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 OF FILING

TO:

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SEE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that on September 20, 2006, I the undersigned caused to be filed electronically with the Clerk of the Illinois Pollution Control Board the attached POST-HEARING COMMENTS, copies of which are herewith served upon you.

By: [s] Mary Frontczak
Mary Frontczak (Reg. No. 6209264)

DATED: September 20, 2006

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PRAIRIE STATE'S POST-HEARING COMMENTS

NOW COMES Participant PRAIRIE STATE GENERATING COMPANY, LLC, by and through its attorney, MARY FRONTCZAK, pursuant to 35 Ill. Adm. Code § 102108, and offers the following POST-HEARING COMMENTS in the above-captioned proposed rule:

I. THE PROPOSED RULE WITHOUT A TECHNOLOGY BASED STANDARD WILL NEGATIVELY IMPACT NEW GENERATION BURNING ILLINOIS COAL SUCH AS PRAIRIE STATE GENERATING STATION.

A. Technology has not been sufficiently tested on high sulfur coals (e.g., 9 lb. SO_2/mmBtu) such as Illinois Seams 5 and 6

Illinois Seams 5 and 6 coal have sulfur content on the order of 9 lb sulfur dioxide (SO_2) per million Btu or approximately 4% sulfur. This is classified as a high sulfur coal. As discussed in Prairie State's testimony at the hearing, there is very little information on the efficacy of mercury control technologies when high-sulfur coal is burned. Exhibit 80; Ms. Tickner, Hearing Transcript at 456 (August 15, 2006). That testimony is supported by the TSD and other witnesses, including those for IEPA. *See, e.g.*, TSD at 128 ("There is currently no test data on units with sulfur levels as high as those of Illinois coals."); Dr. Staudt, Hearing Transcript at 73 (June 22, 2006); Mr. DePriest, Hearing Transcript at

1230-31 (August 18, 2006). Mr. Nelson even suggested that technology may not be commercially available for high sulfur coals:

> It is commercial at least in the type of coals and the type of systems, like perhaps not a Conesville situation, but certainly in those types of systems that they have had successful demonstrations on.

Hearing Transcript at 73 (June 22, 2006).[1]

The control of mercury emissions at coal-fired power plants is extremely difficult for numerous reasons including the minute amount of mercury in stack gas. To date, short-term testing of mercury controls has occurred at only 28 coal-fired units -- those plants comprise about 2.3% of the coal-fired units in operation in the U.S. Despite the millions of dollars that DOE and industry have spent on this testing, DOE recently concluded that:

> while DOE is very encouraged by the results of our mercury control technology development efforts to date, ***there remain a number of critical technical and cost issues that need to be resolved through additional research before these technologies can be considered commercially available for all U.S. coals and the different coal-fired power plant configurations in operation in the United States.***

Exhibit 55 at p. 1 (emphasis in original). DOE plans to continue its mercury control technology testing program through at least 2009. EPA reached a similar conclusion about the state of mercury controls when it stated in the preamble of CAMR:

> We do not believe that such full scale [mercury] technologies can be developed and widely implemented within the next 5 years; however, it is reasonable that this can be accomplished over the next 13 years.

[1] Conesville is a facility in Ohio that burns high (3 to 4%) sulfur coal.

70 Fed. Reg. 28,619. Thus, there is no technical basis for assuming that 90% control of mercury is achievable at all coal-fired plants. This is particularly true for mercury control of high sulfur coals like those that will be burned by Prairie State.

Witnesses for IEPA and industry also concur that mercury removal from high sulfur coal is difficult. *See, e.g.*, Dr. Staudt, Hearing Transcript at 73, 98 (June 22, 2006); Mr. DePriest, Hearing Transcript at 1230 (August 18, 2006). As Dr. Staudt testified:

> And let me just state, in the case of the high sulfur situation, that is a situation that I've acknowledged is a difficult one both in the TSD and in my testimony,

Hearting Transcript at 73 (June 22, 2006). The apparent reason is sulfur trioxide (SO_3) interference. Dr. Staudt Hearing Transcript at 98 (June 22, 2006); Mr. DePriest, Hearing Transcript at 1230 (August 18, 2006).

Dr. Staudt did offer his unsupported opinion that the technology on new units will make it possible for them to meet the proposed standards. Hearing Transcript at 156 (June 21, 2006 pm). The limited available data actually suggests otherwise. In the one study to date on high sulfur coal at Conesville, preliminary data indicate that less than 50% mercury removal is achievable, around 30%. Exhibit 80, Attachment 3 (discussing Conesville study). The removal efficiency was even worse when brominated carbon was used (i.e., less than 25% mercury removal). *Id.* The experience at Conesville may not be directly transferable to what will be achievable at Prairie State due to different control technologies but it is the only test that is available to provide some insight into the impact high sulfur coal will have on mercury removal. Conesvillle has an ESP and wet FGD, while Prairie State will have an SCR, ESP, wet FGD and WESP. To Prairie State's knowledge, there are no data on mercury removal using all the above technology on high sulfur coal. Such lack of knowledge is why Prairie State believes the inclusion of a technology-based standard is necessary. That belief appears to be shared by Dr. Staudt at least for existing units. Hearing Transcript at 65 (June 21, 2006 pm); Hearing Transcript at 86-87 (June 22, 2006).

B. Guarantees are not available for 90% mercury control at new facilities

As indicated in Prairie State's testimony at the hearing, meaningful guarantees for mercury removal of 90% are not readily available, especially for use with high sulfur coals. Exhibit 80; Ms. Tickner, Hearing Transcript at 444-45, 465-69 (August 15, 2006). Prairie State has been working with Engineering, Procurement, and Construction (EPC) contractors for the past 3 years to determine the capabilities of the available technologies to reduce mercury emissions. Part of that effort has included ascertaining what guarantees are available for a new facility with respect to mercury removal.

The EPC contractors based on information from the vendors of the proposed technologies have indicated a willingness to guarantee around 84% mercury removal for Prairie State. Ms. Tickner, Hearing Transcript at 471 (August 15, 2006). Based on the mercury content of the Illinois coal to be burned at Prairie State (average of 0.09 ppm and worst case of 0.13 ppm), that removal efficiency is insufficient to meet either of the proposed standards.

As Mr. DePriest testified, guarantees are important to a prudent company because they "protect the owner from the investment he's making in that particular technology." Mr. DePriest, Hearing Transcript at 1150 (August 18, 2006). That is precisely what the owner of a new facility such as Prairie State is seeking from its EPC contractor — protection from its investment in all the control technology installed to control air emissions.

Unlike with retrofit applications of technology where a guarantee is limited to the equipment being installed, a new facility is looking for a guarantee from the EPC contractor to cover the cost of the facility — on the order of $2 to 3 billion dollars — if the control technologies do not perform as designed. The EPC contractor will wrap the various guarantees offered by the individual technology vendors into one overall guarantee to cover the scope of the project. *See* Excerpts from EPC Agreement (Attachment 1). The wrap is necessary in order to get financing for the project because lenders are unwilling to accept any risk related to the plant's inability to operate. *See* Mr. Romaine, Hearing Transcript at 162 (June 20, 2006) (indicating risk adverse investors as one of the reasons IEPA proposed the TTBS for new units). If an EPC guarantee cannot be obtained, it would be because the technology is not commercially available or proven. No one, neither banks nor equity owners, will build a $2 to 3 billion dollar plant and ***hope*** the control technology works. While activated carbon vendors may be willing to guarantee their product will achieve 90% removal (but only after they have had an opportunity to assess its effectiveness), their limited guarantee of $ 1 to 2 million is basically meaningless when compared to the overall cost of the facility. Moreover, given the preliminary results at Conesville discussed above, it is doubtful that activated carbon vendors will guarantee 90% removal on high sulfur coal.

II. TRADING SHOULD BE ALLOWED

Prairie State is concerned that IEPA's proposed rule creates future regulatory uncertainties for coal-fired power plants in Illinois. For new plants, these uncertainties are particularly problematic because they can affect the availability of capital to finance the project. One way to eliminate much of the regulatory uncertainty from the proposed rule would be for IEPA to adopt EPA's CAMR model trading rule and then layer the Illinois-specific provisions of the proposed rule on top of the model trading rule.

CAMR imposes a hard cap on nationwide mercury emissions. From 2010 to 2017, the cap is 38 tons per year; for 2018 and thereafter, the cap is reduced to 15 tons per year. CAMR requires that the mercury emissions from new coal-fired generating plants must be offset by reductions somewhere else in the U.S. either as the result of a decrease in emissions at an existing unit or by the retirement of a unit. EPA has allocated CAMR's nationwide cap among the states by establishing state mercury budgets based on the heat input of the coal-fired power plants in each state during the period 1998 to 2002. If a state opts out of the federal mercury cap-and-trade program, then CAMR mercury budget for that state becomes a hard cap on annual emissions from that state.[2]

Prairie State is concerned that at some point in the future, perhaps after 2018, utilities in Illinois will be in compliance with the requirements of IEPA's proposed rule yet the total emissions for the State would exceed Illinois' mercury budget. If that were to happen, Illinois would have to require further mercury reductions from coal-fired power plants in the State since plants would not be able to purchase allowances from outside the State to show compliance with the federal limit.[3]

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[2] In a recent set of comments on the New Mexico Environment Department's CAMR proposal, EPA Region 6 noted that if a state finalizes a rule with a "no trading" provision, then "it will actually be up to [the State] to ensure and demonstrate to EPA that you have met your State budget versus the utilities demonstrating to EPA that they have met the allowance provided to them by the State since they are not participants in the Federal cap-and-trade program." *See* Attachment 2.

