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

Marie E. Tipsord
Hearing Officer
Illinois Pollution Control Board
James R. Thompson Center
100 W. Randolph, 100 W. Randolph
Chicago, Illinois 60601-3218
tipsorm@ipcb.state.il.us

Gina Roccaforte, Assistant Counsel
Charles E. Matoesian, Assistant Counsel
John J. Kim, Managing Attorney
Air Regulatory Unit,
Division of Legal Counsel
Illinois Environmental Protection Agency
1021 North Grand Avenue, East
P.O. Box 19726
Springfield, Illinois 62794-9276
john.kim@epa.state.il.us
charles.matoesian@epa.state.il.us
gina.roccaforte@epa.state.il.us

SEE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that on July 28, 2006, I the undersigned caused to be filed electronically with the Clerk of the Illinois Pollution Control Board the APPEARANCE of Mary Frontczak on behalf of Prairie State Generating Company, LLC and the attached TESTIMONY OF DIANNA TICKNER, copies of which are herewith served upon you.

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

DATED: July 28, 2006

Mary Frontczak
Peabody Energy
701 Market Street
St. Louis, Missouri 63101-1826
(314) 342-7810

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APPEARANCE

I hereby file my appearance in this proceeding on behalf of Prairie State Generating Company, LLC.

_[s]_Mary_Frontczak____________________

Mary Frontczak
Reg. No. 6209264
Peabody Energy
701 Market Street
St. Louis, Missouri
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DATED: July 28, 2006

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TESTIMONY OF DIANNA TICKNER

My name is Dianna Tickner. I am a Vice President of Prairie State Generating Station, LLC ("Prairie State") and I am here today to testify on its behalf. Prairie State is directly affected by the proposed rule as it intends to construct a new 1500 megawatt pulverized coal electric generating unit ("EGU") facility in Washington County, Illinois. The facility, Prairie State Generating Station, is being designed to burn high-sulfur Illinois coal. In addition to my testimony, Prairie State will be providing detailed written comments on the proposed rule.

Prairie State submitted comments to the Illinois Environmental Protection Agency on the proposed rule on March 13, 2006. Those comments with minor corrections are incorporated herein as part of my testimony (Attachment 1). As indicated in those comments, Prairie State recommends that Illinois adopt the federal Clean Air Mercury Rule ("CAMR") as promulgated by the United States Environmental Protection Agency. Prairie State has significant reservations on going beyond CAMR, which will be elaborated on in the written comments. Specific to the Illinois proposed rule, Prairie State expressed general concerns with the feasibility of 90% mercury removal efficiency including the lack of any meaningful guarantees; the method for demonstrating compliance with the 12-month rolling average standard, and the monitoring requirements. Prairie State also identified concerns with specific provisions of the proposed rule.

Prairie State also reviewed the Temporary Technology Based Standard ("TTBS") and provided comments to the Illinois Environmental Protection Agency on June 1, 2006. Those comments were previously admitted as Exhibit 61 and are incorporated herein as part of my testimony (Attachment 2). Prairie State believes the TTBS is a necessary addition to the proposed rule to address any shortfalls in the capabilities of the technologies. As expressed in the comments, Prairie State does have some concerns with the current proposal, particularly for new generation.

In addition to the comments previously submitted, Prairie State is still concerned about the long-term capabilities of the available technologies to control mercury emissions from EGU flue gas. While there has been considerable testimony to date about the capabilities of the available technologies (*see e.g.*, testimony of Dr. Staudt and Mr. Nelson), that testimony appears to be based on several short term studies at facilities burning low to medium sulfur coal. Mr. Nelson did identify one study that is currently ongoing on a higher sulfur coal at Conesville Unit 6. As shown in Attachment 3, for coal sulfur content of 3.5% to 4% the preliminary results indicate a mercury removal efficiency of less than 20%. That removal efficiency is nowhere near the percent removal that would be required to comply with the proposed rule. As discussed in our March 13, 2006 comments, Prairie State to date has been unable to obtain a guarantee for 90% mercury removal on its high sulfur coal. *See* Attachment 4. Additionally, as the studies have been short-term, there is no long-term information on the effect the available technologies will have on balance of plant operations. Further study to assess high-sulfur coals and the impact on plant operations is needed before imposing requirements that are more stringent than CAMR.

ATTACHMENT 1

TO

TESTIMONY OF DIANNA TICKNER

PRAIRIE STATE Energy Campus

PRAIRIE STATE GENERATING COMPANY, LLC
701 Market Street, Suite 781
St. Louis, Missouri 63101-1826

March 13,2006
Corrected July 28, 2006

Via Electronic Mail and Federal Express

Ms. Laurel Kroack
Bureau of Air
Illinois Environmental Protection Agency
1021 North Grand Ave. East
Post Office Box 19276
Springfield, Illinois 62794-9276

Re: Comments on Draft Regulations for Control of Mercury Emissions from Coal-Fired Electric Generating Units

Dear Laurel:

Prairie State Generating Company LLC is pleased to provide these comments on the draft proposed regulations for Control of Mercury Emissions from Coal-Fired Electric Generating Units to be incorporated in 35 IAC 225. Prairie State will be directly affected by these regulations as it is planning to construct a new coal-fired power plant in Illinois.

Provided below are our general observations and comments on the draft proposed regulations followed by comments on specific provisions. In addition we are providing suggested revisions and additions to the proposed regulations to address our concems.

General Observations and Comments

In general, Prairie State recommends that Illinois adopt regulations that are consistent with the Clean Air Mercury Rule ("CAMR") promulgated by the United States Environmental Protection Agency ("EPA"). As to the draft regulations proposed, Prairie State has three general concerns: (1) the feasibility of 90% mercury removal efficiency; (2) method for demonstrating compliance with the 12-month rolling average standard; and (3) monitoring requirements.

As will be explained in detail below, the requirement of a 90% removal efficiency is beyond what has been proven in field studies to date. While Prairie State believes that technology available in the future may be capable of controlling emissions at that efficiency, such technology has not yet matured to the level that vendors are willing to provide guarantees. As such the current proposed draft regulations could impair Prairie

State's ability to finance and construct the **facility.** Consequently, Prairie State has proposed language that it believes meets the needs of all parties.

1. <u>A **Requirement** of 90% Reduction is Not Feasible</u>

As drafted, the regulations would require a 90% reduction in mercury emissions by 2009. This requirement appears to be based on a draft report titled **"Technology** for Controlling Mercury Emissions from Coal-Fired Power Plants in Illinois" ("Draft Mercury **Report"),** which has been posted on the **IEPA website.** For the reasons set forth below and in the enclosure to this letter, Prairie State believes that this requirement is not technologically feasible or commercially feasible.

The **majority** of the Draft Mercury Report is a fair and balanced discussion of mercury control. Where the Draft Mercury Report strays from basic scientific principles is when it optimistically predicts that a wide variety of control configurations can achieve 90% mercury control. These claims rest on limited testing where 90% control was **<u>occasionally</u>** achieved. On close inspection of the performance during the tests, one can make the case that 80-85% control is achievable, but not 90%. Establishing the standard at 90% would provide no margin of error and assumes continual operation at the best (but unproven) control removal efficiency. That virtually assures non-compliance will occur.

In order for a **facility** to continuously comply with a 90% mercury control requirement, **it** will normally need to operate at **control** levels around 95%. This margin is needed in order to account for the routine variability in emissions regardless of how well controlled a facility is. This higher control rate is needed to address excess emissions that occur during **malfunctions,** and process upsets. In developing CAMR, EPA evaluated technological capabilities and determined that 90% was not feasible at this time. Specifically, in discussing the use of activated sorbent injection in conjunction with conventional technologies to achieve 90 percent or greater mercury removal, EPA stated:

> Although EPA is optimistic that such controls may be available for use on some scale prior to 2018, it does not believe that such controls can be installed and operated on a national scale before that date. Based on tests, ongoing studies and discussions, we do not believe that the Hg-specific technologies have demonstrated an ability to consistently reduce Hg emissions by 90 percent (or any other level) at the present time.

70 Fed. Reg. 28606,28615 (May **18,2005).**

The Draft Mercury Report also overstates the long-term nature of the testing that has occurred to date. In fact virtually all of the tests cited in the Draft Mercury Report have been one month or less. It does not answer the question: what can these technologies produce over the long term? Short term testing of technology does not mean it will perform at the levels observed during those tests over the long-term or that the technology is commercially available in any true sense. Nor does it resolve all concerns about balance-of-plant effects. For example, the Draft Mercury Report tries to sweep aside the greatest concern about brominated activated carbon injection **("ACI") –** namely whether it will cause corrosion or other maintenance and availability problems over the long term. The Environmental Appeals Board recently reiterated that short-term data may not be **sufficient** to be the basis for a limit that has to be achieved over the long-term. ***See In*** re ***Newmont Nevada Energy Investment,*** L.L.C., PSD Appeal No. 05-04 (EAB **Dec**. 21,2005).

