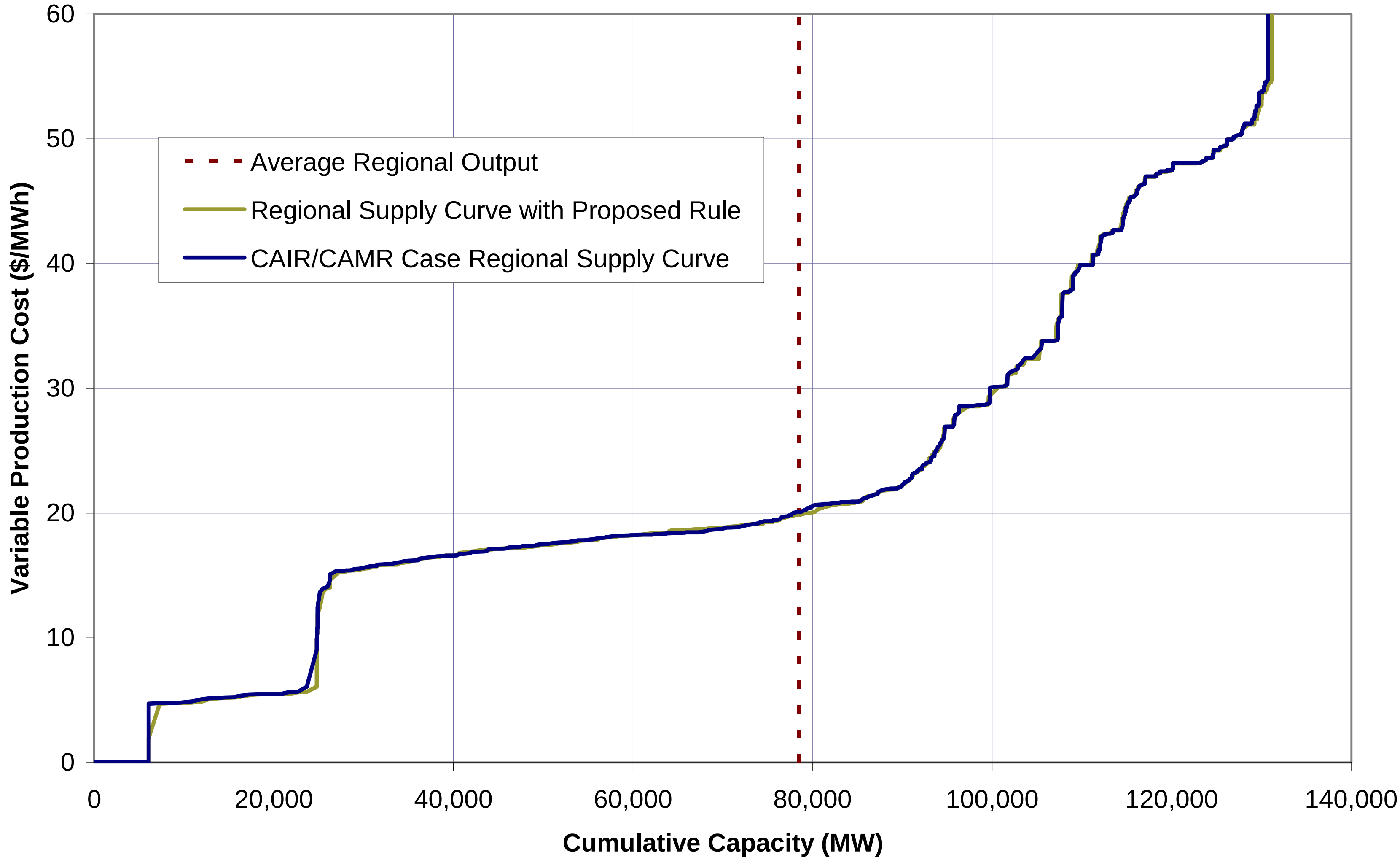

Exhibit EDH-2. Comparison of variable cost supply curves for combined generating stock in six-state region, including Illinois, Indiana, Wisconsin, Iowa, Missouri, and Michigan. Based on IPM model data and results.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R06-25
PROPOSED NEW 35 ILL. ADM. CODE 225	)	(Rulemaking – Air)
CONTROL OF EMISSIONS FROM	)	
LARGE COMBUSTION SOURCES(MERCURY)	)	

TESTIMONY OF ROBERT J. KALEEL

My name is Robert Kaleel. I am the Manager of the Air Quality Planning Section in the Division of Air Pollution Control, Bureau of Air at the Illinois Environmental Protection Agency ("Agency"). I have been employed by the Agency for twenty-five years in the areas of air quality modeling, planning, and regulatory development. I have also worked for a private consulting company in the fields of atmospheric modeling, air permitting, and air pollution meteorology. I have a Bachelor of Science degree in meteorology from Northern Illinois University.

In my current position at the Agency, I am responsible for overseeing the development of technical analyses in support various regulatory proposals, including the proposed mercury regulations that are the subject of this rulemaking. I am available to provide testimony in this matter.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R06-25
PROPOSED NEW 35 ILL. ADM. CODE 225	)	(Rulemaking – Air)
CONTROL OF EMISSIONS FROM	)	
LARGE COMBUSTION SOURCES(MERCURY)	)	

TESTIMONY OF SID NELSON JR.

QUALIFICATIONS

My name is Sid Nelson Jr. I am here today for Sorbent Technologies Corporation, a provider of power plant mercury emission control, where I serve as President.