[3] In fact, if Illinois were to allow trading, then in all likelihood coal-fired power plants in the State would probably bank sufficient allowances to avoid needing to purchase additional allowances in the event total Illinois emissions exceeds the state budget.

One way that Illinois emissions may exceed the state mercury budget is if mercury control technologies do not perform as advertised. As discussed above, this is of particular concern with mercury control of high sulfur coals like those to be burned by Prairie State.

A recurring theme whenever a trading program is discussed is that "hot spots" may be created. In the case of mercury, this claim is at the forefront of the trading debate. A central problem with the debate about mercury "hot spots" is that the term is rarely defined, and when it is, the definitions vary widely. Many who claim that "hot spots" will result from a mercury cap-and-trade program fail to offer any evidence that "hot spots" are being created by emissions from coal-fired power plants or plausible explanations of how mercury "hot spots" would be created by a mercury trading program.

The evidence presented before the Illinois Pollution Control Board demonstrates that a mercury cap-and-trade program will not create mercury "hot spots." The main modeling work on possible mercury "hot spots" presented by the IEPA is that of Dr. Gerald Keeler. Dr. Keeler used a receptor model to attempt to identify the sources of mercury in wet deposition he measured near Steubenville, Ohio. Dr. Keeler admitted during questioning that receptor models cannot be used to make future predictions. *See, e.g.*, Hearing Transcript at 204 (June 15, 2006). Thus, Dr. Keeler's work cannot answer the critical question of how mercury deposition changes at a given location because of the implementation of CAMR or for that matter IEPA's proposed rule.

The only presentation in the record that attempts to predict the future mercury deposition that will result from various regulatory approaches is that offered by Krish Vijayaraghavan on behalf of Dynegy and Midwest Generating. Exhibit 126. That work shows that the full implementation in 2020 of CAIR and CAMR will lead to less mercury deposition in Illinois than the implementation of IEPA's proposed rule, except for three grid cells where increases in mercury deposition of less than 3% are predicted. *Id.* Thus, adding EPA's CAMR model rule to the IEPA's proposed rule would not produce mercury "hot spots" in Illinois, in fact, it would probably reduce mercury deposition in the state.

For all these reasons, the proposed rule should be revised to include the CAMR model trading rule.

III. IEPA'S RULE HAS NOT CONSIDERED THE SIGNIFICANT COMPLIANCE ISSUES THAT WILL ARISE IF ADOPTED AS PROPOSED.

Currently, there are many questions about EPA's mercury monitoring requirements and whether available continuous emissions monitoring systems (CEMS) can accurately measure mercury emissions, particularly at the levels necessary to demonstrate compliance. Exhibit 132; *see, e.g.*, Mr. McRanie, Hearing Transcript at 1692 (August 22, 2006). As discussed at the hearing by Mr. McRanie, there are serious doubts whether the currently available CEMS can accurately monitor at the level required to show compliance with CAMR, much less the more stringent Illinois proposed rule. *See, e.g.*, Mr. McRanie, Hearing Transcript at 1753-54 (August 22, 2006). Imposing a more stringent limit only exacerbates those concerns. *See* Mr. Romaine, Hearing Transcript at 227 (June 19, 2006) (concurring that for a standard equal to 0.8 $\mu g/m^3$ and a CEMS with an accuracy of plus or minus one $\mu g/m^3$ it would be impossible to determine compliance with the standard as a practical matter).

Additionally, EPA's mercury monitoring requirements are currently being challenged in the D.C. Circuit. It remains to be seen whether that challenge will lead to revisions to EPA's monitoring requirements but it is likely that some changes will be made by EPA. The proposed regulations incorporate some EPA requirements by reference but they also include specific mercury monitoring requirements. Prairie State recommends that Illinois simply incorporate the EPA's monitoring requirements by reference. This will avoid a situation where monitoring requirements in Illinois are inconsistent with the remainder of the country leading to the potential unavailability of CEMS for facilities in Illinois.

As explained by Mr. Roberson in the attached assessment of mercury CEMS for Prairie State (Attachment 3), mercury CEMS continue to be a work in progress. They continue to have technical difficulties including: the sampling probe, transporting the sample long distances, reliable and affordable calibration standards, and the lack of an instrumental reference method (IRM) for mercury. While mercury CEMS will continue to improve, it is important that their current limitations be considered in this rulemaking.

IV. A TECHNOLOGY BASED STANDARD MUST BE ADOPTED IF IPCB STANDARDS ARE MORE STRINGENT THAN CAMR.

A. Technology Based Standard (TBS) is needed to address potential shortfalls in technology.

There was substantial testimony during the hearings regarding the capabilities of technology to reduce mercury emissions to the levels required by the proposed rule. One theme that was heard throughout is the lack of long-term data. That short-coming is why a technology-based standard is needed to bridge the gap between what technologies are capable of achieving by 2009 versus 2018. While the short-term tests may be promising, they are not sufficient to conclude that levels required by the proposed rule can be sustained day in and day out over the life of the facility. As noted above, those ACI tests cannot even be said to be promising for high sulfur bituminous coal, such as Illinois coal.

The utility industry will undoubtedly rise to the challenge and build a better mousetrap to meet the requirements as it has done in the past (e.g., SCR for NO_x), assuming those requirements are physically achievable. The real question is timing. EPA took this into account in establishing the timing for CAMR; IEPA did not. A rule requiring compliance in 2009 will necessarily have to be based on technology available today given the time necessary to procure and install the technology and to get the necessary permits in place. If that technology proves incapable of achieving the levels required, a facility will have no option other than to shut down absent a technology based standard as the proposed rule does not allow trading to make up for any shortfall in the technology.

If IEPA is correct in its view that the technologies are capable of achieving 90% removal, adopting a technology-based standard poses little impact as it would never need to be used. However, if IEPA is incorrect, which Prairie State believes based on its investigation into the capabilities of technology for its new units, without a technology based standard, facilities would be required to shutdown, greatly curtail operations, or face enforcement actions as they would have no way to comply with the requirements. A technology-based standard would alleviate this concern and would also bridge the gap pending the outcome of ongoing DOE studies. Moreover, IEPA's technology expert, Dr. Staudt, has indicated he supports the inclusion of a technology-based standard. Dr. Staudt, Hearing Transcript at 87 (June 22, 2006).

B. The proposed TTBS is not sufficient.

Prairie State is pleased that IEPA has proposed a temporary technology-based standard ("TTBS") for the reasons discussed above. However, the TTBS proposed by IEPA needs improvement.

First, eligibility should not be tied to the use a particular sorbent (halogenated activated carbon). This linkage is too restrictive and ignores new reagents and technologies that are being developed that may be as or more effective than halogenated activated carbon. Moreover, the preliminary data on high sulfur coal indicates that halogenated activated carbon may be less effective than other activated carbons. Exhibit 80, Attachment 3. The rule should not require an EGU to go through an alternative process to use other sorbents. Instead, the rule should indicate that any sorbent approved by the Agency may be used. This would afford the Agency the ability to consider and approve the use of other products as they become available and are proven effective without having to modify the rule or require an EGU to go through the alternative process. To implement this concept, Prairie State recommends replacing "halogenated activated carbon" with **"sorbent or reagent approved by IEPA."**

Second, the TTBS should allow an optimization study to determine the optimum injection rate such as the one included in Prairie State's construction permit. Prairie State's permit includes detailed provisions for determining the optimum rate of sorbent injection (Attachment 4). Those provisions consider all of the variables that affect mercury removal (e.g., halogen, sulfur and mercury content of the coal; SCR catalyst type and quantity; temperature of the flue gas passing through the air preheater; type of particulate collection device; installation of additional downstream control devices such as a wet electrostatic precipitator). It is unclear whether the proposed TTBS considered such variables in arriving at the default injection rates.

The provisions in Prairie State's permit should be acceptable as an alternative to the default rates included in the proposed TTBS without the need for further permitting activities. For new facilities like Prairie State whose construction permit already includes a provision regarding mercury control and the use of a sorbent, the TTBS should not require a new or revised operating permit as indicated in § 225.238(b)(2) and § 225.238(d). A new source should be allowed to indicate in its initial Title V application that it is applying to operate under the TTBS in accordance with its construction permit. A new facility that incorporated provisions regarding mercury control should not have to go through duplicative review and public participation when those provisions have already been subject to such requirements. Prairie State has a similar concern with respect to proposed § 225.238(e)(1)(C).

There is a significant cost associated with the default injection rate. As indicated in Prairie State's testimony, the cost for compliance with the TTBS at the designated injection rate of activated carbon is $25 million per year just for the activated carbon itself. That cost is based on a cost of $1 per pound of activated carbon (Sid Nelson, Hearing Transcript at 116 (June 21, 2006 am) times 10 pounds per actual cubic foot (acf) of flue gas times the Prairie State flue gas flow of 2,700,000 acfm per unit. This high cost is not justifiable as there is currently no evidence that supports an injection rate of 10 lb/million acf.