Finally, the Draft **Mercury** Report's discussion of vendor guarantees appears to have been taken directly from the vendor's literature. The discussion is very misleading and implies meaningful guarantees are readily available, which is not true. Prairie State has not been able to obtain a 90% mercury control guarantee even though the project includes an SCR and a wet FGD. Of note, the Draft Mercury Report indicates that such a technology configuration should easily be able to remove 90% of the mercury from bituminous coal. ***Id.*** at 36. The Draft Mercury Report also states the **"liability** to the vendor **....**is related to the cost of the project." ***Id.*** at 30. In most cases the cost of the **"project"** will be the cost of the sorbent injection system, which is in the $ 1 to 3 million range per unit. This vendor **liability** limit is typically much less than the costs the Owner's will experience if the mercury control guarantees are not met, including shutting down a **facility** resulting in direct consequences of lost jobs and economic benefit to the area as well as the indirect consequence of increased energy costs to consumers. Moreover, the vendors generally are smaller companies that do not have the financial wherewithal to ever make good on their extremely limited guarantees. In essence, vendors are guaranteeing that if their mercury controls **don't** work they will give you another one just like **it.** This doesn't help a power plant that is out of compliance with a state regulation.

For more details on the concerns raised by the Draft Mercury Report, see the enclosed letter from Steve Bjorklun of Bums and **McDonnell** (March **10, 2006).** Given the above, it is arbitrary for Illinois to include a 90% reduction requirement by 2009. Prairie State believes that the Department of Energy ('DOE") concurs with its position that the technology is not yet mature. DOE has initiated twelve long-term studies (12 to 36 months) to evaluate the viability of new and existing technologies with various coals. **DOE's** goal is to have these technologies ready for commercial demonstration by 2010, which is after Illinois' proposed regulation would go into effect. Prairie State recommends that Illinois follow this effort and include a provision in the regulations to incorporate **DOE's** results. Regulations should not be based on predictions of what can be achieved in the future as is the case here. They should be based on what has actually been achieved and technology that is demonstrated and commercially feasible.

Discussions with vendors, lenders and equity participants in the project indicate that, without an established, proven technology combined with suitable guarantees, the project may have to be delayed or possibly not built at all. To address the fact that the technology is not proven and vendors are unwilling to offer a viable guarantee that 90% can be achieved at all times or for the life of the facility, Prairie State is proposing the following language to be added as a new provision to 5225.237 to meet the needs of all parties:

> If a new EGU installs technology, at a minimum a particulate matter collection device, a flue gas **desulfurization** unit, a selective catalytic reduction device, and **sorbent** injection (other material or combination of materials), and due to technical shortfalls of such equipment, processes, or systems is unable to achieve the emissions standards as set forth in this regulation, the EGU **owner/operator** shall pursue a corrective action plan in conjunction with the Illinois EPA to determine alternative emissions standards for the EGU. Such corrective action plan shall include a requirement to determine the maximum practicable degree of mercury removal that can be continuously achieved with the installed technology. During the pendency of the correction action plan and the establishment of a site-specific mercury standard, the EGU will be deemed in compliance with the requirements of this regulation.

If Illinois is correct that 90% removal is continuously achievable, the above provision would never need to be implemented. Prairie State, however, believes that 90% is not continuously achievable (for the reasons explained above and in Mr. **Bjorklun's** letter) and thus the provision is necessary. Absent such a provision, well-controlled sources unable to achieve the standard would be in a perpetual state of noncompliance or be forced to shut down, leaving a significant void in the generation of needed power. Such a provision would also bridge the gap pending the outcome of **DOE's** studies.

2. <u>Method of Assessing Compliance Could Lead to Anomalous Results</u>

Assessing compliance over a 12-month period as proposed is helpful, particularly given the large variability in mercury emissions. Illinois' proposal to assess compliance on a monthly basis and then average those 12 months to determine compliance appears to be based on the trading program established by EPA, which is not relevant to Illinois' proposal. It would be simpler to require plants to use the prior year of data to demonstrate compliance with the limits, a true rolling annual limit. Such an approach would avoid the adverse effects of anomalous months **(i.e.,** a few days of operation at higher than normal mercury levels) and would not result in a finding of **non-compliance** for an entire month if a 12-month rolling average exceeded the mercury limits [see draft § 225.1301. Thus, Prairie State would suggest that a plant be required to report only its twelve month rolling average based on the previous years worth of data.

3. Monitorina Reauirements Should be Consistent with CAMR

Currently, there are many questions about EPA's mercury monitoring requirements and whether **CEMs** will accurately measure mercury emissions under all conditions. 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 highly likely that some changes will be made by EPA. The question then arises: Does Illinois plan to revise its mercury monitoring requirements if EPA revises its regulations? The draft regulations incorporate some EPA requirements by reference but they also include some 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 monitors for facilities in Illinois.

Additionally, there are potential concerns with the methods (coal sampling as proposed, or monitoring of inlet to control technology) for demonstrating compliance with the percent removal standard. There is limited data available to confirm that these methods would provide a consistent reliable measure of percent removal.

Specific Comments

Below are Prairie State's comments on specific provisions in the draft proposed regulations.

§ 225.130 – definition of "electric generating unit": An EGU is defined to include "fossil fuel-fired" boilers and combustion turbines. Since EPA decided only to regulate mercury emissions from coal-fired units, why the more inclusive definition? Note that § 225.605 only applies to coal-fired units. **[CORRECTION — Disregard this comment as the definition** of electric generating unit is not in the proposed rule.]

§ 225.130 – definition of "rolling 12-month basis": The definition implies that a 12-month average is calculated based on monthly averages. The definition excludes months when a boiler never operates. It presumably includes months when the boiler operates as little as one day. This can lead to anomalous results. As noted above, a better way to smooth results **would** be to look at all data for the prior 12 months and then calculate the average emission rate or percentage reduction making it a true annual average. Emissions during periods of startup and shutdown should also be excluded as technologies, such as SCR which aid in mercury removal, are not operational during those periods. Such an exclusion would be consistent with the NSPS.

§ 225.140 and 225.202 – Standard Lab uses ASTM D6722-01 "Standard Test Method for Total Mercury in Coal and Combustion Residues by Direct Combustion Analysis" to determine Mercury in coal for Draft Mercury Reporting under the MACT rule and other Draft Mercury Reporting. The draft proposed regulations does not list ASTM D6722-01 as an acceptable method. However, 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). This draft needs to include ASTM D6722-01 as an acceptable method.

§ 225.210(e) – Compliance should be judged at the source, not the unit level. 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.

§ 225.220(c)(1) – It is unclear what mercury requirements Illinois considers to be **"federally** enforceable." Illinois' requirements go far beyond CAMR and as a result are state standards, not federally enforceable limits.

§ 225.230 – Given the definition of a 'rolling 12-month basis" there appears to be no difference between compliance options (a) and (b).

§ 225.230 (d)(3) – This results in multiple violations when it may be only one unit that has compliance issues.

§ 225.232 – Averaging provisions appear 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?

§ 225.237 – The limits on new sources go beyond **EPA's** § 1**11**(b) mercury limits for new coal-fired power plants and are not federally enforceable.

It is unclear how the provisions of subsection (b) operate when the beginning of compliance is delayed by 150 or 180 days. The regulations do not explain how this delay works given the fact that compliance is judged on a 12-month rolling basis.

§ 225.240(b) – **EPA's** regulations require all monitors to be certified by no later than January 1,2009 and for compliance monitoring to begin on January 1,2009. The Illinois regulations would require monitoring to be in on March 1, 2009. The draft regulations do not explain the timing difference. **[TION — IEPA addressed this comment in the proposed rule by requiring monitoring to begin on January 1, 2009].**

Certifying a mercury monitor within 90 days of commercial operation will be next to impossible. This is much shorter than the period allowed in NSPS for monitor certifications. Considering that mercury emissions are a long term not a short-term issue, a more reasonable time to certify the monitors should be allowed. Prairie State would suggest an 180-day period.

§ 225.240 (c)(1) – This is a particularly punitive provision considering the developmental state of mercury monitors, difficulties that can be expected in certifying the monitors and the very short period allowed to certify the monitors in 225.240 (b)(2).

§§ 225.240(d) and 222.250(a)(2)(E) – These provisions are premised on a level of performance and dependability that mercury CEMs have yet to demonstrate. As a result, these provisions may prove unworkable for mercury CEMs. **[CORRECTION — The reference to § 222.250(a)(2)(E) should be to § 225.250(a)(3)(E).]**

§§ 225.250 (a)(3)(D)(i), (ii) and (iii) – The 120 days seem excessive considering the facility is only being allowed 90 days to get the monitors certified. The review time adds to the violation period if the monitor certification is not approved.

We appreciate the opportunity to provide these comments. Should you have any questions regarding our comments, please do not hesitate to contact me at (314) 342-7646 or (314) 651- 3665.

Sincerely,

Colin M. Kelly

Enclosure

cc: Douglas P. Scott

ATTACHMENT 2

TO

TESTIMONY OF DIANNA TICKNER

PRAIRIE STATE Energy Campus

PRAIRIE STATE GENERATING COMPANY, LLC
701 Market Street. Suite 781
St. Louis. Missouri 63101-1826

June 1,2006

Federal Express
Electronic Mail

Laurel Kroack, Director
Illinois Environmental Protection Agency
1021 North Grand Ave. East
PO Box 19276
Springfield, Illinois 62794-9276

Re: Comments on Temporary Technology-Based Standard to be Incorporated into Illinois' Draft Regulations for Control of Mercury Emissions from Coal-Fired Electric Generating Units

Dear Laurel:

Prairie State Generating Company, LLC's is pleased to provide the following comments on the proposed Temporary Technology-Based Standard to be incorporated into Illinois' draft proposed regulations for Control of Mercury Emissions from Coal-Fired Electric Generating Units to be incorporated in 35 IAC 225. Prairie State will be directly affected by these regulations as it is planning to construct a new coal-fired power plant in Illinois.