I have a Bachelor of Science degree with highest distinction in engineering from The Pennsylvania State University and a law degree from the University of Arizona. I also have a Masters degree in Public Policy analysis from Harvard University, where I was a Kennedy Fellow of Science, Technology and Public Policy.

I have spent the vast bulk of my career in the coal and energy field, including early positions with the former U.S. Steel Corporation in their coal and resource development group and at Booz-Allen & Hamilton in their coal-industry management-consulting practice.

I have been with Sorbent Technologies Corporation for over fifteen years, the last five years as its President. I have been specifically involved in *mercury* emission control activities at Sorbent Technologies for over ten years.

I appear today to testify on some of our full-scale results, on my understanding of the results of others, and on the commercial availability of these technologies.

RESULTS OF FULL-SCALE MERCURY CONTROL DEMONSTRATIONS TO DATE.

Is it technologically possible to reduce mercury emissions at each Illinois power plant by 90% today?

Of course it is. At a minimum selective catalytic reduction (SCR) systems and wet or dry sulfur dioxide scrubbers could be installed at these plants and these have been shown to be widely capable of 90%+ mercury removal. While SCR and scrubbers would also have the large benefits of reducing sulfur dioxide and NOx, they would be expensive for mercury alone, although the ability to sell SO2 and NOx allowances could mitigate their costs.

Are there inexpensive retrofit technologies available to get 90%+ at Illinois plants? For the vast bulk of Illinois plants, the answer to this is also yes, even today.

I am going to concentrate my remarks on sorbent injection technologies, in particular on activated carbon injection technologies for mercury reductions. Variations of this technology have now been tested at full scale at probably thirty different plants - and counting - so there is a large knowledge base of its capabilities. With this technology the resulting costs and results vary somewhat with the particular plant situation: first with the coal that is being burned and, second, with the type of existing pollution control equipment at the plant.

Subbituminous Coals with Cold-Side ESPs.

The dominant configuration for coal-fired power plants in Illinois is a subbituminous coal with a cold-side electrostatic precipitator (ESP). Fortunately, the technology exists to retrofit this particular configuration very inexpensively. My company has been involved in two full-scale thirty-day continuous runs on this combustion with a product that we produce, called B-PAC (for brominated powdered activated carbon). Very high mercury removal rates were demonstrated at very low sorbent consumption rates and costs.

In a Department of Energy sponsored demonstration two years ago at the St. Clair Power Plant of Detroit Edison, my company injected our B-PACs sorbents continuously for thirty days at a low injection rate of 3 lbs per million cubic feet of gas into a flue gas. The St. Clair boilers are primarily fired by subbituminous coal, with about 15% of bituminous coal blended in. We averaged 94% mercury removal over the period with the plant operating as it usually does, ramping up and down, changing the coal fired as necessary.

Similarly last fall, in another DOE program with the Energy and Environment Research Center of the University of North Dakota, the URS Corporation injected our B-PAC sorbent into a 100% subbituminous-coal-fired flue gas stream with a cold-side ESP at Great River Energy's Stanton Station continuously for thirty-days. Here they weren't after 90% mercury removal, just 80%, so they injected at a lower rate of only 2 lbs of sorbent per million cubic feet of gas. Even at the lower rate they averaged over 80% mercury removal. In earlier short-term parametric tests at this plant, when they injected at 3 lb/MMacf, they achieved over 90% reductions, as a St. Clair.

A competitor of ours, called ADA-ES, injected a Norit carbon, similarly halogenated, brominated like ours. Its called Darco Hg LH. They injected that sorbent at 3.3 lbs per million cubic feet of gas for nearly thirty-days at the Meramec Station of Ameren, one of the utilities involved here in Illinois and achieved over 90% average removal over that period as well. These brominated carbons have been demonstrated at other plants with western coals and dry scrubbers, as well, and have uniformly achieved 90% mercury removal or better.

With sorbent injection, if you wanted 95% removal you would simply inject more sorbent. The quantity of sorbent, particularly a brominated sorbent, in a subbituminous plant that you inject is directly proportional to the mercury removal that you will achieve.

This technology is commercially available today. We supply the sorbent. Norit Americas supplies the sorbent. Calgon Carbon can supply similar sorbents. In the future, there will likely be others as well.

Hot-Side ESPs with Subbituminous Coal

There are three boilers in Illinois that burn subbituminous coal with Hot-Side ESPs, which operate at elevated temperatures. One of them is under a consent decree to install a fabric filter on the cold-side and this will mean that it can operate very cheaply with traditional sorbents.

The two others, Will County #3 and a boiler in Waukegan, however, can inject hot-side sorbents. My company has a variation of our B-PAC sorbents called H-PAC, that on bituminous coals at full-scale we have demonstrated high mercury removals even at the elevated temperatures of hot-side ESPs. This was demonstrated in short-term tests at Duke Power's Cliffside Station and then in a thirty-day test at Duke Power's Buck Plant. Because these plants burn bituminous coal, a higher injection rate of carbon was needed to reach equivalent mercury removal rates.

Our H-PAC sorbent for the hot-side ESPs was able to achieve high mercury removals, but we weren't injecting at rates capable of 90% at these plants. We weren't trying to achieve 90% at these plants, but at an injection rate of 10 lbs of H-PAC per million cubic feet of gas in the testing at Buck we achieved about 70% mercury removal. Now there are things that we could have done at Buck, some relatively low-cost capital equipment changes that would have allowed us to achieve higher mercury removal. However, because it was only a temporary test we did not do those things.