Third, Prairie State recommends that a provision similar to § 225.234(b)(2)(D), which allows existing units to lower the injection rate if particulate matter emissions are adversely impacted, be included in § 225.238 for new EGUs. While new units should not have the same particulate control device size concerns as discussed at the hearing, they nevertheless may experience unforeseen problems given the lack of long-term experience with how activated carbon will impact facility operations. Prairie State also recommends that "safety issues" be added as a basis for allowing the injection rate to be lowered. For example, as discussed at the hearing, Presque Isle recently had a fire in their TOXECON baghouse due to overheating the carbon in the baghouse. Dr. Staudt, Hearing Transcript at 91 (June 21, 2006 pm).

Fourth, Prairie State does not understand the requirement, as proposed in § 225.238(c)(2)(A), to record the activated carbon feed rate on an hourly average basis. There does not appear to be any rational basis for requiring a facility to average its activated feed rate hourly. As the mercury content of the coal cannot feasibly be monitored and recorded on an hourly average basis, knowing the injection rate on an hourly basis will provide no useful information with respect to the facility's mercury control effectiveness.

Finally, there are some potential timing issues in the proposed TTBS that need to be worked out. Under § 225.237 of the proposed rule, compliance with the mercury standard commences on the date of the initial performance test. Application to use the TTBS must be made at least three months before compliance with § 225.237 would have to be demonstrated and has to be included in a Title V permit application. The initial Title V application, however, is due within one year of commencing operation. Theoretically, a facility would need to submit a Title V permit application to comply with the TTBS three months after initial startup and before the compliance period is complete. It is Prairie State's understanding based on Mr. Romaine's testimony at the hearing that a Title V permit application would not have to be submitted prematurely. Mr. Romaine, Hearing Transcript at 259-60 (June 20, 2006). Prairie State recommends the rule be clarified on this point.

Prairie State is providing a markup of the proposed TTBS with its recommended changes (Attachment 5.

C. The Proposed Multi-Pollutant Standard Could Negatively Impact New Sources

In addition to the TTBS, IEPA in conjunction with certain utilities has proposed a multi-pollutant standard (MPS) that addresses sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions in addition to mercury. While the proposal is directed towards existing facilities, it may have serious consequences on new facilities within the state. The primary concern for new facilities with the proposed MPS is the effect it will have on the availability of SO_2 allowances for new units. As proposed, existing units must relinquish their allocated unused allowances as a result of the MPS to IEPA, who in turn will retire them. If the majority of existing units elect to sign up for the MPS, it will reduce the pool of available allowances making it difficult, if not impossible, for Prairie State or any other new unit to purchase allowances for its emissions. There is a potential solution. To alleviate potential shortfalls in the availability of allowances, IEPA should make the allowances relinquished to it under the MPS available to new units for purchase.

V. CHANGES TO THE PROPOSED RULE ARE NECESSARY IF IPCB ELECTS TO GO BEYOND CAMR.

While inclusion of the TTBS revised as suggested will address most of the concerns Prairie State has with the proposed rule, a few issues remain.

First, Prairie State recommends that ASTM D6722-01 "Standard Test Method for Total Mercury in Coal and Combustion Residues by Direct Combustion Analysis" to determine mercury in coal be added to § 225.140 and § 225.202 of the proposed rule as an acceptable method. ASTM has obtained EPA acceptance of ASTM D6722-01 as equivalent to all other required mercury determination methods. Per ASTM, this acceptance is so stated in the Federal Register Volume 70 Number 209 (October 31, 2005) (40 C.F.R. Part 63).

Second, compliance should be judged at the unit level, not on a both unit level and source level as specified in § 225.210(e) of the proposed rule. If each EGU must meet the stack limit, then it follows that the source should be in compliance. By requiring both the unit and source to be in compliance, Illinois is effectively assessing two violations if a unit fails to meet the emission limit. Proposed provision § 225.230(d)(3) also could result in multiple violations when only one unit may be having compliance issues.

Finally, averaging provisions should be provided for both “existing” and “new” units. Section 225.232 appears to apply only to “existing” units. “New” units should also have averaging provisions since the stringency of the limits Illinois proposes to impose on new units is the same as existing units -- 90% control.

CERTIFICATE OF SERVICE

I, Mary Frontczak, certify that I served electronically the attached POST-HEARING COMMENTS upon the following this 20th day of September, 2006:.

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and electronically to the persons listed on the **ATTACHED SERVICE LIST**.

_[s] Mary Frontczak___________________

DATED: September 20, 2006

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EXCERPTS FROM THE
ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT between PRAIRIE STATE MANAGEMENT COMPANY, LLC (PSMC)
and
(Contractor)
dated as of [October 31], 2005

8.1.1.7 Environmental Compliance Guarantee. Contractor guarantees that each Unit and the Facility shall comply with all requirements of the Permits during the entirety of the Performance Tests including the Facility Reliability Test (the "Environmental Compliance Guarantee"). Contractor further guarantees that each Unit and the Facility shall meet the Environmental Compliance Guarantee at the loads with the fuels specified in Appendices C and E. A description of certain Permit levels that adjust over time that are required to be achieved to satisfy the Performance Guarantees are set forth in Appendix E. Article 16

LIMITATIONS OF LIABILITY

16.1 Aggregate Limitation of Contractor's Liability.

- 16.1.1 To the fullest extent permitted by law, the total cumulative monetary liability of Contractor for payments in respect of Contractor's failure to cause Mechanical Completion to occur or failure to cause the Facility to achieve the Environmental Compliance Guarantee or to achieve the Minimum Performance Guarantees or for violations of Applicable Legal Requirements by Contractor, its Affiliates, Subcontractors or Personnel shall not exceed an amount equal to the Contract Price; provided, however, that (i) the foregoing limitation shall not limit Contractor's liability arising out of any Claims for which Contractor has an indemnification obligation under this Agreement, and (ii) the aggregate amount of Contractor's liability under this Agreement shall not be reduced by any proceeds of the insurance described in **Appendix Q** that are received by Contractor or paid to PSMC or any Owner.

5.1 Contract Price. As full consideration for the full and complete performance of the Work by Contractor and Contractor's other obligations hereunder and all costs incurred in connection therewith, PSMC shall, subject to **Sections 5.2** and **5.3**, pay to Contractor the firm fixed lump sum amount of $__,___,___,___.__, inclusive of all Contractor Taxes (the **"Contract Price"**)

2.2 Work to be Performed. Except as otherwise expressly set forth in **Article 3** as being the responsibility of PSMC, Contractor shall, in accordance with the Agreement, perform or cause to be performed all acts or actions required or necessary in connection with the design, engineering, permitting (with respect to Contractor Permits), procurement, equipping, supplying, manufacturing, construction, installation, training, commissioning, start-up, demonstration, testing, operation, care, custody and control, and completion of the Facility (whether at the Facility Site or elsewhere) until Final Completion and satisfaction of Contractor's warranty obligations during the Warranty Period (collectively, the **"Work"**) all on a lump sum, turnkey, basis and in accordance with this Agreement.

APPENDIX E –FUNCTIONAL TESTS; PERFORMANCE TESTING

SECTION 05100 – BASIC REQUIREMENTS

1.09 ENVIRONMENTAL COMPLIANCE TESTS:

A. Emissions tests and removal efficiency tests for Unit air emissions shall be conducted as specified in the Final Air Permit issued by the State of Illinois.
Contractor shall demonstrate compliance with the Final Air Permit by meeting the requirements in such Final Air Permit not later than 60 days after achieving 90% of maximum production rate or 180 days after first fire, whichever comes first unless such time periods are extended by a wavier issued by the state of Illinois.

B. Emissions tests and removal efficiency tests for air emissions from Unit auxiliary equipment shall be conducted as specified in the Final Air Permit.

C. During these tests the coal, reagent, and make-up water will be maintained within the ranges specified in Appendix C.

D. As a condition of Substantial Completion, the emission requirements of the Final Air Permit and the following requirements shall be met for each Unit:

Table 1.09D

	lb/mmBtu	lbs/hour	Other	Remarks
SO2	0.182		98% Removal	Note 2 and 3
NOX	0.07			Note 2
PM/PM10 Filterable	0.015			
PM10 Total	0.035			Note 5
CO	0.12			Note 2
VOM	0.004			
Sulfuric Acid Mist	0.005			
Hydrogen Fluoride	0.00026			
Lead		0.0678		
Mercury		0.016	$21x10^{-6}$ lb/MWHr	Note 2 and 4
Beryllium		0.0085		
Hydrogen Chloride		24.4		
Opacity			20% - 6 minute average	Note 2

Table 1.09D				
	lb/mmBtu	lbs/hour	Other	Remarks
Ammonia Slip			2 ppm average	
Notes:				
1. Testing shall be in accordance with the Final Air Permit, Sections 2.1.8, 2.1.9-1, and 2.1.9-2.				
2. Emissions shall be determined using the certified plant CEM on a continuous basis throughout the test period.				
3. For SO2, both the emission limit and the removal efficiency must be satisfied.				
4. For Mercury, both of the emission limits must be satisfied.				
5. The AQCS must be designed on the basis of 0.018 lb/mmBtu PM10 (total) emission rate. Design documents supporting this requirement shall be provided.				