Prairie State's comments are focused on the provisions relating to new units, but generally are equally applicable to those for existing units. In addition to the following comments, Prairie State also has technical comments as indicated on the attached markup of the proposed revision.

We appreciate the opportunity to provide these comments. Should you have any questions about our comments, please do not hesitate to contact me.

Sincerely,

Dianna Tickner

Dianna Tickner

Enclosures
cc: Colin Kelly
Jim Ross - IEPA

Questions on Illinois **Proposed Mercury** Standard

1. General comment – Why is eligibility for the technology based altemative tied to the use a particular sorbent (halogenated activated carbon)? Such a linkage is too restrictive and ignores new reagents and technologies that are being developed that may be as or more effective than activated carbon. 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 requiring an EGU to go through the alternative process. To implement this concept, we would recommend replacing 'halogenated activated carbon" with 'sorbent or reagent approved by IEPA".

2. § 225.238(a)(1) – Does this section apply to sources commencing commercial operation after January **1, 2009?** As currently drafted, this section read in isolation is ambiguous and could be read to only apply to new sources that commenced operation before January 1,2009. It might be better to word the eligibility requirement in the positive (for sources at which the first EGU commences operation after January **1, 2009),** rather than as a double negative.

3. § **225.238(b)(1) –** Is this reference to BACT for eligibility only or is it intended to reopen a BACT determination made in the context of PSD permitting for a new EGU? As currently drafted, it can be read to mean that a new BACT determination would have to be made for the EGU to be eligible.

4. § **225.238(b)(2) –** Does **IEPA** intend that altemative rates of injection of halogenated activated carbon may be included only in a federally enforceable operating **permit?** For new sources, this provision should also allow for similar provisions to be included in a federally enforceable construction permit. For example, **Prairie** State's permit includes provisions for determining the optimum rate of sorbent injection. That provision should be acceptable as an alternative to the default rates included in this provision.

   What is the basis for the proposed injection rates? Do they effectively **consider** all the variables associated with mercury removal **(e.g.,** chlorine and mercury **content** of the coal, SCR catalyst and **quantity,** temperature of the gases going through the air preheater, type of particulate collection device (cold or hot dry ESP or baghouse), installation of additional down stream air pollution control devices such as a wet ESP)? We believe a technology effectiveness evaluation process more in line with the one defined in the PSD permit for Prairie State best serves the intended purpose. Thus, we would ask that the Agency look at Option B (Condition **2.1.2(c)(ii)(A)(II))** in the Prairie State permit as a process for evaluating mercury technologies.

What is the basis for not including a provision similar to § 225.234(b)(2)(D) (allowing the use of lower injection rates if particulate matter emissions are adversely impacted) in § 225.238 for new **EGUs?** Prairie State recommends that it be included and that **"safety issues"** be added as a basis for lowering the injection rate. Presique Island recently had a fire in their **TOXICON baghouse** due to excessive levels of carbon in the baghouse.

5. § 225.238(c)(2)(A) – What is the purpose for recording the activated carbon feed rate on an hourly average basis? Does the Agency also intend to require monitoring and recording of the mercury content of the coal and capture efficiency on an hourly average basis, which Prairie State believes is unnecessary7 Prairie State is concerned that this requirement **will** eventually translate the annual merwry limit into an hourly limit.

6. **§ 225.238(d) –** For new facilities whose construction permit already **includes** a provision regarding **mercury** control and the use of a sorbent, why is a new or revised operating permit required? Could the source indicate in its initial **Title** V application that it is applying to operate under the Technology-Based Standard in accordance with its PSD permit? A new facility that incorporated provisions regarding mercury control should not have to go through further permit review and public participation. Prairie State has a similar concern with respect to § 225.238(e)(1)(C).

7. There are some timing issues to be worked out. Under the proposed rule **(§ 225.237),** compliance with the mercury standard **commences** on the date of the initial performance test. Application to use the Technology-Based standard is to 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. However the initial **Title** V application is not due within one year of commencing operation. Theoretically, a facility would need to submit a Title V permit to comply with the Technology- Based Standard three months after initial startup and before the **compliance** period is complete. One way to solve this problem is to delink the application to use the technology Standard from the Title V process, **i.e.,** include the requirement in the construction permit.

Section 225.234 Temporary Technology-Based Standard for EGUs at Existing Sources

a) General

1) At a source with EGUs that commenced commercial operation on or before December 31,2008, 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 225.230 of this Subpart, the owner or operator of the EGU may temporarily comply with the requirements of this Section, through June 30,2015, 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 during the period that it is operating under this Section.

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 equipped and operated with the air pollution control equipment or systems that include injection of halogenated activated carbon or other or mercury control technology that is approved by the Agency, and either (1) a cold-side electrostatic precipitator or (2) a fabric filter. (The Agency shall approve alternate mercury control technologies based on the effectiveness and cost of the alternate technology proposed.)

2) The owner or operator of the EGU is injecting halogenated activated carbon in an optimum manner for control of mercury emissions, which shall include injection of Alstrom, Norit, Sorbent Technologies, or other halogenated activated carbon or other mercury control technology approved by the agency, 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, [Activated carbon injection rates are a function of many variables, like chlorine in the coal, amount of Hg in the coal, amount of SCR catalyst, type of catalyst, type of control equipment

(ESP or baghouse, wet or dry FGD)etc., setting a bard injection rate is not proper]… unless other provisions for injection of halogenated activated carbon (or other mercury control technology) are established in a federally enforceable operating permit issued for the EGU, with an injection system designed for effective absorption of mercury, considering the configuration of the EGU and its ductwork. For this purpose, flue gas flow rate shall be determined for the point of sorbent injection, 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 100° 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.

[B1]

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.

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 operator of the EGU demonstrates that such rate or rates are needed so that carbon injection would not increase particulate matter emissions or opacity so as to threaten compliance with applicable regulatory requirements for particulate matter or opacity, does not effectively increase mercury control or causes a safety issue.

3) The total capacity of the EGUs that operate under this Section does not exceed the applicable value below:

A) For the owner or operator of more than one existing source with EGUs, 25 percent of the total rated capacity, in MW, of all the EGUs at such existing sources that it owns or operates, other than any EGUs operating pursuant to Section 225.235 of this Subpart.

B) For the owner or operator of only a single existing source with EGUs (i.e., City, Water, Light & Power, City of Springfield, ID 167120AAO; Electric Energy, Inc., ID 127855AAC; Kincaid Generating Station, ID 021814AAB;

and Southern Illinois Power Cooperative/Marion Generating Station, ID 199856AAC), 25 percent of the total rated capacity, in MW, of the all the EGUs at such existing sources, other than any EGUs operating pursuant to Section 225.235 of this Subpart.

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 an EGU operating pursuant to this Section shall also:

A) Through December 31, 2012, maintain records of the usage of activated carbon, the exhaust gas flow rate from the EGU, and the activated carbon feed rate, in pounds per million actual cubic feet of exhaust gas at the injection point, on a weekly average.

B) Beginning January 1, 2013, monitor activated carbon feed rate to the EGU, flue gas temperature at the point of sorbent injection, and exhaust gas flow rate from the EGU, automatically recording this data and the activated carbon feed rate, in pounds per million actual cubic feet of exhaust gas at the injection point, on an hourly average. (Or other appropriate parameters for the mercury control technology approved by the Agency.)

C) If a blend of bituminous and sub-bituminous coal is fired in the EGU, records of the amount of each type or coal burned and the required injection rate for injection of halogenated activated carbon, on a weekly basis. (Or other appropriate parameters for the mercury control technology approved 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 225.230 of this Subpart would otherwise have to be demonstrated. For example, the owner or operator of an EGU that is applying to operate the EGU pursuant to this Section on June 30,2010, when compliance with applicable mercury emission standards must be first demonstrated, shall apply by March 31,2010 to operate under this Section.

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:

i) If it operated pursuant to this Section during the period of June 2010 through December 2012 and it seeks to operate pursuant to this Section during the period from January 2013 through June 2015.

ii) 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 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 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 225.230(a) 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 injection 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, changes to the injection system, changes to operation of the unit that affect the effectiveness of mercury absorption and collection, changes to the particulate matter control device to improve performance 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 below:

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 owner 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 wntrol technique in an optimum manner, if it continues to operate under this Section.

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.[B2]

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, OR OTHER MERCURY CONTROL TECHNIQUE 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 system a using activated carbon.

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 A SORBENT~~halogenated activated carbon~~ in an optimum manner for control of mercury emissions, which MAY~~shall~~ include injection of Alstrom, Norit, Sorbent Technologies, or other SORBENT ~~halogenated activated carbon~~ 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 A SORBENT (or other mercury control technique) ~~halogenated activated carbon~~ 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, 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 100° 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.

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 feed rate to the EGU, flue gas temperature at the point of sorbent injection, and exhaust gas flow rate from the EGU, automatically recording this data and the activated carbon 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 sub-bituminous coal is fired in the EGU, records of the amount of each type or coal burned and the required injection rate for injection of halogenated activated carbon, on a weekly basis.