We believe that because it is so much easier to achieve high mercury reductions with subbituminous coals with these sorbents, that at Waukegan and Will County we will be able to achieve 90% at significantly lower injection rates than needed at Buck. This would save the utility a little bit of money. We will in fact be testing at Will County here in Illinois in a DOE program for a thirty-day continuous test on the hot-side there early next year to confirm this. Of course, even if we are unsuccessful, there are other technology options that can be applied. Turning Will County into a cold-side ESP arrangement and injecting the standard sorbent is just one example and can be done relatively inexpensively.

“Concrete-Friendly” Sorbents

A number of Illinois plants are able to sell their fly ash as a substitute for cement in concrete. This is a subset of plants, but it is socially beneficial in that there is less cement that has to be produced and do not have to dispose of the fly ash. Unfortunately, with our particular technology, activated carbon injection, the slightest bit of plain activated carbon that gets into that fly ash generally makes the fly ash un-useable for this re-use application.

Previous testimony may have previously described a few technologies to get around this problem, the Toxicon and Toxicon II technologies. There is also the possibility of inorganic sorbents, non-carbon based sorbents, which a number of manufacturers are testing. Amended Silicates was recently involved in a thirty-day test at an Ohio plant with their inorganic sorbent. Englehard Corporation has one as well. There are also sacrificial chemicals that are under development to be added to the slurry or new air entrainment admixture chemicals that are unaffected by PAC that are under development.

My company has a new product called C-PAC which is a version of the B-PAC which does not adversely affect the air entrainment admixtures that cause the problem with use of fly ash containing carbon in concrete. We are going to be demonstrating this C-PAC product in just a few months at full-scale in a DOE program and the Crawford Plant of Midwest Generation in the Chicago area. This will involve a thirty-day continuous test at injection rates capable or targeting 90% mercury removal or better and then extensive testing of the concretes made from the fly ash. We are confident, based on our prior testing, that we will be able to achieve this, but we will know for sure at full-scale at the end of the summer. That product will be available to plants in Illinois that will allow them to continue to sell their fly ash.

Plants That Burn Southern Illinois Bituminous Coal

Activated carbon injection is also applicable to the plants that continue to burn Southern Illinois bituminous coal. I am not aware of any large scale, long-term testing at plants that burn these coals, so I am going to have to extrapolate from other bituminous coals that are burned in the East.

My company has done full-scale tests of our B-PAC with various eastern bituminous coals and had good results, albeit with somewhat higher injection rates than with subbituminous coals. For example, we recently completed a thirty-day run with a bituminous at Progress Energy's Boiler #1 at their Lee Plant. These we averaged 85% mercury removal, 80% due to the sorbent, over the month at an injection rate of 8 lbs. of sorbent per million-cubic-feet of gas.

The only Illinois boilers that I am aware of where 90% mercury removal with ACI may be an issue are those with high sulfur trioxide in their flue gas. These could be boilers burning Illinois coal and having selective catalytic reduction, or the co-injection of trona with PAC, may be the lowest-cost route for these few boilers. We have also done short-term tests at Duke Power's Allen Plant and at Public Service of New Hampshire's Merrimack Station. It is not anticipated in North Carolina that they are going to require 90% mercury removal, so we have targeted about 80% mercury removal in our North Carolina tests. To achieve 90%, we would simply inject the sorbent at a slightly higher rate.

COMMERCIAL AVAILABILITY OF ACTIVATED CARBON INJECTION

Is activated carbon injection (ACI) technology commercially-available today? Of course it is. Our silo system subcontractor, for example, has installed 40 such systems for mercury reductions at waste incinerators and they have operated reliably for many years.

Moreover, these systems and sorbents are commercially available today for power plants as well, and from multiple suppliers, so they will certainly be available for installation before 2009.

Two things are required for ACI: first, the silo/feeder systems to inject the carbons, and second, the carbons themselves.

Silo/Feeder/Injection Systems

The capital equipment – the silo/feeder/injection systems – are simple and tiny compared to typical utility air pollution control equipment. They store the carbon, which is delivered by bulk truck, and meter it through a pipe to the ductwork, where it is blown into the flowing flue gas through simple open-ended lances.

Such low-tech equipment is at least fifty years old and can probably be supplied by hundreds of U.S. companies if necessary. Working with our experienced silo/feeding system subcontractor, Sorbent Technologies has begun bidding on the installation of such systems for a number of utilities. A competitor of ours, ADA-ES, has already accepted orders for eight of these systems at five power plants and is currently in the process of supplying them.

On a non-expedited basis, it takes about six months from order to actual system operation at the plant site. Little to no source specialized labor is required. The silo/feeder systems are constructed off-site and simply installed on a concrete platform at the utility site. They can be installed while the plant is still operating.

Activated Carbon Sorbents

The activated carbons are commercially available in bulk as well. Three large U.S. activated carbon manufacturers are Norit, Calgon, MeadWestvaco, who each supply tens of thousands of tons of sorbents annually to many different industries. Smaller carbon producers and importers of foreign-produced carbons also supply these materials. My company's plant in Ohio brominates carbons that we purchase from others and its capacity can be easily expanded to meet any future increases in demand.

Characteristics of Activated Carbon Injection Technologies

In addition to their low costs, there are numerous advantages to activated carbon injection for mercury control at power plants.