E. As a condition of Final Completion, the following requirements shall be met for each Unit subsequent to Substantial Completion, determined based on CEM data and fuel sampling in accordance with this Appendix E:
   1. For SO_2, emissions for all operations, including start-ups, shutdowns and malfunctions, shall not exceed (i) 0.182 lbs/mmBtu, 30 day rolling average, and (ii) 2,450 lbs/hour, daily average, and (iii) in no event shall the average SO_2 removal efficiency for the period subsequent to Substantial Completion be less than 98%.
   2. For NOx, emissions for all operations, including start-ups, shutdowns and malfunctions, shall not exceed 0.07 lbs/mmBtu, 30 day rolling average; and emissions for all operations, excluding start-ups, shutdowns and malfunctions, shall not exceed 893 lbs/hour, 24 hour average.
   3. For CO, emissions for all operations, excluding start-ups, shutdowns and malfunctions, shall not exceed 0.12 lbs/mmBtu, 24 hour average; and emissions for all operations, including start-ups, shutdowns and malfunctions, shall not exceed 893 lbs/hour, 24 hour average.
   4. For Mercury, emissions for all operations, excluding start-ups, shutdowns and malfunctions, shall not exceed (i) 0.016 lbs/hour, 3 hour average, and (ii) $21x10^{-6}$ lbs/MWHr, for the period subsequent to Substantial Completion.
   5. For opacity, the particulate matter emissions shall not exceed 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

F. As a condition of Final Completion, average ammonia slip measured at the outlet of the SCR catalyst shall not exceed 2 ppm for the period subsequent to Substantial Completion.

G. Emissions tests for Facility wastewater shall be conducted as specified in the applicable Permits.
   1. Monitoring of Facility wastewater shall be concurrent with all Performance Test to verify compliance with the Permits.
   2. The wastewater monitoring shall be conducted in accordance with the requirements of the Permits. If monitoring is conducted at more frequent intervals, this data shall also be provided.

EPA REGION 6 COMMENTS ON NMED CAMR PROPOSAL

Regulatory Comments:

20.2.85.2 – Should the scope be changed to apply to only coal-fired electric generating units?

20.2.85.50 - What is meant by the effective date being Nov. 17, 2006? Is this date the date EGUs need to begin complying with the rules, or just the approximate date that NMED expects the rule to be final?

20.2.85.7 - A definition you may want to include is "sequential use of energy" to deal with the potential for a future cogeneration units being constructed in New Mexico. We also encourage NMED to adopt the June 9, 2006 definition of "electric generating unit" to include the exclusionary language on solid waste incineration units in the definition of electric generating units. Other definitions that should be considered for adoption include continuous emission monitoring system (CEMS), control period, emissions, excess emissions, mercury budget permit.

20.2.85.101 A. - We suggest that you add a calendar year reference to the last sentence of the paragraph......."No electric generating unit regulated under this part shall emit a quantity of mercury greater than the number of annual mercury allowances the electric generating unit has been allocated under 20.2.85.103 NMAC beginning in calendar year 2010."

20.2.85.101 B. - We suggest that you also show the state's budget in ounces for the corresponding budget years.

20.2.85.102 - We do not believe this paragraph is needed in the rule. If the State finalizes a rule with "no trading" provisions, the State is basically creating a State run program that differs from EPA's regulatory approach. Therefore, it will actually be up to New Mexico to ensure and demonstrate to EPA that you have met your State budget versus the utilities demonstrating to EPA that they have met the allowance provided to them by the State since they are not participants in the Federal cap-and-trade system.

20.2.85.103 – EPA has several questions/comments:

1. Since New Mexico is considering a no-trading type program, has New Mexico considered a larger new unit set aside in the event that new units are built in future years, or would New Mexico redistribute the utilities mercury allowances to accommodate a new unit?
2. Were lower allowance levels considered for the existing units to provide a buffer for New Mexico to stay within its State mercury budget?

3. How will NM address the possibility of an electric generating unit exceeding its allocation of allowances? Will an enforcement action result? EPA is concerned about the possible implications of a State with a no-trading approach exceeding its State budget and the State should clearly demonstrate in its Section 111(d) plan what safeguards are in place to prevent the State from exceeding its assigned State budget.

4. What if a utility exceeds its allowance, what type of penalty and enforceable restoration to the State's allowance and budget system will be made? Any potential restoration requirements need to be incorporated into an enforceable permit for the unit.

20.2.85.104 - Would higher fees for mercury allowances provide a disincentive to electric generating units to exceed its allocation of allowances? Has some type of escalating fee system been considered based upon the number of allowances needed by an EGU?

20.2.85.105 - What is the process for new units to request and receive allowances from NMED? What if there are not enough allowances available for the new source to start operation? We are concerned about the implications for both existing and new units if there are not sufficient allowances for a new unit to start operation in New Mexico, or the potential for an existing unit's NMED assigned allocation of allowances to be impacted without sufficient time to install any necessary pollution controls to make room for a new unit's emissions.

20.2.85.106 - We suggest revising the regulatory text to state: "Sources subject to this part are required to comply with all requirements of 40 CFR Part 75 concerning determinations of mercury mass emissions."

General Comments:

- A provision requiring compliance with 60.4170(a), (b), (c), (d) is needed in the regulations. Please note that CEMS units for existing units need to be certified by January 1, 2009. There needs to be a definitive requirement in the State rules for monitoring and reporting by the units.

- There are no CAMR permit requirements in the regulatory language. The State should clearly outline the CAMR permit requirements in the regulatory text. Does the State intend for these rules to function as a permit-by-rule type program?

- Will NMED specify that the companies or operators that own the San Juan power station or Escalante power stations designate an individual as mercury designated representative to report to NMED.

- NMED should outline in the regulatory proposal what the EGUs will need to provide NMED to demonstrate an increment of progress as discussed at 60.21

and 60.24(e). NMED will need to ensure that it's section 111(d) submittal satisfies the requirements of 40 CFR part 60 – Subpart B.

STATUS OF MERCURY CONTINUOUS EMISSION MONITORING SYSTEMS

September 2006

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REGULATORY BACKGROUND

On May 18, 2005, EPA published in the Federal Register the Clean Air Mercury Rule (CAMR) designed to reduce mercury emissions from coal-fired electric generating units (EGUs). CAMR creates a cap-and-trade program that will be implemented in two phases. Phase 1 caps mercury emissions at 38 tons per year (tpy) in 2010 and phase 2 caps mercury emissions at 15 tpy in 2018. CAMR requires existing units to begin to continuously monitor mercury emissions with a certified system no later than January 1, 2009. CAMR recognizes two options for obtaining continuous mercury emission data: (1) sorbent trap monitoring systems and (2) mercury continuous emission monitoring systems (CEMS).

EPA developed CAMR pursuant to the Agency's authority under section 111(d) of the Clean Air Act (CAA). Section 111(d) authorizes EPA to promulgate standards of performance that States must adopt through the State Plans, which requires State rulemaking action followed by review by EPA. If a State fails to submit a satisfactory plan, EPA has authority to prescribe a plan for the State. States are not required to adopt and implement EPA's proposed mercury emission trading rule, but States are required to be in compliance with their statewide mercury emission budgets.

The State of Illinois has proposed to opt out of the federal trading program and instead impose unit/facility specific mercury emission limits or percent mercury removal requirements. Specifically, the Illinois Environmental Protection Agency (IEPA) has proposed to add new regulations to 35 Illinois Administrative Code Part 225, Control of Emissions from Large Combustion Sources. These regulations would control mercury emissions from coal-fired EGUs located in the state. Beginning July 1, 2009, the regulations would require existing EGUs to meet either (1) an emission limit of 0.0080 lb Hg/GWh gross electrical output, or (2) achieve a 90 percent reduction of input mercury.[1]

MERCURY MONITORING ISSUES

Mercury CEMS continue to be plagued by slower than expected development and a limited number of viable suppliers. The potential limited number of mercury CEMS suppliers tends to make the electric utility industry want to start the procurement process sooner rather than later. On the other hand, reports of continued technical difficulties with mercury CEMS cause the utility industry to want to proceed cautiously. Significant technical issues include: the sampling probe, transporting the sample long distances, reliable and affordable calibration standards, and the lack of an instrumental reference method (IRM) for mercury. Each of these technical issues is discussed in more detail below. Moreover, the Illinois proposed mercury EGU rule presents mercury monitoring challenges above and beyond those posed by EPA's CAMR. Illinois-specific issues are also discussed below.

[1] For the purpose of this rule, *existing* EGUs are those in commercial operation on or before December 31, 2008. Also, *input mercury* means the mass of mercury that is contained in the coal.

