BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
AMENDMENTS TO 35 ILL.ADM.CODE 225:	)	
CONTROL OF EMISSIONS FROM LARGE	)	
COMBUSIONS SOURCES (MERCURY	)	**R09-10**
MONITORING)	)	**(Rulemaking – Air)**
	)	
	)	
	)	

NOTICE OF FILING

To:

John Therriault, Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
Suite 11-500
100 West Randolph
Chicago, Illinois 60601

Persons on the Attached Service List

PLEASE TAKE NOTICE that we have today electronically filed with the Office of the Clerk of the Pollution Control Board **Testimony of Aric D. Diericx On Behalf of Dynegy Midwest Generation, Inc.**, copies of which are herewith served upon you.

Joshua R. More

Dated: February 2, 2009

Joshua R. More
SCHIFF HARDIN, LLP
6600 Sears Tower
233 South Wacker Drive
Chicago, Illinois 60606
312-258-5500

CERTIFICATE OF SERVICE

I, the undersigned, certify that on this 2nd day of February, 2009, I have served electronically the attached **Testimony of Aric D. Diericx On Behalf of Dynegy Midwest Generation, Inc.**, upon the following persons:

John Therriault, Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
Suite 11-500
100 West Randolph
Chicago, Illinois 60601

and electronically and by first class mail, postage affixed, upon persons on the attached Service List.

Joshua R. More

Joshua R. More
SCHIFF HARDIN, LLP
6600 Sears Tower
233 South Wacker Drive
Chicago, Illinois 60606
312-258-5500

SERVICE LIST
(R09-10)

Timothy Fox
Hearing Officer
Illinois Pollution Control Board
100 West Randolph, Suite 11-500
Chicago, Illinois 60601
foxt@ipcb.state.il.us

John J. Kim
Charles E. Matoesian
Dana Vetterhoffer
Division of Legal Counsel
Illinois Environmental Protection Agency
1021 North Grand Avenue, East
P.O. Box 19276
Springfield, Illinois 62794-9276
john.j.kim@illinois.gov
charles.matoesian@illinois.gov
dana.vetterhoffer@illinois.gov

S. David Farris, Manager, Environmental, Health and Safety
City of Springfield, City Water Light & Power
201 East Lake Shore Drive
Springfield, Illinois 62757
dfarris@cwlp.com

David Rieser
McGuireWoods LLP
77 W. Wacker Drive, Suite 4100
Chicago, Illinois 60601
drieser@mcguirewoods.com

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
AMENDMENTS TO 35 ILL.ADM.CODE 225:	)	**R09-10**
CONTROL OF EMISSIONS FROM LARGE	)	**(Rulemaking – Air)**
COMBUSTION SOURCES (MERCURY	)	
MONITORING)	)	

TESTIMONY OF ARIC D. DIERICX
ON BEHALF OF DYNEGY MIDWEST GENERATION, INC.

My name is Aric Diericx. I am testifying on behalf of Dynegy Midwest Generation, Inc. While Dynegy supports the Illinois Environmental Protection Agency's ("Agency") stated objective of incorporating the monitoring portions of the vacated Clean Air Mercury Rule ("CAMR") into the Illinois mercury rule, Dynegy has several concerns with the Agency's proposed amendments in this rulemaking that go beyond the requirements of the CAMR monitoring provisions. Dynegy is concerned with the Agency's position regarding "optimum manner" as that term is used in Section 225.233(c)(2) of the currently effective Illinois mercury rule and the retrospective noncompliance exposure presented by proposed Section 225.239(g)(2). Additionally, Dynegy requests clarity on a couple of issues and supports an alternative mercury emission reduction calculation methodology.