- Installation times are quick
- No specialized trade labor is required
- As most of the costs are in the sorbents actually consumed, costs are proportional to the level of actual plant operations, so smaller plants or peaking plants are not disadvantaged.
- The same capital equipment can be used as technology advances and better sorbents are developed.
- Because so little capital equipment is needed, there are no sunk costs to be wasted if a scrubber is installed later. Mercury reductions can be started today.

SUMMARY

The conclusion of my testimony is that the technologies for mercury removal for the plants in Illinois are commercially available today and will be even more available and lower in cost in 2009. Sorbent Technologies Corporation and other companies have developed a number of power plant mercury emission reduction technologies which have been demonstrated to achieve 90% mercury removal at full-scale at numerous power plants around the country. We can commercially supply, today, the sorbents and systems necessary for easily-retrofitable power plant mercury reductions in Illinois.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R06-25
PROPOSED NEW 35 ILL. ADM. CODE 225	)	(Rulemaking – Air)
CONTROL OF EMISSIONS FROM	)	
LARGE COMBUSTION SOURCES(MERCURY)	)	

TESTIMONY OF JEFFREY W. SPRAGUE

My name is Jeffrey W. Sprague. I am an Environmental Protection Specialist and Assistant Modeling Unit Manager for the Air Quality Planning Section, Division of Air Pollution Control, Illinois Environmental Protection Agency. I have been employed with the Agency since 1988. I graduated from Western Washington University with a Bachelor of Science degree in Geology and minors in chemistry and environmental studies. I have pursued graduate studies at Western Washington University in geology and the University of Illinois at Champaign-Urbana in geology and soil science. My duties at IEPA have included emissions processing for ozone and PM2.5 SIP development, emission inventory preparation, dispersion modeling in support of Agency permit activity and PM-10 SIP development, enhancement of Agency air toxics modeling, ecological risk assessment reviews, and receptor modeling capabilities, and addressing agriculture-related air quality issues. I have served on the Agency's Mercury Workgroup, and I currently represent the Agency on the Great Lakes Commission's Great Lakes Air Deposition Program Management Team.

The discussion of mercury impacts on human health in Section 3.0 of the <u>Technical Support Document for Reducing Mercury Emissions from Coal-Fired Electric Generating Units</u> (AQPSTR 06-02) is a synthesis of statements from <u>Michigan's Mercury Electric Utility Workgroup Final Report on Mercury Emissions from Coal-Fired Power Plants</u> (June 20, 2005) and those from a report prepared for the Illinois EPA by Deborah C. Rice, Ph.D. entitled

Review of the Nervous System and Cardiovascular Effects of Methylmercury Exposure (March, 2006). It is generally acknowledged that mercury in various forms can induce toxic responses in the human body, however, methylmercury exposure resulting from fish ingestion poses the greatest exposure risk to human beings. Historical acute exposure incidents as well as evidence from low level exposures have provided information on the symptoms and neurological effects of methylmercury poisoning. Such effects include sensory impairment, mental deficits, muscle weekness, tremor, hypersensitive reflexes and other neuropathological manifestations. Longitudinal prospective epidemiological studies for populations in New Zealand, the Seychelles Islands, and the Faroe Islands have yielded results that markedly contrast, but which are not discordant with respect to mercury effects on IQ. An integrative analysis of these three studies showed a decrement of 0.13 IQ point for each 1 ppm increase in maternal hair mercury. Cross-sectional studies assessing development in children have shown test outcomes significantly associated with mercury hair concentrations or blood mercury levels. Similarly, cognitive function and motor function tests on adults have shown associations with total urinary mercury, mercury in blood, and/or hair mercury content. The impact on the human body of methylmercury exposure includes potential cardiovascular and coronary disease. In a recent study of 2500 men in Finland, the highest measured hair mercury concentrations were associated with increased incidences of myocardial infarction. The results of this study also indicate that high levels of methylmercury in the body may negate the beneficial effects of fish oils in protecting against coronary disease. The NHANES survey and other studies intended to provide information on mercury body burdens in the U.S. population provide evidence of a strong association between fish consumption and increased mercury levels. For some populations, a substantial percentage of individuals have methylmercury body burdens greater than that associated with the reference dose (0.1 micrograms/kg/day). The reference dose represents an estimation of a daily exposure to the human population (including sensitive subgroups) that is likely to be without appreciable risk of deleterious effects during a lifetime. The Centers for Disease Control has estimated that approximately 6% of women of childbearing age have blood mercury levels at or exceeding the reference dose.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R06-25
PROPOSED NEW 35 ILL. ADM. CODE 225	)	(Rulemaking – Air)
CONTROL OF EMISSIONS FROM	)	
LARGE COMBUSTION SOURCES(MERCURY)	)	

AMENDED TESTIMONY OF CHRISTOPHER ROMAINE

Qualifications

My name is Christopher Romaine. I am here today for the Illinois Environmental Protection Agency (Agency), where I am the Manager of the Construction Unit in the Permit Section in the Bureau of Air.

I have a Bachelor of Science degree in engineering from Brown University and have completed coursework towards a Masters Degree in Environmental Engineering from Southern Illinois University. I am a Registered Professional Engineer in the State of Illinois.

I joined the Agency in June 1976, at a junior level in the Permit Section in the Division of Air Pollution Control. I am currently the Manager of the Construction Unit in the Permit Section. I previously served as the Manager of the New Source Review Unit, Manager of the Utility Unit, and Manager of the Joint Utility/Construction Unit, all in the Permit Section.