Sampling Probes

Most of the leading Hg CEMS vendors use an inertial dilution probe. These probe assemblies are bulky and quite complicated. To illustrate the point, a schematic of a typical inertial sampling probe is shown in Figure 1.[2]

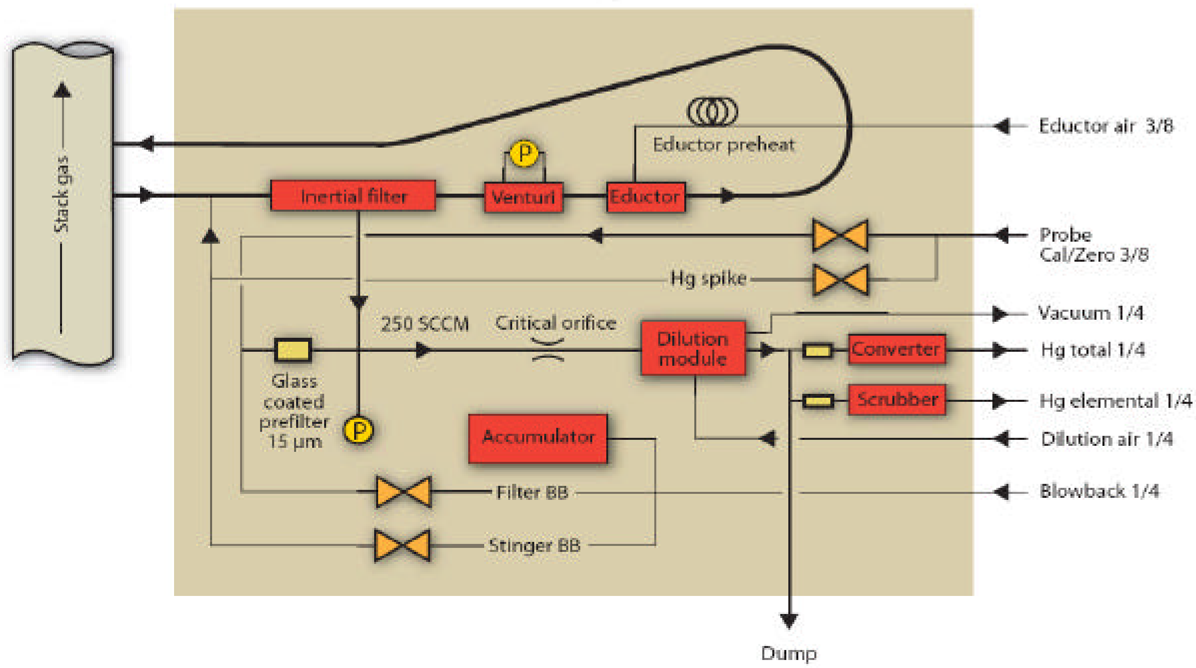

Figure 1
Thermo Electron Inertial Mercury Probe

Dilution helps minimize the deleterious effects of acid gases and selenium on analyzer components, especially catalytic converter systems. Dilution sampling also means the sample will be analyzed on a wet basis, which means the Hg concentration can be simply (without need for moisture correction) multiplied times stack volumetric flow rate to yield Hg mass emissions (ounces per hour). However, these probes have been especially problematic on wet stacks (e.g., units with wet flue gas desulfurization systems) and appear to be the root cause of poor reliability. The dilution probes withdraw a relative large volume of gas from the stack, albeit only a small sub-sample is ultimately delivered to the analyzer. However, when the water from the saturated flue gas is evaporated by the probe heat, scrubber solids tend to get deposited in critical openings and bends. Also, the dilution probe's inertial filter has also proven, at times, to be a challenge to get the calibration gases through. This problem appears to be mitigated by humidifying the calibration gas prior to injection.

[2] Figure 1 is reproduced from a Thermo Electron brochure. The probe box is 10.5 inches wide x 18.5 inches high x approximately 3 feet in length and weighs about 80 pounds. The fractions (i.e., 1/4 and 3/8) on the figure denote the respective tube diameters (inches).

Calibration Standards

Two forms of gas are needed for the calibration of Hg CEMS: elemental (Hg^0) and oxidized (Hg^{+2}) mercury. The calibration gases can be generated on site for both species of mercury (Hg^0 and Hg^{+2}), or supplied in compressed gas cylinders (only Hg^0). EPA's Part 75 rule requires affected sources to use both Hg^0 and Hg^{+2} standards, which must be NIST traceable.[3] To date, no such NIST traceable standards exist or can be purchased. We understand from discussions with EPA staff that NIST is close to having a protocol available to use for characterizing vendors' gas generators or gas cylinders. Perhaps by the end of 2006, vendors will have NIST research grade materials (RGMs) for Hg^0. Vendors would then follow a yet-to-be-developed EPA protocol, using the RGMs, to mass produce either Hg gas generators or Hg calibration gas cylinders.

RMB's experience with Hg^0 gas cylinders has not been good. First, Hg^0 cylinder gas is very expensive relative to the cost of SO_2 and NO_x cylinder gases. Second, the cylinders do not last as long as the SO_2 and NO_x calibration gases, apparently because of the large calibration gas volumes required to "flood the probe" for each calibration cycle. Lastly, we have actually experienced a change in concentration during the life of a cylinder. We believe that during one cold December night a bit of the Hg apparently condensed, lowering the effective Hg gas-phase concentration in the cylinder. Once the cylinder returned to a more normal temperature, the condensed Hg evaporated and, in effect, increased the cylinder concentration above the "certified" value. For these reasons, RMB has stopped purchasing Hg cylinder gases for our Hg CEMS Demonstration projects. The foundation of any successful CEMS program has always been the availability of reliable and accurate calibration standards; thus, there is need for considerable improvement in Hg calibration materials

The chemical properties of Hg^{+2} compounds preclude them from being compressed into gases. Thus, Hg^{+2} gas cylinders cannot be manufactured. HoVaCal and MerCal gas generators can produce $HgCl_2$ (oxidized Hg) gas. EPA and NIST are purportedly working on a traceability protocol and ways to characterize the uncertainty for oxidized mercury gas generators. Unfortunately, in the previously referenced conversation with EPA, Agency personnel acknowledged that NIST is far behind schedule in developing RGMs for Hg^{+2}. To date, we believe only the HoVaCal device has been used in the field for Hg^{+2}. The HoVaCal principal of operation is based on using a high temperature evaporator (see Figure 2) to convert a liquid $HgCl_2$ solution into a gas-phase mixture with nitrogen carrier gas. Using the HoVaCal is a manual, labor-intensive process and requires considerable analytical chemistry skills because the accuracy with which the liquid solutions are prepared basically control the accuracy of the calibration standards.

[3] See, for example, 40 C.F.R. §75.20(c) and Appendix A, §5.1.9.

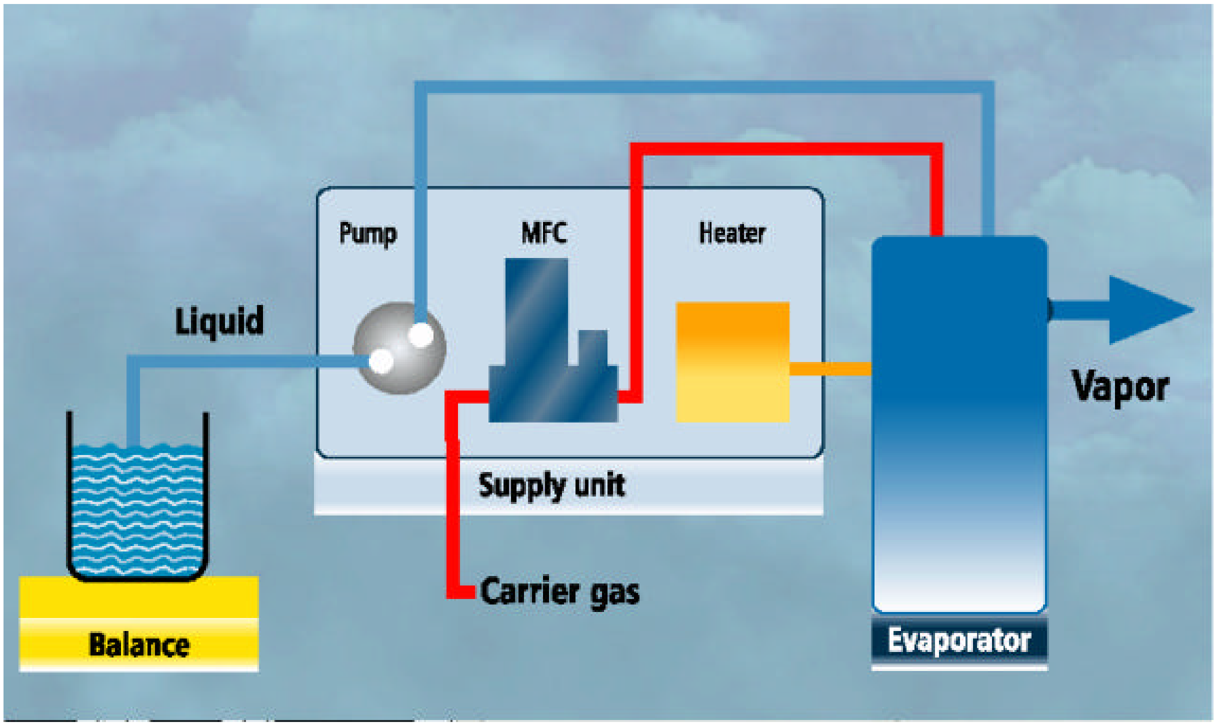

Figure 2
Schematic of HoVaCal Illustrating Principles of Operation

Sample Transport

This remains an area of uncertainty. At one of the EPA mercury CEMS evaluation sites, the analyzers are located in a trailer, but the sample transport distance is less than 150 feet. At a second mercury CEMS evaluation site, all the analyzers are located at the sampling elevation, which is over 400 feet above grade. Unfortunately, most stack sampling locations are +300 feet above grade but, unlike the second evaluation site, do not have adequate space to accommodate a mercury CEMS. So, the questions are: can mercury be transported in excess of 300 feet in well-heated (+350º F) sampling lines without losing any Hg, and if so, how maintainable are these high technology sample lines.