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 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 injection 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, OR OTHER MERCURY CONTROL TECHNIQUE, 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 below:

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 owner 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.

[B1]The rates listed do not make any sense. All testing has shown that AC injection is more effective (under similar conditions with similar emission control equip.) f a a unit firing bituminous coal instead of subbituminous. The required injection rate f a b i i should be less than subbituminous.

[B2]I'm not sure what they are trying to accomplish. Problems meeting the 90% control requirement will likely be common f a multiple units. It would be logical to demonstrate a technology on only one unit.

U.S. Department of Energy

National Energy Technology Laboratory

April 25,2006

Clarification of the U.S. Department of Energy's Perspective on the Status of Mercury Control Technologies for Coal-Fired Power Plants

On April 18, 2006 the Pennsylvania Federation of Sportsmen's Clubs (PFSC) issued a press release through PRNewswire that presented a somewhat inaccurate account of the U.S. Department of Energy's perspective on the current status of mercury control technologies for coal-fired power plants. The press release was based on statements made by Thomas J. Feeley, III, a technology manager at the Department's National Energy Technology Laboratory (DOE/NETL), during an appearance on WPSU-TV's public affairs program -- *Pennsylvania Inside Out* -- that aired April 14th in which Mr. Feeley discussed mercury-related topics with the Secretary of the Pennsylvania Department of Environmental Protection Kathleen McGinty. Given the nature and format of *Pennsylvania Inside Out* program, it is understandable that PFSC may have misinterpreted the context of some of Mr. Feeley's statements concerning the commercial availability and cost of mercury controls. The following information is provided to clarify DOE/NETL's perspective on the readiness of technologies for controlling mercury emissions from coal-fired power plants and their associated costs.

DOE/NETL's Mercury Control Technology Research & Development Program

DOE/NETL, in partnership with a number of key stakeholders, has been carrying out a comprehensive research program focused on the development of advanced, cost-effective mercury control technologies since the mid-1990s. Considerable progress has been made during that time in advancing our basic understanding of mercury in coal-fired power plant flue gas and what technologies could be used to control power plant mercury emissions. However, 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.*** Several key points related to the status and cost of mercury control technologies are summarized below.

- *Development Status of Mercury-Specific Control Technology*

  Under DOE/NETL's current field testing activity mercury-specific control technologies such as activated carbon injection (ACI) are being tested at a number of coal-fired power plants. These tests have yielded very promising results in most cases. For instance, improved activated carbon sorbents have been developed and are being tested that can capture the more difficult to remove elemental form of mercury. Elemental mercury is the predominant species of mercury formed when burning lower-rank coals (subbituminous and lignite) that have low chlorine content. The progress achieved under DOE/NETL's field testing program has led to several recent announcements of sales of ACI systems to the **electric-utility** industry.

However, as alluded to above, one size does not fit all in regards to controlling mercury fiom the broad range of coals burned by, and various pollution control equipment installed on, today's coal-fired power plants. Higher-sulfur bituminous coals are a **case** in point. During combustion, plants burning medium to high sulfur coal *can* produce acid gases, such as sulfur **trioxide** (SO_3), that compete with mercury for bonding sites on the activated carbon. Consequently, the presence of SO_3 in coal combustion flue **gas** may limit the effectiveness of mercury control via ACI. A recent **DOE/NETL** field test on a plant burning a high-sulfur Ohio coal has shown ACI to be relatively ineffective in capturing mercury. **DOE/NETL** has scheduled additional ACI field tests at five bituminous coal-fired units to address this concern.

Another technical performance issue that needs **further** investigation relative to ACI is the **type** of particulate control device installed on the power plant. The majority of U.S. power plants **are** equipped with electrostatic precipitators (ESP) to remove particulate matter **(i.e.,** fly ash) fiom the flue gas, while some use fabric filters. Activated carbon is injected upstream of the particulate control device to enable simultaneous capture of the mercury and removal of the spent carbon and fly ash. The effect of continuous long-term ACI operation on a power plant's particulate control device is still under investigation. DOE/NETL field testing at a **bituminous-fired** power plant equipped with an ESP with a relatively small collection area has shown that ACI *can* have a detrimental effect on ESP performance and lead to carbon breakthrough **from** the ESP which *can* effect operations of the downstream **sulfur** dioxide **(SO_2)** emissions control equipment. Therefore, further field testing is being carried out to assess this and other technical performance issues.

Finally, **DOE/NETL's** current mercury control field testing program has been limited to testing at 28 coal-fired units, representing about only 2.3% of the **1,165** coal-fired generating units in operation in the United States.

- *Co-Removal of Mercury in Flue Gas Desulfurization Systems*

Mr. **Feeley** stated that ***"there is existing technology that has already proven to be able to take mercury out [of coal combustion flue gas]."*** This statement was made in the context of Pennsylvania's proposed mercury control regulation that is based on the **co-removal** of mercury in flue gas **desulfurization** systems **(i.e.,** wet scrubbers) designed to remove SO_2. Wet scrubbers have been employed by the electric utility industry for more than thirty years to meet ever increasingly stringent SO_2 regulations, thus, it is considered an "existing technology."

Recent data collected by **DOE/NETL,** the U.S. Environmental Protection Agency, and others indicate that wet scrubbers **are** also effective in capturing the oxidized form of mercury. Oxidized mercury is the form of mercury most commonly found when combusting higher chlorine bituminous coals, such as those mined and burned in Pennsylvania. This mercury is soluble and can be washed out in the scrubber along with the SO_2. It is very important to note that the co-removal of mercury across existing technology such as wet scrubbers will vary significantly based on the chemical forms of mercury present. Recall above that low-rank coals tend to produce more elemental mercury, which is insoluble and can not be removed in the scrubber. Bituminous coals also produce some elemental mercury that will not be captured in the scrubber. And even for the oxidized mercury, the level of removal across wet scrubbers has been shown to range from about *70%* to *90%.* Further complicating the overall effectiveness of wet scrubbers in removing mercury is the fact that some of the mercury captured by the scrubber may be re-released through a yet-to-be completely understood process in which the oxidized mercury is chemically reduced back to its elemental form. DOE/NETL is carrying out research to better understand and control this phenomenon.

Regarding Mr. Feeley's statements concerning the cost of mercury control via scrubbers, under the proposed Pennsylvania mercury regulation, mercury reductions will result from the installation of wet scrubbers to meet the new Federal Clean Air Interstate Rule that calls for further cuts in SO_2 (and nitrogen oxide) emissions. Therefore, it can be argued that the cost of mercury reduction is "free," that is, it is a co-benefit of the cost of installing and operating the scrubber for controlling SO_2. However, there could be relatively significant future costs associated with the impact of mercury control on the management of the solid byproducts produced by the scrubber that is discussed below.

- *Cost of Activated Carbon Injection*

While mercury control via ACI is "relatively inexpensive" on a capital-cost basis, the cost reported by Mr. Feeley of $5 - $7 per kilowatt was presented to contrast with the relatively high capital cost of SO_2 scrubbers. That is, a utility would not choose to install a high-capital cost wet scrubber for the sole purpose of capturing mercury, but would likely choose a less expensive technology like ACI. Moreover, it is important to note that capital costs are only one part of the overall levelized cost of controlling mercury. A preliminary DOE/NETL economic analysis has revealed that the annual operating and maintenance (O&M) costs associated with ACI represent over 80% of the total levelized cost. Annual O&M costs consist of several components, including: (1) activated carbon consumption; (2) activated carbon disposal; (3) other costs (electric power, O&M labor, and spare parts); and (4) the cost of the management and disposal of the power plant's coal combustion byproducts (which we will discuss in more detail below). Primarily, the annual O&M costs are dominated by activated carbon consumption costs since the ACI mercury control technology involves the continuous injection of activated carbon into the flue gas.

The ACI capital cost of $5 - $7 per kilowatt stated by Mr. Feeley also represents a situation where the only new equipment being installed is the activated carbon storage silo and injection system. However, there will be cases where a new fabric filter is added in order to separate the collection of the activated carbon from the collection of the bulk of the plant's fly ash. Such an ACI configuration, known as TOXECON™ is currently being tested under DOE's Clean Coal Power Initiative at WeEnergies' 270 megawatt (MW) Presque Isle Power Plant located in Marquette, Michigan. For this application, the total capital cost for the ACI system, including the new fabric filter, is approximately $126 per kilowatt.

- *Impacts of Mercury Control on Cost of Electricity*

Mr. Feeley's statement that DOE/NETL's preliminary economic analysis of ACI indicate that impacts on electric utility rates are not expected to be significant is correct, but must be considered in the context that it represented the "best case" economic scenario. The severity of the potential impact on the cost of electricity (COE) depends on several factors, including: (1) the rate in which the activated carbon is injected to comply with a given mercury control regulation; (2) the type of ACI system selected; (3) equipment retrofit difficulties; and (4) the impact of ACI on current coal combustion byproduct management and disposal practices. While preliminary ACI cost estimates are encouraging, they generally assume an uncomplicated retrofit and minimal economic impact due to the installation of the ACI system. The encouraging economics reported by Mr. Feeley are also based on the assumption that mercury control via ACI will not cause any balance-of-plant impacts such as particulate control equipment performance, but more significantly, changes in the disposal and marketing (sale) of coal byproducts. Based on DOE/NETL's economic analysis, potential future regulatory implications as to how coal byproducts are managed due to concerns about mercury could increase the COE associated with mercury control by a factor of two-to-four compared to the mercury control COE without byproduct impacts. This is discussed in more detail below.