In particular, in 1999, I became Manager of the Utility Unit in the Permit Section, after about a year and a half serving as the Acting Manager. As the Manager of the Utility Unit, I supervised the permit engineers who reviewed air pollution control permit applications for electric power plants, including applications for proposed new power plants, construction permit applications for projects at existing power plants, and applications for operating permits for power plants.

My involvement in the permitting of coal-fired power plants has continued to the present day. When the Joint Utility-Construction Unit was formed in 2001, consolidating the separate Utility and Construction Units, I continued to supervise the engineers who worked on power plant applications. It is only recently, with the issuance of the Clean Air Act Permit Program (CAAPP) Permits to Illinois' coal-fired power plants, that formal responsibility for future work on CAAPP applications for power plants has begun to be transferred over to the CAAPP Unit in the Permit Section. However, the Construction Unit continues to process construction permit applications involving power plants.

In addition to my duties related to permitting, in my tenure with the Agency, I have assisted in the development of a number of regulatory programs for stationary sources. These programs include Nonattainment New Source Review (NA NSR) for proposed construction projects in nonattainment areas, Reasonable Available Control Technology (RACT) for volatile organic material emissions for certain categories of emissions units, the Clean Air Act Permit Program (CAAPP), and the Emissions Reduction Market System (ERMS).

The purpose of my testimony is to provide additional explanation for various provisions of the proposed rules.

Definitions

Many of the definitions in proposed 35 IAC 225.130 are transferred over from the Clean Air Mercury Rule (CAMR). The proposed rule also includes definitions for five terms that are not found in CAMR: Averaging Demonstration, Gross Electrical Output, Input Mercury, Output-Based Emission Standard, and Rolling 12-Month Basis. Definitions of these terms were developed by the Agency to facilitate the understanding and implementation of the proposed rules. With the exception of the definition of "Rolling 12-Month Basis," these definitions are self-explanatory.

The definition of "Rolling 12-Month Basis" is a particularly important definition in the proposed rules, as it defines the compliance time period associated with the proposed emission standards. The compliance time period for these emission standards is 12 successive months. A separate compliance time period applies for each month, as a new month is added and the oldest month is dropped from the 12 month long period. In other words, compliance is determined on the basis of 12-months of data, rolled on a monthly basis or a “rolling 12-month basis.”

There are two exceptions or refinements to this general approach. The first addresses months in which a unit does not operate when compliance is being determined for an individual unit. The proposed rules would not include a month in which such a unit does not operate in the compliance determination. Instead, the compliance determination in subsequent months would “skip” a month in which the unit did not operate and would be based on data from 12 months in which the unit actually operated. This is consistent with the approach taken by USEPA to compliance determinations for mercury emissions under the New Source Performance Standards for Electric Utility Steam Generating Units, which are also made on a 12-month rolling basis. (Refer to 40 CFR 60.50Da(h)(2)(iii).) The second exception addresses a month in which a unit does not operate when compliance is being determined for a group of units on an aggregate basis. When compliance is being determined for a group of units on an aggregate basis, the proposed rule would only skip a month in which all units covered by the compliance demonstration do not operate. Compliance determinations would include months in which any of the units covered by a demonstration is operated, as is necessary so that a compliance determination is made for each month in which any unit in the group is operated.

Incidentally, one consequence of applying the emission standards in the proposed rules on a rolling 12-month basis is that compliance with the numerical emission standards will not be able to be determined for the first 11 months after July 1, 2009, when the standards become “effective.” The earliest date that the first formal determinations of compliance with these standards can occur is July 1, 2010. This is the earliest date on which a total 12 months of data will be available for an existing unit or group of units, for the period from July 1, 2009 through June 30, 2010, from which compliance with the emission standards can be numerically determined.

Compliance Requirements

The compliance requirements set forth in proposed 35 IAC 225.210 summarize the obligations that would apply to the operation of a unit under the proposed rules. This Section reflects the approach to such matters in CAMR, with the specific provisions paralleling the relevant provisions in CAMR.

Permitting Provisions

The permitting requirements set forth in proposed 35 IAC 225.220 address the implications of the proposed rules for permitting. Like the compliance requirements in proposed 35 IAC 225.210, this Section is based on provision found in CAMR. However, unlike CAMR, proposed 35 IAC 225.220 would not require sources to obtain separate mercury budget permits for units subject to the proposed rules. The requirements of the proposed rules would be addressed in other permits that are already required for the units, most commonly CAAPP Permits, along with the other applicable emission standards and requirements that apply to the units. As related to control of mercury emissions, these permits and the applications for such permits would have to address the informational and procedural requirements that USEPA has determined are appropriate for these applications and permits under CAMR. For example, the applications for such permits must include the Identification Number assigned to the source by the federal Office of Regulatory Information Systems, the identification of the units at the source, the intended approach to required monitoring under the rules, and the intended approach to compliance with the emissions standards under the rules.

Emission Standards for Units at Existing Sources

Proposed 35 IAC 225.230 sets forth the mercury emission standards for units at existing sources. At a basic level, these standards require that mercury emissions from an existing unit either not exceed 0.0080 lb mercury/GWh gross electrical output or be controlled by a minimum of 90-percent reduction from the input mercury contained in the coal that is burned in the unit. The proposed rules have an emission standard expressed in terms of electrical output, as well as an emission standard expressed in terms of the reduction in input mercury, to specifically address units that are burning washed Illinois basin coal, as has been discussed in detail in the testimony of other Agency witnesses. These standards take effect beginning July 1, 2009. However, as already explained, because the standards apply on a rolling 12-month basis, the earliest date that a formal determination of compliance could be made with these standards would be July 1, 2010.