Instrumental Reference Method

Historically (and CAMR is no different), EPA requires each installed CEMS to be "certified" before the CEMS is used to collect compliance and/or allowance tracking data. The linchpin of EPA's CEMS certification process is the relative accuracy test audit (RATA). In simplest terms, a RATA describes the process of collecting data with the appropriate EPA reference method and simultaneously collecting data with the CEMS. The relative accuracy of the CEMS is then calculated from the required minimum of nine valid paired runs. Relative accuracy is a statistic designed to provide a measure of the systematic and random errors associated with the data from the CEMS – when compared to the EPA reference method. CAMR specifies the Ontario Hydro Mercury (OHM) method[4] as the mercury reference method and is to be used to conduct a RATA.

The OH method is complicated and expensive to perform. Moreover, a very high level of experience and attention to detail is required to obtain consistent results. In several field studies, EPA contractors have consistently had difficulty achieving the required precision between paired OH runs to be used in the RATA calculations. As stated above, CAMR requires a minimum of nine valid paired runs for each RATA test. EPA contractors have typically conducted 12 paired runs, but once the analysis are completed, find that less than nine runs are valid. But time is the real enemy of the OH method. It has taken as along as 2 months to receive some of EPA's RATA results. Granted, this may not be indicative of the time required for utility companies to receive results given the apparent EPA/EPA contractor bureaucracy. However, RMB expects that many utility companies, which use outside laboratories for OH sample analysis, will find that 3 to 4 weeks are required to obtain RATA results.

Clearly, there is a major need for EPA to quickly develop a mercury IRM. Without a mercury IRM, RMB does not believe the electric utility industry has any chance of certifying mercury CEMS in any reasonable timeframe or at any reasonable cost. One of the primary reasons utility companies have experienced high CEMS availability and excellent CEMS accuracy under EPA's Acid Rain program is the advent of instrumental reference methods for SO_2 and NO_x. RATA results are available before the testing contractor leaves the plant. Thus, if there is a problem, corrective action can be taken, and the RATA can be repeated – often without having to reschedule the testing contractor. EPA is just beginning to field test the elaborate procedures specified in the Agency's conceptual IRM. Given the progress made to date, RMB does not believe that EPA's Hg IRM can be promulgated in time for the initial round of Hg CEMS certification tests.

Mercury CEMS Accuracy

While on the subject of RATA testing, there is definitely a problem with EPA's "alternative" acceptance criterion. EPA's alternative RATA criterion is if the mean reference method (RM) concentration is less than 5.0 $\mu g/m^3$, RATA results are acceptable if the absolute value of the mean difference between the RM and CEMS values does not exceed 1.0 $\mu g/m^3$.[5] While the alternative criterion may be reasonable when the mean RM concentration is around 5 $\mu g/m^3$, it does not seem appropriate when the mean RM concentration is say, 1 $\mu g/m^3$. In this example, the potential error is effectively ±100 percent of the RM-determined emission concentration. We believe the alternative criterion is important, but probably too lenient in its current form. The major question is how much this "loophole" can be tightened while remaining reasonably achievable.

[4] The Ontario Hydro Mercury method is codified as ASTM D6784-02.

[5] 40 C.F.R., Part 75, Appendix B, Figure 2.

SPECIAL CHALLENGES POSED BY ILLINOIS MERCURY PROPOSAL

States, such as Illinois, who are proposing mercury emission standards more aggressive than CAMR are making unsupported assumptions with respect to the status of continuous mercury monitoring technology. These States apparently assume that if mercury monitoring technology is advanced enough to support EPA's cap-and-trade program, then it is sufficient for their more aggressive command-and-control regulations. There are at least two problems with this assumption. First, EPA is not contending that Hg CEMS technology is 100 percent ready for CAMR. For example, consider the following quote from a recent EPA report.[6]

> *It is apparent through the results from each subsequent field evaluation that the reliability and accuracy of Hg CEMS continues to improve. However, some issues such as probe and umbilical operation continue to affect the reliability of CEMS systems on wet stacks.*

The Illinois proposed mercury rule will be impacted by the alternative RATA criterion discussed above. RMB examined the mercury content of both eastern bituminous and western subbituminous coals, and we observed nominal uncontrolled Hg emission concentrations in the range of 6-10 micrograms per dry standard cubic meter (µg/dscm). Therefore, when 90% reduction is applied as suggested by the Illinois proposed mercury rule, the expected stack concentration will be in the 0.6-1.0 µg/dscm range. The Illinois proposed alternative Hg emission limit of 0.0080 lb Hg/GWh gross electrical output is (assuming a gross heat rate of approximately 9,500 Btu/kW-hr) equivalent to 0.84 lb/10^{12} Btu. For coal-fired boilers, 0.84 lb/10^{12} Btu converts to a flue gas concentration of approximately 0.81 microgram per wet standard cubic meter (µg/wscm). It is important to convert the proposed Illinois Hg limit to concentration units because many important Part 75 monitoring criteria are expressed in the units of µg/dscm. For example, if stack gas Hg concentration is less than 5 µg/dscm during a RATA, the continuous Hg monitoring system achieves EPA's alterative RATA criterion if the mean difference between the reference method and the monitor is ± 1µg/dscm. The Part 75 specification for daily calibration error checks is 5 percent of span or ± 1µg/dscm. In other words, Part 75 permissible Hg monitoring tolerances are on the order of 1.23 (i.e., 0.81 x 1.23 = 1.0) times Illinois' proposed Hg limit. Thus, the uncertainty of Hg measurements at the Illinois proposed levels is, and is expected to remain, quite large. Although the proposed Hg emission limitation is a few years away, it is too soon for IEPA to begin thinking about developing an enforcement discretion policy, considering the likely uncertainty in the Hg monitoring data at these very low concentrations. There is very little experience in measuring mercury emissions at these low levels. There is a very real question whether such low mercury concentrations can be measured <u>reliably</u>, <u>accurately</u> and <u>precisely</u>.

A second problem, which has already been alluded to, is that stringent Illinois Hg limit can result in much lower and more difficult to measure Hg concentrations than will CAMR. EPA's Part 75 monitoring requirements were designed for the SO_2 cap and trade program and as such includes components such as missing data substitution, which are needed to accurately track emissions during all operating hours. Some of those components may not be appropriate for tracking

[6] "Mercury Emissions Monitoring Program for Coal-Fired Boilers under the Clean Air Mercury Rule Status Report," U.S. Environmental Protection Agency, Clean Air Markets Division, Washington, DC, February 2006.

compliance with the Illinois proposed Hg emission rate limit. In particular, the missing data substitution procedures implicit in the Illinois proposed rule are very problematic from two different perspectives. First, although EPA's Part 75 missing data procedures have worked well to maintain high levels of SO_2 and NO_x data availability, Hg CEMS technology is not as mature as are those technologies. We expect that there will be much more missing data with the Hg monitors and, as a result, that the punitive penalties for data substitution will be used more often. Second, under an emission trading program, if a facility is plagued with significant missing CEMS data, which produces emission estimates that are biased high, the facility can enter the market and purchase additional allowances to offset the over-reporting. However, there are no such alternatives with the Illinois proposed Hg emission standards. Moreover, EPA specifically excludes substituted data for determining compliance with emission limits.[7] Therefore, we strongly recommend that the IEPA develop compliance calculations that do not include substituted data.

As previously discussed, as of today, there are no NIST traceable gas standards at all for mercury and not likely to be any at the low levels contemplated by the Illinois proposed rule. The only NIST traceable standards that are available are liquid standards in the oxidized mercury form, and a special device (i.e., HoVaCal) is needed to use those standards on gas analyzers. In addition, EPA's current reference method for mercury (i.e., OHM Method) was not developed to measure these low concentrations, and the method's performance (e.g., precision, accuracy, and bias) has never been evaluated at concentrations below approximately 3 µg/dscm. In short, there are numerous issues associated with measuring mercury in the range of 1 µg/dscm. As the reader should surmise, mercury CEMS have a ways to go before electric utility users can expect to have reliable and accurate continuous measurement of mercury emissions.

CONCLUSIONS

Hg CEMS technology continues to be a "work in progress." In addition to the EPRI Hg CEMS Demonstration project, a number of utility companies are currently conducting their own field evaluations of Hg CEMS from multiple vendors. Progress in operability is being reported, although it is slow and not without setbacks. RMB is cautiously optimistic that time and market demand will improve the quality and availability of Hg calibration materials. In the meantime, States such as Illinois that are embarking on aggressive Hg emission regulations need to recognize that measurement uncertainties are inherent at these low Hg concentrations. Prevailing political considerations may drive the Hg limits quite low; however, the accuracy of low-level Hg measurements is relatively non-partisan.

[7] See, for example, §40 C.F.R. 60.49a(p)(4)(ii) – EPA's Subpart Da emission monitoring provisions for new electric utility steam generating units.

ATTACHMENT 4:

DETERMINING THE SORBENT INJECTION RATE FOR CONTROL OF MERCURY EMISSIONS FROM THE COAL-FIRED BOILERS

1. Purpose

This attachment contains the requirements for the sorbent injection systems for control of mercury emissions from the coal-fired boilers if the boilers are subject to Condition 2.1.2(c)(ii)(A) and the Permittee elects to comply with Permit Option B, i.e., use of a control system for mercury emissions. Among other matters, this attachment defines the process by which the applicable injection rate of sorbent for such systems will be determined. These requirements are included as an attachment to this permit, rather than in the body of the permit, due to the detailed nature of the requirements and the likelihood that these requirements will never take effect, as the emissions of mercury from the coal-fired boiler are subject to requirements adopted by USEPA pursuant to the Clean Air Act.