- *Potential Impacts of Mercury on Coal Byproducts Management and Associated costs*

One topic not discussed during *Pennsylvania Inside Out* is the potential negative impacts of mercury control on the sale and disposal of coal combustion byproducts such as fly ash and the solids generated by SO_2 scrubbers, which in turn could dramatically increase the cost of mercury control. Currently, coal byproducts are regulated as non-hazardous and many power plants sell their fly ash and scrubber solids for use in cement and concrete, or in making wallboard. Because mercury control, whether by ACI or via SO_2 scrubbers, will result in increases, albeit small, in the concentration of mercury in coal byproducts, there is the possibility that these materials may be regulated in a manner that would lead to higher disposal costs and loss of current beneficial-use markets. This is driven by concerns that the mercury in the coal byproducts could be released to the

> environment. Because of the concern about the impact of mercury on coal combustion byproducts, DOE/NETL's preliminary estimate of the cost of ACI discussed above looked at two scenarios – one without any byproduct impacts and one with byproduct impacts. *The byproduct impact scenario as much as tripled the cost of mercury control on a dollar per pound of mercury removed basis and increased COE by a factor of as much as four for some coal-fired generating units.* In response, DOE/NETL is carrying out research directed at evaluating the fate of mercury in coal combustion byproducts and developing ways to ensure that the mercury is not released.

Additional information on DOE/NETL's mercury control technology R&D program can be found at: http://www.netl.doe.gov/technologies/coalpower/ewr/mercury/index.html

ATTACHMENT 3

TO

TESTIMONY OF DIANNA TICKNER

U.S. DOE's Hg Control Technology RD&D Program—Significant Progress, But More Work to be Done!

A&WMA's 99th Annual Conference & Exhibition
Hg Control Technology Panel

June 23, 2006
New Orleans, Louisiana

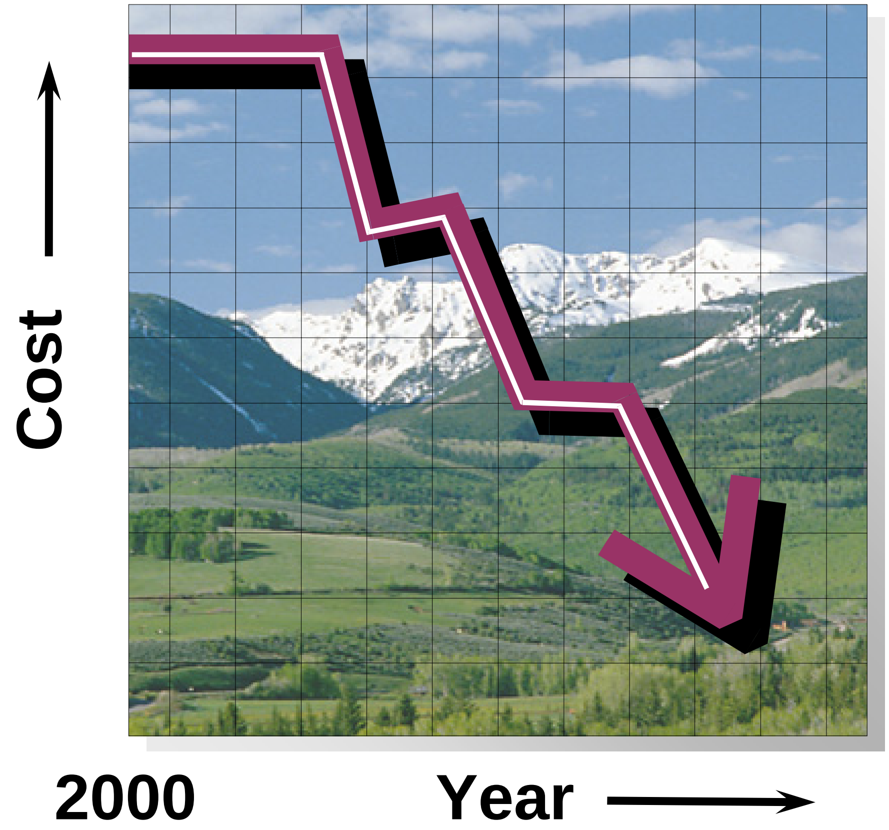
Thomas J. Feeley, III
thomas.feeley@netl.doe.gov
National Energy Technology Laboratory

Outline

- Background
- Phase II project update/Phase III project descriptions
- BOP and related technical issues
- Preliminary economic assessment
- Byproduct-Hg issues/potential economic impacts
- Conclusion

Mercury Control Technology Program
Performance/Cost Objectives

- **Have technologies ready for commercial demonstration by:**
  - **2007 that can reduce "uncontrolled" Hg emissions by 50-70%**
  - **2010 for all coals that can reduce "uncontrolled" Hg emissions by +90%**
- **Reduce cost by 25-50% compared to baseline cost estimates**



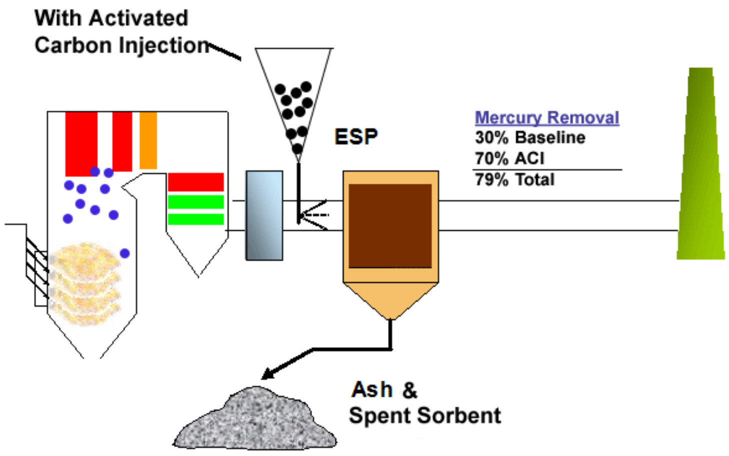
Baseline (1999) Costs: $60,000 / lb Hg Removed

NETL's Hg Control Technology R&D

- **Sorbent injection technology**
  - Carbon-based sorbents
    - Treated AC
    - Untreated AC
  - Non-carbon-based sorbents
    - Amended Silicates
    - MinPlus
- **Oxidation additives and catalysts**

Mercury Control Technology R&D
Improved Results with Western Coals

- **Previous pilot-scale studies and field testing suggested lower-rank coals more difficult to control due to lower Cl/higher element Hg content**
- **Focused R&D on development and testing of chemically treated (e.g., halogenated) activated carbon (AC)**
- **Treated AC has achieved 70-90% total Hg capture with western coals in recent field tests on both ESP and fabric filter configurations**
- **However, additional demonstration of Hg capture technologies needed to address balance-of-plant and byproduct impacts**



Balance-of-Plant Issues/Lessons Learned

TOXECON Retrofit for Hg and Multi-Pollutant Control
U.S. DOE Clean Coal Power Initiative, Round 1

Presque Isle Power Plant, Marquette, MI

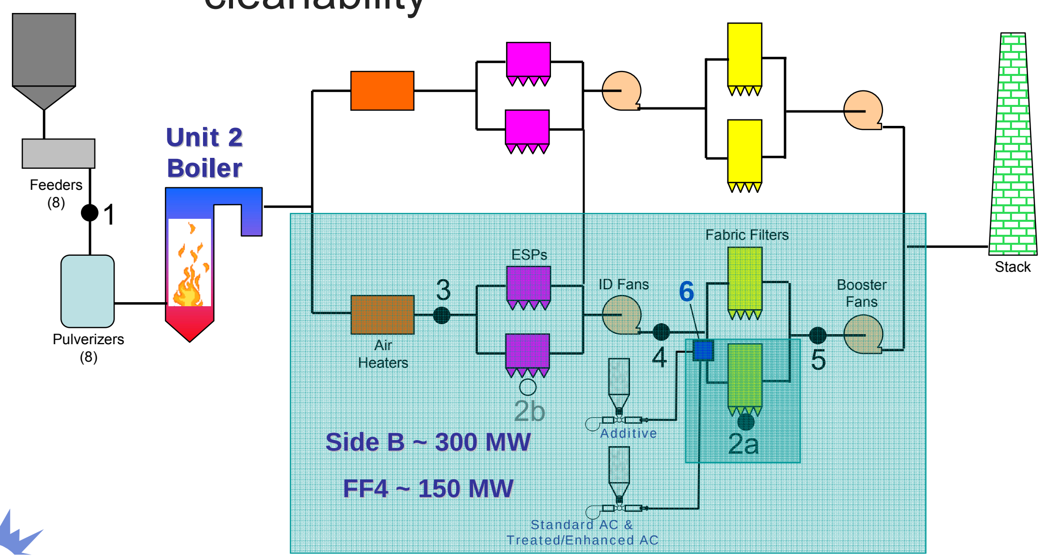
- **Plant was built in early 1950's and expanded over the years to 9 coal fired Units**
- **Nine units total 625 MW representing approximately 50% of the power generation in Michigan Upper Peninsula**
- **Units 7,8 & 9 are 90 MW units burning western bituminous, PRB coal**
- **PIPP currently sells fly ash for concrete**