Proposed 35 IAC 225.230 becomes more involved because it addresses how these basic standards would actually be applied to a unit or units at source under difference circumstances. It also includes specific equations setting forth how relevant data is to be handled for the purpose of determining compliance with the applicable emission standards.

The simplest circumstance is that compliance with the emission standards is demonstrated for an individual unit <u>and</u> the applicable emission standard does not change during the particular 12-month rolling period. In such case, as addressed by proposed 35 IAC 225.230(a), compliance can be directly determined in the terms of the applicable standard. If the unit is complying with the output based standard, the total emissions of mercury during each 12-month rolling compliance time period would be divided by the total gross electrical output during the same period. The result would be the actual mercury emission of the unit, in lbs per GWh, which would then be compared to the applicable standard, 0.0080 lb/GWh. If the unit is complying with the emission reduction standard, the total emissions of mercury during the 12-month rolling compliance time period would be compared to the total amount of input mercury during the same period. The result would be expressed in terms of the reduction efficiency for input mercury, in percent, which would then be compared to the applicable standard, 90 percent.

The next circumstance, as addressed by proposed 35 IAC 225.230(b), is that compliance with the emission standards is demonstrated for an individual unit and <u>the applicable emission standard changes during the particular 12-month rolling period</u>. This circumstance must be considered because a source could switch the coal supply to a unit during a 12-month period, going to Illinois basin coal from western coal or vice versa. This would also likely also trigger a shift in the emission standard with which the unit elects to comply. In this circumstance, it is not possible to directly determine compliance in terms of an applicable emission standard, since both standards applied during the 12-month period. To address this circumstance, the compliance of the unit would be evaluated by comparing the actual emissions of mercury for the 12-month rolling period to the allowable emission of mercury during the same period. If the actual emissions for the 12-

month period are equal to or less than the allowable emissions for the 12-month period, a unit would be in compliance. This restructuring of the compliance demonstration does not effect the determination of actual emissions. However, the allowable emissions must be calculated. For a month in which the source elected to comply with the output based standard, the allowable emissions would be calculated as the product of the gross electrical output for the month and the output based standard, i.e., 0.008 lb/GWh. For a month in which the source elected to comply with the reduction standard, the allowable emissions would be calculated as the product of the input mercury and the allowed emissions after the required reduction, i.e., 10 percent or 0.10. The allowable emissions for the 12-month rolling period are the sum of the allowable emissions for each of the 12 months in the rolling period.

The next circumstance, as addressed by proposed 35 IAC 225.230(c), is that compliance with the emission standards <u>must be demonstrated for two or more units at a plant as a group</u> because mercury emission data is only available for the units as a group. This circumstance occurs because certain units share common stacks. For these units, mercury emission monitoring will be most reliably and economically conducted with a single monitoring system for the emissions of mercury from the common stack. This is the approach that is currently being used for units with shared stacks for monitoring for emissions of sulfur dioxide (SO_2) and nitrogen oxide (NOx) under the Acid Rain and NOx Trading Programs. For units that are served by a single emissions monitoring system in a common stack, it will be necessary to approach the physically distinct units as if they were a single unit for the purpose of demonstrating compliance. Given the need to combine data for gross electrical output or input mercury from two or more units, it will again be simpler if this compliance demonstration is made by comparing the actual and allowable emissions of mercury during each 12-month running compliance time period.

The last circumstance, as addressed by proposed 35 IAC 225.230(d), is that a <u>source elects to demonstrate compliance on a source-wide basis</u>. In this circumstance, the compliance demonstration must be carried out by comparing the total actual and allowable emissions of mercury of all the units at the source for each 12-month rolling compliance time period. The proposed rules further specify that if a source has elected to show compliance on a source-wide basis and fails to show compliance, all units shall be considered to be out of compliance for the final month of the 12-month rolling period. This approach was taken because a single party, the owner or operator, will be responsible for all units covered by the compliance demonstration. It is not necessary to specifically assign culpabity for noncompliance to a particular unit at the source, and indeed noncompliance can be broadly attributed to the collective performance of the units.

Averaging Demonstrations for Existing Units

Proposed 35 IAC 225.232 provides the additional flexibility that is present in the proposed rules for Phase 1, through December 31, 2013. (In fact, when one considers the consequences of the 12-month rolling compliance time period, this additional flexibility is only fully available through January 31, 2013.) This additional flexibility is present during Phase 1 as companies with existing sources that meet a minimum criterion for control of mercury emissions can also show compliance with the proposed standards using system-wide compliance demonstrations, which are referred to as "averaging demonstrations" in the proposed rules. These compliance demonstrations would include units at more than one source. Compliance would be determined by comparing the total actual and allowable emissions of mercury of all the units covered by the averaging demonstration for each 12-month rolling compliance time period.

While averaging demonstrations can be used through December 31, 2013, companies will have to be taking any actions that are needed to show compliance on a source-wide basis, without reliance on an averaging demonstration, well before December 31, 2013. This is because the first 12-month rolling period after averaging demonstrations cease to be available will actually cover the 12-month period from February 1, 2012 through January 31, 2013.