2. General Requirements

a. The sorbent injection systems, including the selected sorbent(s) shall be designed, constructed and maintained in accordance with good air pollution control practices. For this purpose, sorbent(s) shall be used, such as treated activated carbon, that have been demonstrated to have high levels of effectiveness in similar boiler/control device applications (or pilot tests on an affected boiler). The systems shall have ample capacity to handle and inject such sorbent(s), and the location, number and type of injection ports designed for effective distribution of sorbent in the flue gas. The Permittee shall submit a demonstration to the Illinois EPA showing that the proposed sorbent injection systems meet these criteria, for review and approval by the Illinois EPA.

b. i. The sorbent injection systems shall each be operated to inject sorbent at a rate, in lb/million Btu or lb/scf of flue gas, that is at least at the rate that has been determined to represent the maximum practicable degree of removal for mercury, as previously established pursuant to an evaluation of the effectiveness of the sorbent for control of mercury conducted in accordance with Condition 3 or 4, below. This rate shall be maintained while coal is being fired in the boiler, including periods of startup and shutdown of the boiler.

ii. Notwithstanding the above, for purposes of evaluating the performance of sorbent(s), the Permittee may operate without the sorbent injection system in service or at low rates of sorbent injection as necessary to (1) to prepare for the formal evaluation of a sorbent, i.e., flushing residual sorbent from the boiler and control train, and (2) determine the “performance curve”, provided that the number and duration of such operation is minimized to the extent reasonably necessary for this purpose. (Refer to Paragraph 5(a), below, for the definition of the performance curve.) The Permittee may also conduct pilot tests to confirm suitability of a potential sorbent prior to a detailed evaluation, with prior notification to the Illinois EPA describing such tests and the available data indicating the suitability of the sorbent material for effective control of mercury.

3. Initial Evaluation of the Effectiveness of Sorbent Injection and Establishment of the Optimum Sorbent Injection Rate

a. The Permittee shall perform an evaluation of the effectiveness of injecting sorbent(s) for control of mercury in accordance with a plan submitted to the Illinois EPA for review and comment.

i. The Permittee shall submit the initial plan to the Illinois EPA no later than 180 days after initial start-up of a boiler.

ii. The Permittee shall promptly begin this evaluation after a boiler demonstrates compliance with all applicable short-term emission limits as shown by emission testing and monitoring. At this time, the Permittee shall submit an update to the plan that describes its findings with respect to control of mercury emissions during the shakedown of the boilers, which highlights possible areas of interest for this evaluation.

iii. This evaluation shall be completed and a detailed written report submitted to the Illinois EPA within two years after the initial startup of a boiler. This report shall include proposed injection rate limit(s) for mercury emissions. (See Condition 3(d)(i), below.)

iv. This deadline may be extended by the Illinois EPA for an additional year if the Permittee submits an interim report (1) demonstrating the need for additional data to effectively evaluate sorbent injection and (2) includes an interim limit for mercury injection that provides effective control of mercury.

b. i. If the Permittee is conducting monitoring for mercury emissions with a continuous method, the plan shall provide for systematic review of mercury emissions as related to variation in operation of the boiler, within the normal range of boiler operation, including the effect of (1) boiler load and combustion settings, including excess oxygen, (2) operating data for the SCR system, including the level of uncontrolled NO_x before the SCR, as predicted from boiler operating data, (3) operating data for the scrubber, including pH of the scrubbant, and (4) operating data for the wet WESP. As an alternative to reliance on the measurements from a continuous monitoring system, the Permittee may also supplement its monitoring with semi-continuous monitoring, as provided below.

ii. If the Permittee is conducting monitoring for mercury emissions with a semi-continuous method, the sampling periods shall be of an appropriate duration to cover a representative selection of operation of the boiler.

c. In conjunction with such measurements of mercury emissions, the Permittee shall sample and analyze the fuel supply to the boiler so that representative data for the mercury content of the fuel supply is available that correlates with emission measurements.

d. i. Unless the Permittee elects to conduct a supplementary investigation, as provided below, the maximum practicable degree of removal shall be injection of sorbent at a rate that is twice the rate at the "transition point" from the performance curve. (Refer to Paragraph 5(b), below, for the definition of the transition point.) The sorbent injection systems shall be operated at this rate.

ii. The Permittee may elect to conduct a supplemental investigation of the effectiveness of injection of sorbent(s) to determine whether effective control of mercury, as generally required, is achieved with lower (or higher) injection rates considering the operating rate or other relevant operating parameters of the boilers or control train, excluding periods of startup and shutdown of boilers. For this purpose, the Permittee shall conduct additional measurements and develop additional performance curves for the control of mercury emissions for the boilers under such operating conditions. In the report for the evaluation, the Permittee shall explain why such operating conditions affect the control of mercury emissions, provide the criteria for identification of such operating conditions, and identify the rates at which the sorbent injection system must be operated during such conditions, determined as twice the rate at the "transition point" on the applicable performance curve.

4. Subsequent Evaluation of the Effectiveness of Sorbent Injection and Adjustment of the Optimum Sorbent Injection Rate

a. The Permittee shall repeat the evaluation described in Condition 3, above, in the following circumstances:

i. If the initial evaluation of sorbent injection does not demonstrate that 90 percent or more overall control of mercury will be achieved, a new evaluation shall be commenced two years after the initial evaluation was completed.

ii. If the Permittee undertakes significant changes to the mercury control system, e.g., use of a different sorbent or changes in the location or type of injection ports, at the conclusion of such changes.

iii. If the Permittee undertakes significant changes to other devices in the control train, e.g., use of a different catalyst in the SCR or changes in the chemistry of the scrubber which would generally act to reduce the effectiveness of those devices in controlling or facilitating the control of mercury emissions, at the conclusion of such changes.

iv. If requested by the Illinois EPA for purposes of periodic confirmation of the effectiveness of sorbent injection, which request shall not be made more than once every five years.

v. If the Permittee elects to perform such evaluation, provided, however that the Permittee shall explain why such an evaluation is being undertaken if it is less than two years after completion of the last evaluation.

b. For the purpose of subsequent evaluation, the plan shall be submitted to the Illinois EPA for review and approval at least 45 days before undertaking changes that trigger the need to perform such an evaluation and the evaluation shall be completed in one year, with opportunity for a 6-month extension.

c. As a subsequent evaluation reassesses the continuing operation of the boilers or addresses the future operation of the boilers, the results of the evaluation shall supersede the results of the preceding evaluation and thereafter govern the operation of the sorbent injection systems. For example, if the subsequent evaluation was performed for a new sorbent material and the boilers continue to be operated with such sorbent, operation shall be governed by the results of the subsequent evaluation. If the new sorbent will not continue to be used, operation shall be governed by the results of the preceding evaluation for the sorbent material that will be used.

5. Definition of Terms As Related to Sorbent Injection for Control of Mercury Emissions

For the purpose of these conditions, the following terms shall apply:

a. The "performance curve" is a graphical representation of the effectiveness of a particular sorbent in controlling mercury emissions, comparing the effectiveness of control with increasing rates of sorbent injection.

A performance curve for injection of a particular sorbent material is established by conducting a series of tests under representative operating conditions of the boiler to measure mercury emissions at different rates of sorbent injection (typically starting from zero sorbent to high rates of sorbent injection). For the purpose of presenting data, mercury emissions and sorbent injection rates are expressed in terms of the heat input to the boiler, in million or trillion Btu. This accounts for any differences in the heat input during each test.

In conjunction with these measurements of mercury emissions, the coal supply to the boiler is analyzed for its mercury content. This allows the effect of the sorbent to be expressed in terms of control efficiency, calculated from the mercury emissions and the amount of mercury present in the coal entering the boiler. This also addresses any variation in the mercury content of the coal supply to the boiler, so that another potential cause for variation in emissions is directly accounted for. Otherwise, changes in emissions due to variation in mercury content of coal could not be accounted for and would be incorrectly assumed to be due to changes in the rate of sorbent. The resulting data for the relationship between control efficiency for mercury emissions and the sorbent injection rate is then portrayed in graphical form with a trendline that summarizes this relationship and the performance of the particular sorbent for control of emissions.

b. The "transition point" is the theoretical point where the extensions of two straight lines on the performance curve for a particular sorbent, one representing the initial regime for control of mercury emissions and the other representing the terminal regime for control of emissions, would intersect. Effectively, the transition portion on the performance curve prepared from the evaluation of a particular sorbent is simplified to a single point, the "transition point."

In this regard, the performance curves for control of mercury emissions for different sorbent materials and boilers show a consistent form with two different regimes for control effectiveness, an initial regime and a terminal regime, separated by a transition. In the initial regime, there is a relatively strong effect for control of mercury with injection of sorbent. This appears on the left side of the graph, as the trendline starts from the edge of the graph for the level of control for mercury that is achieved without injection of any sorbent. In the terminal regime, there is a much weaker effect for control of mercury by additional injection of sorbent material. This appears on the right side of the graph, as a nearly flat or flat trendline starting from the left side of the graph. In the transition separating the two regimes, the effect of sorbent injection gradually shifts from one regime to the other. Such transitions on graphs of this form are commonly referred to as "shoulders," given the resemblance to a human shoulder.