Problem with Overheating Powdered Activated Carbon at Presque Isle

- **Hot burning embers found on February 27, by March 2 all hoppers had embers**
- **System bypassed and opened to atmosphere, worsened situation, causing flames that damaged 200 bags in 2 (of 10) compartments**
- **Likely cause is excessive temperatures from hopper heaters**
- **PAC can ignite at temperature greater than 700 ºF. (welding, cutting, hopper heaters)**
- **Investigation is ongoing**

Mercury Control Options for TXU's Big Brown

- **Project Objective: Evaluate long term feasibility of activated carbon (AC), treated carbon, and additive injection for mercury control**
  - ≥ 55% mercury removal
  - Evaluate balance-of-plant (BOP) impacts
    - Increase in ΔP across FF4 over time
    - Increased difficulty in bag cleanability



- **Possible sources of BOP impacts:**
  - Injection of sorbent/additive material causing filter blockage.
  - Changes in flue gas or ash chemistry due to addition of sorbent/additive materials.
  - Changes in operating conditions during test period:
    - Flow rate variations (rebalancing of flow, increased flow)
    - Frequent flow bypass (when ΔP exceeded 10" H_2O)
    - Temperature fluctuations
    - Use of ash conditioning
    - Variation in fuel blend
    - Load variation
    - Unplanned outages, chemical and morphology analysis is ongoing

Upcoming NETL Field-Testing at Bituminous Units

Bituminous Unit	APCD Configuration	Start Date	Mercury Control	Coal Sulfur Content (wt%)
Yates Unit 1	CS-ESP / Wet FGD	September 2005	Oxidation Catalysts	0.93
Yates Unit 1	CS-ESP / Wet FGD	November 2005	MerCAP™	0.93
Yates Unit 1	CS-ESP / Wet FGD	Fall 2005	Wet FGD additive	0.93
Lee Unit 1	CS-ESP	November 2005	Enhanced ACI	0.77
Lee Unit 3	CS-ESP / SO_3 conditioning	1st Quarter 2006	Integrated Approach	0.82
Miami Fort Unit 6	CS-ESP	1st Quarter 2006	Amended Silicates™	2.21
Conesville Unit 6	CS-ESP / Wet FGD	March 2006	Enhanced ACI	3.00
Portland Unit 1	CS-ESP	March 2006	Mer-Cure™	2.01
Gavin Station	CS-ESP / Wet FGD	Unknown	TOXECON™ II	3.76

NETL

Preliminary Results of Field Testing at Conesville Power Plant – Impact of High-S Coal

- **400 MW T-fired PC burning high-S (3.5-4%) bituminous coal equipped with ESP and wet FGD**
- **Very little baseline Hg removal**
- **Initial tests w/ treated and untreated activated C yielded only 5-31% Hg removal @ 9-18 lb/MMacf**

Conesville Power Plant, Coshocton, OH

- **2nd round of parametric testing with "improved" sorbents yielded worst results (3-13% removal), even with improved AC distribution**
- **High sulfur trioxide (SO_3) suspected to compete with sorbtion sites on AC or otherwise compromise AC Hg removal capabilities**

NETL

DOE Hg Control RD&D Timeline in Sync with the Clean Air Mercury Rule (CAMR)

Complete field testing of technology capable of 50-70% Hg capture

Complete field testing of technology capable of 90%+ Hg capture

DOE initiated field testing of technologies that can achieve 90%+ mercury capture in early 2006

Full-scale commercial demonstrations

Commercial deployment

2005 | 2007 | 2010 | 2015 | 2018 | 2020

CAMR Issued

Toxecon™ Clean Coal Demo Project

CAMR Phase I
38 ton/year cap
via Co-Benefit
(NOx & SO_2)
Controls

CAMR Phase II
15 ton/year cap
via Hg Specific
Controls

NETL

RD&D – Research, Development and Demonstration

Phase II Field Testing Economic Analysis

DOE/NETL's Phase II Mercury Control Technology Field Testing Program

Preliminary Economic Analysis of Activated Carbon Injection

Prepared for

U.S. Department of Energy
Office of Fossil Energy
National Energy Technology Laboratory
Innovations for Existing Plants Program

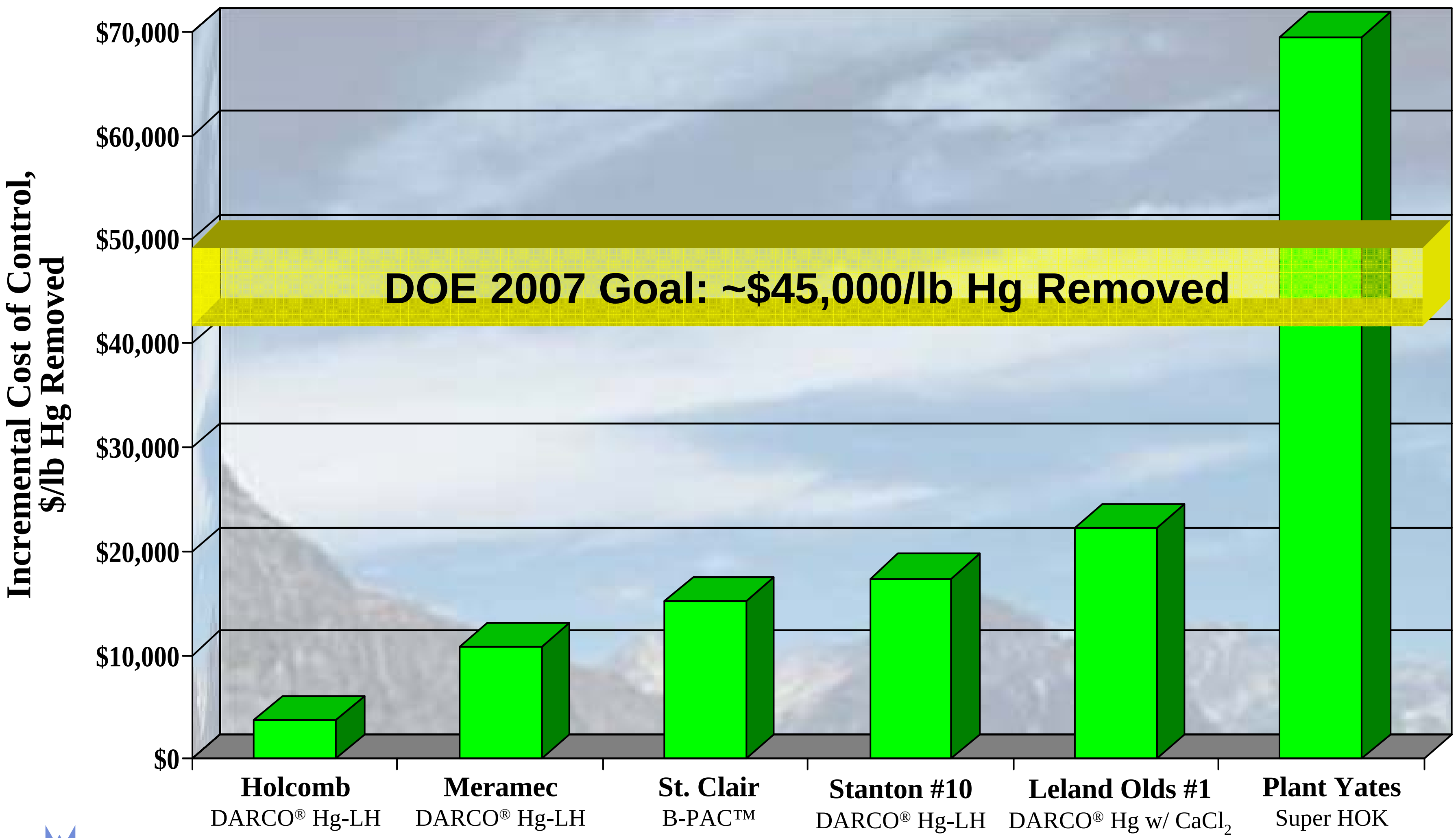
Prepared by

Andrew P. Jones[1], Jeffrey W. Hoffmann[2], Dennis N. Smith[3], Thomas J. Feeley, III[2], and James T. Murphy[1]

[1] Research and Development Solutions, LLC
[2] U.S. Department of Energy, National Energy Technology Laboratory
[3] U.S. Department of Energy, Office of Fossil Energy

April 2006

Incremental Cost of 70% ACI Mercury Control



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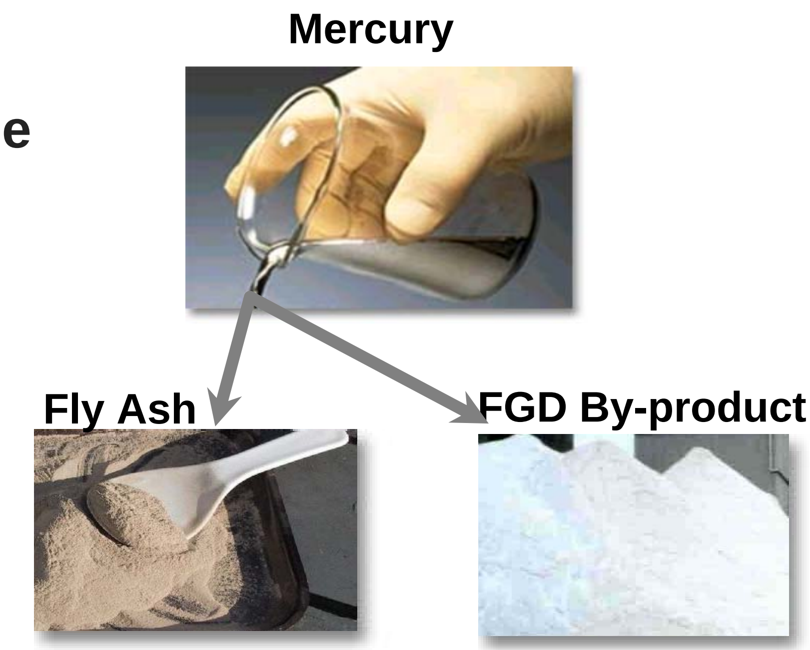
Key Challenges to Continued/Increased By-Product Use