The minimum requirement for a source to be included in an averaging demonstration is that the source by itself must also comply with one of the following emission standards on a source-wide basis for the period covered by the demonstration: (1) An emission standard of 0.020 lb mercury/GWh gross electrical output; or (2) A minimum 75-percent reduction of input mercury. This requirement assures that technology for control of mercury emissions is utilized on each source, and most likely each unit, that is covered by a multi-source compliance demonstration.

Companies with more than one source can only participate in averaging demonstrations that include other sources that they own or operate. Companies or organizations with only a single source subject to the proposed rules (i.e., City, Water, Light & Power, City of Springfield; Electric Energy, Inc.; Kincaid Generating Station; and Southern Illinois Power Cooperative/Marion Generating Station) can only participate in demonstrations with other companies or organizations that only have a single source. In addition, for a company or organization with only a single source, participation in averaging demonstrations must be authorized through federally enforceable permit conditions for each source participating in the demonstration. This is intended to assure that the role and the responsibilities of the different entities involved in the averaging demonstration are well defined.

If averaging is used to demonstrate compliance, the effect of a failure to demonstrate compliance will be that the compliance status of each source will be determined as if the plant were not covered by an averaging demonstration.

Existing Units Scheduled for Permanent Shutdown

Proposed 35 IAC 225.235 contains provisions that would allow a source to obtain an exemption from the proposed emission standards for an existing unit that will be permanently shut down soon after July 1, 2009. This exemption was included in the rules because the cost for installation of activated carbon injection systems were not believed to be warranted for units that would shortly be permanently shut down. A unit for which such an exemption had been obtained could not be included when determining whether any other units at a source or other sources are in compliance with the proposed emission standards under a source-wide compliance demonstration or averaging demonstration.

This exemption specifically responds to the circumstances of City Water, Light and Power (CWLP), the municipally owned and operated power supply for the residents of the City of Springfield. CWLP has submitted a construction permit application to build a new coal-fired generating unit, Dallman Unit 4, at its existing power plant adjacent to Lake Springfield. The new unit is being developed to meet the future power needs of Springfield. The new unit would also replace the two Lakeside Units at the plant, which are the oldest units now at the plant. The Lakeside Units would be permanently shut down after new Dallman 4 is constructed and operational. As part of the air pollution control permitting for new Dallman Unit 4, CWLP is relying upon decreases in emissions from the shut down of the Lakeside Units

Depending on the circumstances surrounding the shut down unit, different dates are proposed for when existing units must be scheduled to be shut down to qualify for exemption from the emission standards, For existing units for which the owner operator is constructing a new unit or other generating units to specifically replace the existing units, as is occurring with CWLP's two Lakeside Units, the existing units must be scheduled to be shut down by December 31, 2011. For existing units for which the owner or operator is not constructing a new unit or other generating units to specifically replace the existing units, the existing units must be scheduled to be shut down a year earlier, by December 31, 2010 to qualify for the exemption. This distinction was made because construction of a new generating unit is a challenging and lengthy undertaking. The source that is replacing a unit should be provided more time to carry out the construction of a replacement unit or other new generating capacity than the source that is only retiring a unit and relying on other existing units, which are already operating, to make up for the shut down unit. This distinction also recognizes the significant efforts and commitment of a source that is actively engaged in developing a replacement unit or developing other new generating capacity.

The exemption does include a provision for unforeseen events that would delay the scheduled shut down of an exempted unit. A source must permanently shut down the unit by the applicable deadline unless the source submits a demonstration to Agency before such date showing that circumstances beyond its reasonable control (such as protracted delays in construction activity for the new replacement units, unanticipated outage of another unit, or protracted shakedown of a replacement unit) have occurred that interfere with the plan for permanent shut down of the existing unit. In such circumstances, the deadline for shut down of the existing unit may be extended for up to one year if the unit is not being replaced or up to 18 months if the unit is being replaced, provided, however, that after December 31, 2012, the existing unit shall only operate as a back-up unit.

Procedural requirements accompany the exemption to ensure that reliance upon the exemption is carefully considered by sources and occurs in a timely manner and that that the exemption is not misused by sources. Before the effective date of the proposed emission standards, i.e., by June 30, 2009, a source must notify the Agency that it is planning to permanently shut down the unit. In addition, the source must have applied for a construction permit or be actively pursuing a federally enforceable agreement that requires the unit to be permanently shut down as needed to qualify for the exemption. The source must also have applied for revisions to the operating permit(s) for the unit to include provisions that terminate the authorization to operate the unit in a manner consistent with the exemption. By July 1, 2010, the earliest date that compliance with the proposed numerical emission standards can be determined, the requirement to permanently shut down a source must be embodied in a federally enforceable permit or other enforceable agreement.

Lastly, the exemption specifies that if a unit for which the exemption is relied upon is not shut down in a timely manner, the unit shall thereafter be considered a new unit for the purposes of the proposed rules. This is a final measure to address any possible abuse of the exemption.

Emission Standards for New Sources

Proposed 35 IAC 225.237 sets forth the mercury emission standards for units at new sources. While the standards are numerically identical to those for units at existing source, units at new sources must comply with applicable emission standards on an individual, unit-by-unit basis. Unlike the provisions for units at existing sources, compliance cannot be shown on a source-wide basis or, as allowed during Phase 1 of the proposed rules, with an averaging demonstration. This is appropriate because the units at new sources will be controlled with Best Available Control Technology (BACT) under the federal rules for Prevention of Significant Deterioration (PSD) 40 CFR 52.21. As a result, control of mercury emissions through co-benefit will be maximized. Activated carbon injection systems can also be installed on these units as original equipment, so as to maximize the capabilities of this technology to control mercury emissions.