Section 225.238 Temporary Technology-Based Standard for New Sources with EGUs

a) General

1) At a source with EGUs that previously had not had any EGUs that commenced commercial operation before January 1, 2009, for an EGU that meets the eligibility criteria in subsection (b) of this Section, as an alternative to compliance with the mercury emission standards in Section 225.237of this Subpart, the owner or operator of the EGU may temporarily comply with the requirements of this Section, through December 31, 2018, as further provided in subsections (c), (d), and (e) of this Section.

2) An EGU that is complying with the emission control requirements of this Subpart by operating under this Section may not be included in a compliance demonstration involving other EGUs at the source during the period that such standard is in effect.

3) The owner or operator of an EGU that is complying with this Subpart by means of this Section is not excused from applicable monitoring, recordkeeping, and reporting requirements in Sections 225.240 through 225.290 of this Subpart.

b) Eligibility

To be eligible to operate an EGU under this Section, the following criteria shall be met for the EGU:

1) The EGU is subject to Best Available Control Technology (BACT) for emissions of sulfur dioxide, nitrogen oxides and particulate matter and is equipped and operated with the air pollution control equipment or systems specified below, as applicable to the category of EGU:

A) For coal-fired boilers, injection of ~~halogenated activated carbon~~**sorbent or other mercury control technique (e.g., reagent) approved by the Agency**.

B) For an EGU firing fuel gas produced by coal gasification, processing of the raw fuel gas prior to combustion for removal of mercury with a system using ~~activated carbon~~**a sorbent or other mercury control technique approved by the Agency**.

2) For an EGU for which injection of ~~halogenated activated carbon~~**a sorbent or other mercury control technique** is required by

subsection (b)(1) of this Section, the owner or operator of the EGU is injecting ~~halogenated activated carbon~~**<u>the sorbent or other mercury control technique</u>** in an optimum manner for control of mercury emissions, which shall include injection of Alstrom, Norit, Sorbent Technologies, or other ~~halogenated activated carbon~~**<u>sorbent or other mercury control technique</u>** that the owner or operator of the EGU shows to have similar or better effectiveness for control of mercury emissions, at least at the following rates, unless other provisions for injection of ~~halogenated activated carbon~~**<u>sorbent or other mercury control technique</u>** are established in a federally enforceable ~~operating~~ permit issued for the EGU, with an injection system designed for effective absorption of mercury. For this purpose, flue gas flow rate shall be determined for the point of sorbent injection**<u> or other mercury control technique</u>** (provided, however, that this flow rate may be assumed to be identical to the stack flow rate if the gas temperatures at the point of injection and the stack are normally within 100º F) or may otherwise be calculated from the stack flow rate, corrected for the difference in gas temperatures.

A) For an EGU firing subbituminous coal, 5.0 pounds per million actual cubic feet.

B) For an EGU firing bituminous coal, 10.0 pounds per million actual cubic feet.

C) For an EGU firing a blend of subbituminous and bituminous coal, a rate that is the weighted average of the above rates, based on the blend of coal being fired.

<u>D) A rate or rates set on a unit-specific basis that are lower than the rate specified above to the extent that the owner or operation of the EGU demonstrates that such rate or rates are needed so that sorbent injection or other mercury control technique would not increase particulate matter emissions or opacity so as to threaten compliance with applicable regulatory requirements for particulate matter or opacity or cause a safety issue.</u>

c) Compliance Requirements

1) Emission Control Requirements

The owner or operator of an EGU that is operating pursuant to this Section shall continue to maintain and operate the EGU to comply with the criteria for eligibility for operation under this Section, except during an evaluation of the current sorbent, alternative sorbents or other techniques to control mercury emissions, as provided by subsection (e) of this Section.

2) Monitoring and Recordkeeping Requirements

In addition to complying with all applicable reporting requirements in Sections 225.240 through 225.290 of this Subpart, the owner or operator of a new EGU operating pursuant to this Section shall also:

A) Monitor ~~activated carbon~~**sorbent** feed rate to the EGU, flue gas temperature at the point of sorbent injection **or other mercury technique**, and exhaust gas flow rate from the EGU, automatically recording this data and the ~~activated carbon~~**sorbent** feed rate, in pounds per million actual cubic feet of exhaust gas at the injection point, on an hourly average.

B) If a blend of bituminous and subbituminous coal is fired in the EGU, records of the amount of each type of coal burned and the required injection rate for injection of ~~halogenated activated carbon~~**sorbent**, on a weekly basis.

C) If a control technique other than sorbent injection is approved by the Agency, monitor appropriate parameter for that control technique as specified by the Agency.

3) Notification and Reporting Requirements

In addition to complying with all applicable reporting requirements in Sections 225.240 through 225.290 of this Subpart, the owner or operator of an EGU operating pursuant to this Section shall also submit the following notifications and reports to the Agency:

A) Written notification prior to the month in which any of the following events will occur: the EGU will no longer be eligible to operate under this Section due to a change in operation; the type of coal fired in the EGU will change; the mercury emission standard with which the owner or operator is attempting to comply for the EGU will change; or operation under this Section will be terminated.

B) Quarterly reports for the recordkeeping and monitoring conducted pursuant to subsection (c)(2) of this Section.

C) Annual reports detailing activities conducted for the EGU to further improve control of mercury emissions, including the measures taken during the past year and activities planned for the current year.

d) Applications to Operate under the Technology-Based Standard

1) Application Deadlines

A) The owner or operator of an EGU that is seeking to operate the EGU under this Section shall submit an application to the Agency no later than three months prior to the date that compliance with Section 225.237 of this Subpart would otherwise have to be demonstrated.

B) Unless the Agency finds that the EGU is not eligible to operate under this Section or that the application for operation under this Section does not meet the requirements of subsection (d)(2) of this Section, the owner or operator of the EGU is authorized to operate the EGU under this Section beginning 60 days after receipt of the application by the Agency.

C) The owner or operator of an EGU operating pursuant to this Section must reapply to operate pursuant to this Section if it is planning a physical change to or a change in the method of operation of the EGU, control equipment or practices for injection of ~~activated carbon~~**sorbent or other mercury control technique** that is expected to reduce the level of control of mercury emissions.

2) Contents of Application

An application to operate pursuant to this Section shall be submitted as an application for a new or revised federally enforceable operating permit for the new EGU and include the following:

A) A formal request to operate pursuant to this Section showing that the EGU is eligible to operate pursuant to this Section and describing the reason for the request, the measures that have been taken for control of mercury emissions, and factors preventing more effective control of mercury emissions from the EGU.

B) The applicable mercury emission standard in Section 225.237 with which the owner or operator of the EGU is attempting to comply and a summary of relevant mercury emission data for the EGU.

C) If a unit-specific rate or rates for ~~carbon~~**<u>sorbent</u>** injection **<u>or other mercury control technique</u>** are proposed pursuant to subsection (b)(2) of this Section, detailed information to support the proposed injection rates.

D) An action plan describing the measures that will be taken while operating under this Section to improve control of mercury emissions. This plan shall address measures such as evaluation of alternative forms or sources of ~~activated carbon~~**<u>sorbent or other mercury control technique</u>**, changes to the injection system, changes to operation of the unit that affect the effectiveness of mercury absorption and collection, and changes to other emission control devices. For each measure contained in the plan, the plan shall provide a detailed description of the specific actions that are planned, the reason that the measure is being pursued and the range of improvement in control of mercury that is expected, and the factors that affect the timing for carrying out the measure, with the current schedule for the measure.

e) Evaluation of Alternative Control Techniques for Mercury Emissions

1) During an evaluation of the effectiveness of the current sorbent, alternative sorbent, or other technique to control mercury emissions, the owner or operator of an EGU operating under this Section need not comply with the eligibility criteria for operation under this Section as needed to carry out an evaluation of the practicality and effectiveness of such technique, as further provided as follows:

A) The owner or operator of the EGU shall conduct the evaluation in accordance with a formal evaluation program submitted to the Illinois EPA at least 30 days in advance.

B) The duration and scope of the evaluation shall not exceed the duration and scope reasonably needed to complete the desired evaluation of the alternative control technique, as initially addressed by the owner or operator in a support document submitted with the evaluation program.

C) Notwithstanding 35 Ill. Adm. Code 201.146(hhh), the owner or operator of the EGU shall obtain a construction permit for any new or modified air pollution control equipment to be constructed as part of the evaluation of the alternative control technique.

D) The owner or operator of the EGU shall submit a report to the Illinois EPA no later than 90 days after the conclusion of the evaluation describing the evaluation that was conducted and providing the results of the evaluation.

2) If the evaluation of the alternative control technique shows less effective control of mercury emissions from the EGU than achieved with the prior control technique, the owner or operator of the EGU shall resume use of the prior control technique. If the evaluation of the alternative control technique shows comparable effectiveness, the owner or operator of the EGU may either continue to use the alternative control technique in an optimum manner or resume use of the prior control technique. If the evaluation of the alternative control technique shows more effective control of mercury emissions, the owner or operator of the EGU shall continue to use the alternative control technique in an optimum manner, if it continues to operate under this Section.

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