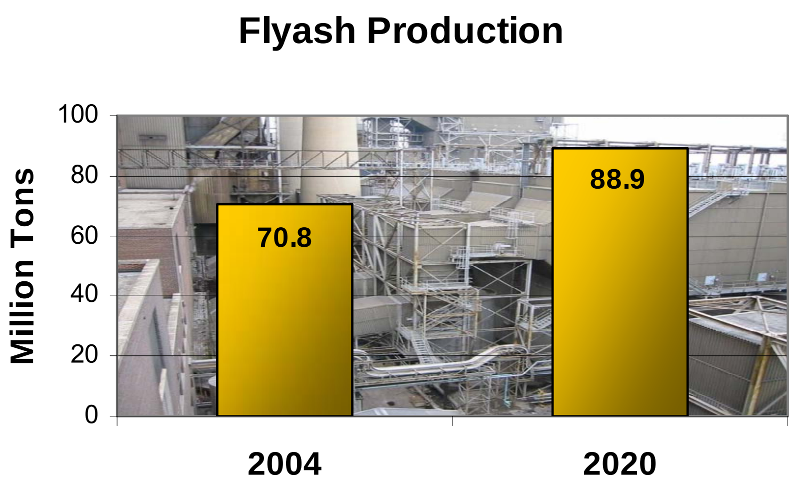
- Installation of additional FGD to meet CAIR (SO_2) will increase volume of scrubber solids
- Installation of additional advanced combustion technology and SCR to meet CAIR (NOx) will increase UBC and NH_3 in fly ash
- Use of PAC injection for Hg control could negatively impact fly ash utilization due to increased carbon content

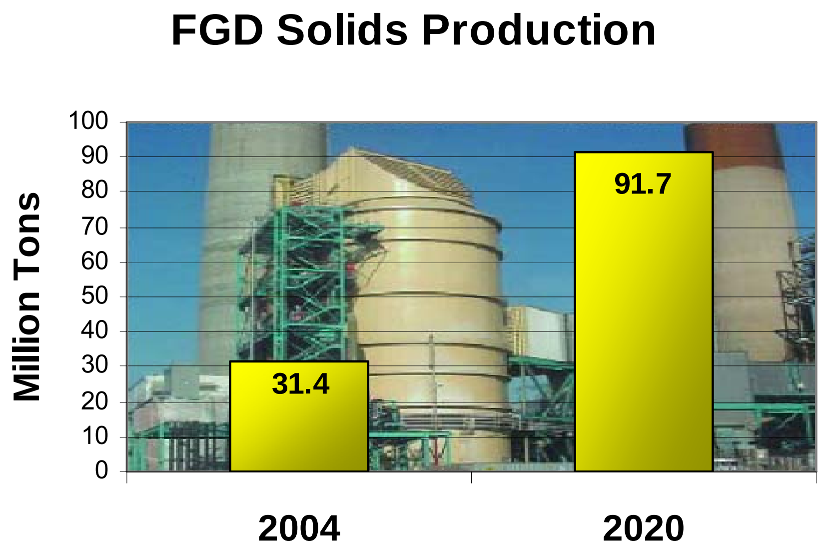


- Increased public scrutiny of CUBs due to transfer of Hg from flue gas to fly ash and scrubber solids

Projection of U.S. Coal-Fired Power Plant CUB Production

Coal-fired power generation projected to increase from 1,916 to 2,405 billion kWh from 2004 to 2020