The effective date of the emission standards for new units is set to match the effective date of the mercury emission standard that would also apply to a new units under the federal New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units, 40 CFR 60.45Da. This was done for administrative convenience, so that the compliance determinations under the NSPS and proposed rules for new units start at the same time and continue on the same schedule. Since the emission standard of the NSPS does not immediately become effective upon initial startup of a new unit, this approach also allows time for the shakedown of the new unit as related to the control of mercury emissions and the orderly shakedown and certification of the continuous emissions monitoring system for mercury. During the period before the emission standards take effect, a source is under the general obligation to operate a unit in accordance with good air pollution control practices to minimize emissions.

Emissions Monitoring

As explained in the Technical Support Document, the requirements in the proposed rule for monitoring of mercury emissions are essentially identical to the monitoring that would be required under CAMR. Accordingly, the proposed rule refers to the provisions for emissions monitoring adopted by USEPA at 40 CFR Part 75, Subpart I, Hg Mass Emission Provisions, and 40 CFR Part 75, Appendix K, Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems. The proposed rule also allows use of the excepted “low mass” monitoring methodology, as adopted by USEPA at 40 CFR 75.81(b), for units that have annual emissions of no more than 29.0 pounds of mercury. Other aspects of the proposed rule related to emissions monitoring are also consistent with provisions of the CAMR. For example, the owner or operator of an existing unit must begin monitoring for mercury emissions no later than January 1, 2009, as would be required under CAMR. Emissions monitors must be certified and generally operated as would be required under CAMR. Any alternative emission monitoring methods must be approved by USEPA. The technical feasibility of the required monitoring for mercury emissions was addressed by USEPA as part of its rulemaking to adopt the CAMR. (For example, refer to 70 FR 28633, May 18, 2005.)

Other Monitoring Requirements

The proposed rule also includes monitoring requirements that are not directly related to mercury emissions but are necessary to determine compliance with the proposed emission standards. The owner or operator of a unit complying with the output-based emission standard would be "required" to conduct operational monitoring for the electrical output from the unit, as measured at the generator. Since accurate information on electrical output is already needed by a source for operational reasons and this data is readily collected by watt meters designed for this specific purpose, the proposed rule does not specify particular monitoring methodology that must be used for the collection of this data. The rule also does not require that this data be collected until this data will be needed to determine compliance.

The owner or operator of a unit complying with the 90 percent reduction standard would be required to conduct analyses of the coal being burned in the unit to determine its mercury content. This information would then be used to determine the amount of mercury in the coal going into the unit so that the mercury removal efficiency achieved by the control devices on the unit could be calculated, as related to the 90 percent reduction standard. While most sources that will be subject to this proposed rule already collect and analyze coal samples on a routine basis for operational reasons, this activity does not extend to analysis for mercury content. The provisions for coal sampling in the proposed rule are intended to ensure an accurate determination of the input mercury to the subject units. Since the mercury content of coal varies, even when coming from a single mine and coal seam, and the amount of coal consumed by an unit can vary from day to day, daily sampling of the coal supply to units is necessary. The coal supply must be sampled at a point after long-term storage, where the sample will be representative of the coal being burned in the unit on the day that the sample is taken. This location for coal sampling was selected after consultation with industry representatives to provide flexibility in the point at which samples are collected while ensuring that the resulting data accurately reflects the coal that is actually being burned in a unit.

Certain ASTM Methods were selected for the required analyses of coal. For mercury, these are ASTM D6414-01, "Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by Acid Extraction or Wet Oxidation/Cold Vapor Atomic Absorption," and ASTM D3684-01, "Standard Test Method for Total Mercury in Coal by the Oxygen Bomb Combustion/Atomic Absorption Method." These methods were chosen by the Agency after consultation with industry representatives and experts on coal analysis because these methods are accurate, sources and commercial laboratories are familiar with these methods, and the costs of these methods are reasonable.

The proposed rule would require that a source begin collecting and analyzing coal samples at least 30 days before data is needed to determine compliance, if it is reasonably possible to do so. This approach was taken to reasonably ensure that data is being properly collected when it is finally needed for the purpose of determining compliance. However, if a unit has been out of service, such that meaningful sampling and analysis of the coal supply could not be conducted in advance of the time at which data is needed, a source must begin to conduct this monitoring when the unit is returned to service.

Conclusion

In conclusion, the provisions of the proposed rules have been carefully considered and developed to carry out the objectives for the proposed rulemaking.

STATE OF ILLINOIS	**)**	
	)	**SS**
COUNTY OF SANGAMON	**)**	
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CERTIFICATE OF SERVICE

I, the undersigned, an attorney, state that I have served electronically the attached TESTIMONY OF DAVID C. FOERTER, EZRA D. HAUSMAN, Ph.D., ROBERT J. KALEEL, SID NELSON JR., and JEFFREY W. SPRAGUE, and AMENDED TESTIMONY OF CHRISTOPHER ROMAINE, upon the following person:

Dorothy Gunn
Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601-3218

and mailing it by first-class mail from Springfield, Illinois, with sufficient postage affixed to the following persons:

SEE ATTACHED SERVICE LIST

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY,

____
Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

Dated: April 28, 2006

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