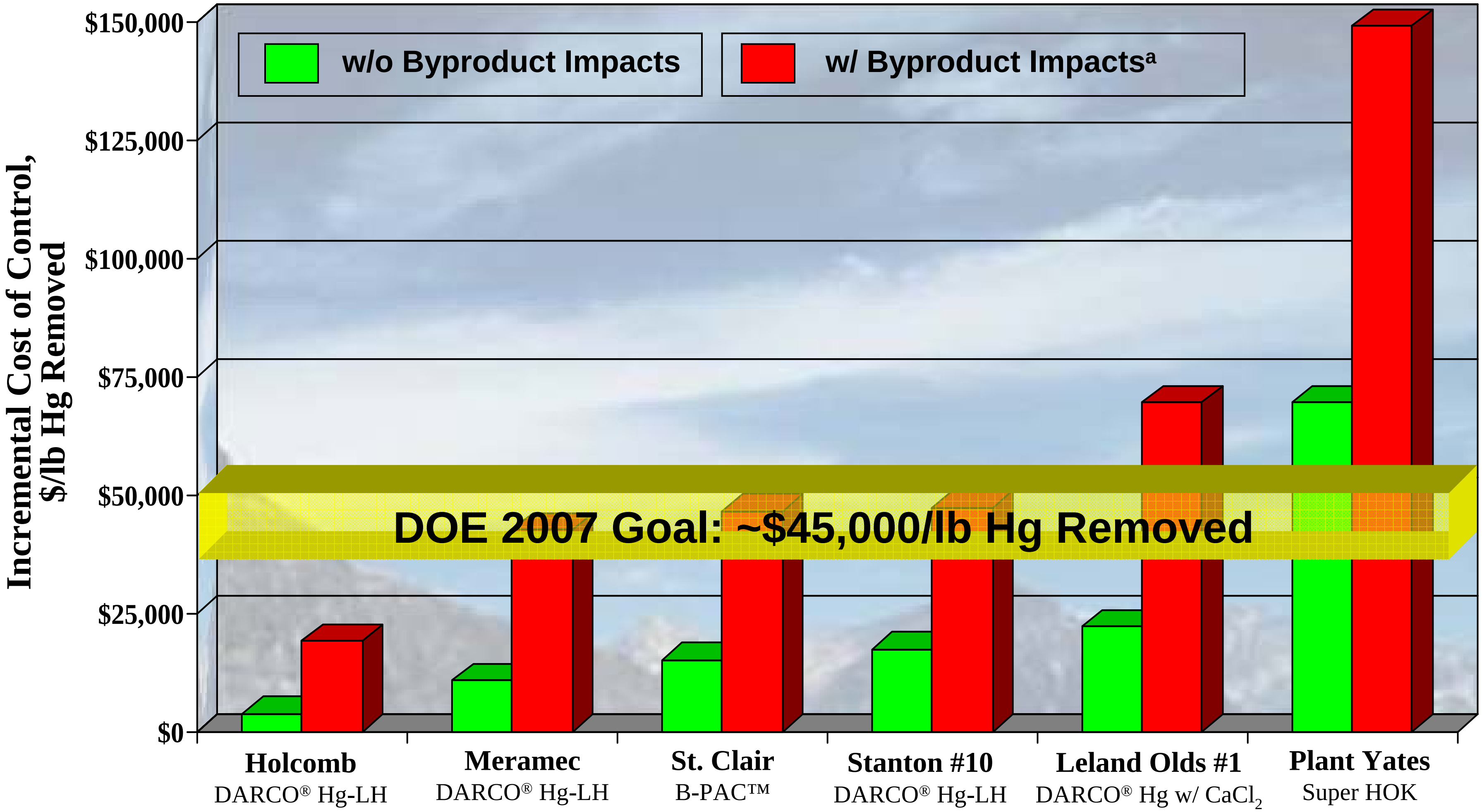


FGD capacity projected to increase from 100 to 231 GW from 2004 to 2020

Sources: ACAA, EIA AEO 2006, and EPA IPM Analysis for CAMR/CAIR

FGD Gypsum: Pathways for Potential Mercury Release

Incremental Cost of 70% ACI Mercury Control



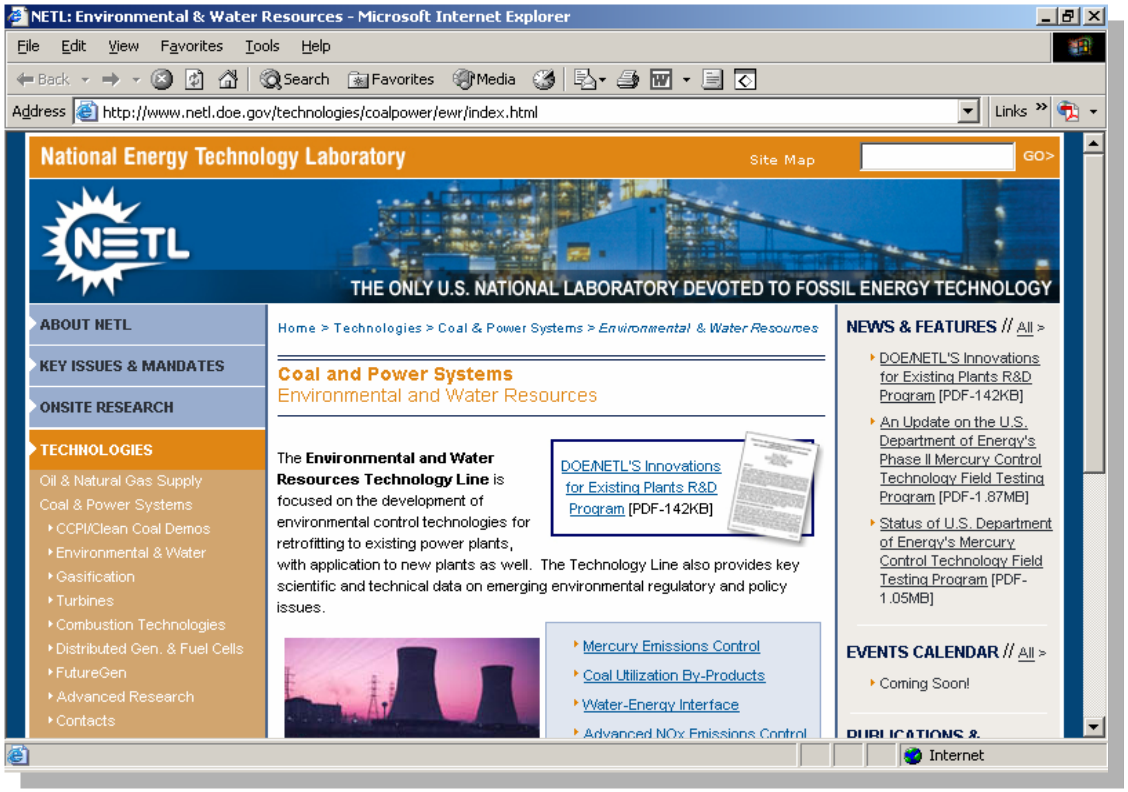
[a] For units equipped with CS-ESP, byproduct impacts include the fly ash disposal cost ($17/ton) and lost revenue from fly ash sales ($18/ton) assuming 100% utilization. For the SDA/FF configuration, only the cost of SDA byproduct disposal is included.

Key Takeaways from Field Testing

- **Halogenated activated carbon and halogen-based additives have shown to be effective in capturing elemental Hg from low-rank coals with both ESP and fabric filters**
- **Estimated cost of Hg control on a $/lb removed basis continues to decline under "no by-product impact" scenario**
- **SCR combined with wet- or dry-scrubbing systems can provide high (~80%-95%) Hg removal with bituminous coals – re-emissions may decrease total Hg capture; uncertainty remains with low-rank coals**
- **Further long-term field testing is needed to bring technologies to commercial-demonstration readiness, particularly related to potential BOP issues and impacts of sulfur/SO_3 and small SCA ESP on ACI effectiveness**
- **Potential coal combustion byproduct impacts on cost of mercury control remain a "wild card"**
- **DOE's RD&D model projects broad commercial availability in 2012-2015**

NETL

DOE/NETL Environmental and Water Resources (Innovations for Existing Plants Program)



To find out more about DOE/NETL's Hg R&D activities visit us at:
http://www.netl.doe.gov/technologies/coalpower/ewr/index.html

ATTACHMENT 4

TO

TESTIMONY OF DIANNA TICKNER

Akira Takano
<Akira.Takano@hal.hitachi.com>
03/23/2006 07:26 AM

To
William.G.Upham@fluor.com, Kent.Jenkins@fluor.com, Clinton.Smith@fluor.com

cc
taiji.yoshida.ut@hitachi.com, Seiichi Kazama <Seiichi.Kazama@hal.hitachi.com>, William Buffa <William.Buffa@hal.hitachi.com>, Takanori Nakamoto <Takanori.Nakamoto@hal.hitachi.com>, kawamura hironobu <kawamura-h@kure.bhk.co.jp>

subject
PSEC Response to Hg 90% removal guarantee request

Clinton and Bill,

Please find the attached official response on the captioned issue.

Best regards,
Rocky
HITACHI POWER SYSTEMS AMERICA
Always for your best solution
Akira(Rocky)Takano
Tel : 908-605-2745
Cell: 914-837-7487(See attached file: Hitachi Response(Hg Removal 90%) 032306.doc)

HITACHI
Inspire the Next

March 23, 2006

Fluor Enterprises, Inc.
100 Fluor Daniel Drive
Greenville, SC 29607-2770

Attn: Mr.Clinton Smith/Senior Project Director
Cc: Mr.Bill Upham/Material Procurement Director
Mr.Kent Jenkins/Project Engineer

Re: Prairie State Energy Campus Hitachi Response (Hg 90% Removal)

Dear Clinton,

Per your request, we confirm our position on your request of Hg 90% removal guarantee as follows:

Since 90% removal of Hg is way beyond the market guarantee level and nobody has such proven experience with this coal for the large capacity power plant, Hitachi will never be in a position to provide such guarantee even if Owner can provide us with the significant additional cost. Apparently, this is not the cost issue but the company policy as a technology background entity. We would appreciate your understanding.

However, we acknowledge the potential application of 90% Hg removal emission in the state of Illinois and Owner's deep concerns on such critical issue for plant operation. Therefore, we have provided the cost impact of Hg 90% removal level (Expected Only) as an option for Owner's selection. We would like to continue to support the project together with Fluor with this approach. This is the best we can contribute to the project as an equipment supplier.

We all together with our subvendors who have been supporting the project are hoping that the project would move forward in our preferable and timely manner.

Sincerely,

Rocky Takano
Proposal Manager
Hitachi Power Systems America

CERTIFICATE OF SERVICE

I, Mary Frontczak, certify that I served electronically the attached APPEARANCE OF MARY FRONTCZAK and TESTIMONY OF DIANNA TICKNER upon the following this 28th day of July, 2006:

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

Marie E. Tipsord
Hearing Officer
Illinois Pollution Control Board
James R. Thompson Center
100 W. Randolph, 100 W. Randolph
Chicago, Illinois 60601-3218
tipsorm@ipcb.state.il.us

Gina Roccaforte, Assistant Counsel
Charles E. Matoesian, Assistant Counsel
John J. Kim, Managing Attorney
Air Regulatory Unit
Division of Legal Counsel
Illinois Environmental Protection Agency
1021 North Grand Avenue, East
P.O. Box 19726
Springfield, Illinois 62794-9276
john.kim@epa.state.il.us
charles.matoesian@epa.state.il.us
gina.roccaforte@epa.state.il.us

and electronically and by first-class mail with postage prepaid and affixed thereon to the persons listed on the **ATTACHED SERVICE LIST**.

__[s] Mary Frontczak__________________

DATED: July 28, 2006

Mary Frontczak
Reg. No. 6209264
Peabody Energy
701 Market Street
St. Louis, Missouri 63101-1826
(314) 342-7810

SERVICE LIST
(R06-25)

William A. Murray
Special Assistant Corporation Counsel
Office of Public Utilities
800 East Monroe
Springfield, Illinois 62757
bmurray@cwlp.com

N. Ladonna Driver
Katherine D. Hodge
Hodge Dwyer Zeman
3150 Roland Avenue, P.O. Box 5776
Springfield, Illinois 62705-5776
nldriver@hdzlaw.com

Christopher W. Newcomb
Karaganis, White & Mage, Ltd.
414 North Orleans Street, Suite 810
Chicago, Illinois 60610
cnewcomb@k-w.com

Bill S. Forcade
Katherine M. Rahill
Jenner & Block
One IBM Plaza, 40th Floor
Chicago, Illinois 60611
bforcade@jenner.com
krahill@jenner.com

Faith E. Bugel
Howard A. Lerner
Meleah Geertsma
Environmental Law and Policy Center
35 East Wacker Drive, Suite 1300
Chicago, Illinois 60601
fbugel@elpc.org

Keith I. Harley
Chicago Legal Clinic
205 West Monroe Street, 4th Floor
Chicago, Illinois 60606
kharley@kentlaw.edu

David Rieser
Jeremy R. Hojnicki
James T. Harrington
McGuire Woods LLP
77 West Wacker, Suite 4100
Chicago, Illinois 60601
drieser@mcguirewoods.com
jharrington@mcguirewoods.com

S. David Farris
Manager, Environmental, Health and Safety
Office of Public Utilities, City of Springfield
201 East Lake Shore Drive
Springfield, Illinois 62757
dfarris@cwlp.com

Bruce Nilles
Sierra Club
122 West Washington Avenue, Suite 830
Madison, Wisconsin 53703
bruce.nilles@sierraclub.org

SERVICE LIST
(R06-25)

Sheldon A. Zabel Kathleen C. Bassi Stephen J. Bonebrake Joshua R. More Glenna L. Gilbert Schiff Harden, LLP 6600 Sears Tower 233 South Wacker Drive Chicago, Illinois 60606 szabel@schiffhardin.com kbassi@schiffhardin.com sbonebrake@schiffhardin.com jmore@schiffhardin.com ggilbert@schiffhardin.com	James W. Ingram Senior Corporate Counsel Dynegy Midwest Generation, Inc. 1000 Louisiana St., Suite 5800 Houston, Texas 77002 Jim.Ingram@dynegy.com