I am the Senior Director-Operations Environmental Compliance for Dynegy's Midwest Region. The Midwest Region has generating facilities in Illinois, Michigan, Pennsylvania, and Kentucky. The Midwest Region also provides environmental compliance support for a new coal plant under construction in Arkansas. I have been employed in this and similar positions at Dynegy for the past eight years. As part of my duties at Dynegy, I oversee permitting and regulatory development and compliance for air, water, and waste issues. Previously, I was employed by Illinois Power Company since 1979 in its environmental department. Illinois Power and Dynegy merged in 1999/2000.

I received a Bachelor of Science degree in meteorology from Northern Illinois University in DeKalb, Illinois, in 1979. I have 29 years of experience in environmental compliance, primarily with air quality programs, including New Source Review, the Acid Rain Program, and Title V permitting. I have supervised the development of ambient air quality monitoring programs, the development of a site-specific dispersion model, and Illinois Power's State Implementation Plan revision for sulfur dioxide ("SO_2"). I was involved in the studies of the Ozone Transport Assessment Group and the subsequent development of the NOx SIP Call Rule in Illinois (Part 217, Subpart W of the Board's rules), as well as the state's Part 225 mercury emissions rulemaking. I have served as chairman of the Midwest Ozone Group and the Air Utility Group of Illinois. I am knowledgeable about Dynegy's air quality compliance programs and the efforts that would be required to comply with the proposed changes to the Illinois mercury rule.

Dynegy owns and operates five coal-fired power plants in Illinois that are affected by this proposed rulemaking. These are the Baldwin Energy Complex located in Randolph County, the Havana Power Station located in Mason County, the Hennepin Power Station located in Putnam County, the Vermilion Power Station located in Vermilion County, and the Wood River Power Station located in Madison County. These five power plants account for approximately 3,375 gross megawatts of generation, accounting for around 21% of the total installed coal-fired generating capacity in the state.

Optimum Manner

Dynegy has reviewed Mr. Scott Miller's testimony on behalf of Midwest Generation on this topic and adopts the same position. To ensure clarity, I note that Mr. Miller referred to Section 225.294 in the Combined Pollutant Standard ("CPS") regarding the requirement that halogenated activated carbon or sorbent be injected in an optimum manner. Similar language appears in the Multi-Pollutant Standard ("MPS") at Section 225.233(c)(2). Dynegy opted in to the MPS on November 26, 2007. Dynegy's decision to opt in to the MPS was based on the plain language of the MPS that afforded Dynegy relief until 2015 (or such earlier date that Dynegy determined that a unit should become subject to the percent reduction emission limit) from the requirement to reduce mercury emissions to any set level of reduction or even approximation of any particular level of reduction so long as Dynegy injected one of the listed sorbents at a rate of 5 lbs/macf[1] using an injection system designed for effective absorption of mercury in the flue gas considering the configuration of the electric generating unit ("EGU") and its ductwork. In addition, the plain language of the mercury rule limited Dynegy's MPS units to routine monitoring of the feed rate of sorbent injection and the exhaust gas flow rate

The MPS requires sources to "inject [sorbent] in an optimum manner" using "an injection system designed for effective absorption of mercury," including the requirements for a minimum injection rate and sorbent products from specific manufacturers. The designs of Dynegy's sorbent injection systems were included in its construction permit applications that were approved by the Agency when it issued the construction permits for our sorbent injection systems.

[1] The injection rate of 5 lbs/macf is required if the unit burns subbituminous coal. The injection rate of 2.5 lbs/macf applies for cyclone-fired EGUs that will install a scrubber and baghouse by December 31, 2012, and already meet an emission rate of 0.020 lb Hg/GWh or at least 75% reduction. *See* Section 225.233(c)(2)(C).

Dynegy opted in to the MPS in 2007 based on its review and assessment of the original MPS requirements. Dynegy's understanding of the original rule was confirmed by the Agency's testimony acknowledging that "optimum manner" is defined in the mercury rule and that the definition does not specify a percent reduction in mercury emissions. Tr. 51-52, R09-10, Dec. 17, 2008. Dynegy has already committed to comply with the specific set of MPS requirements as they appeared in the originally promulgated rule and the Agency-issued construction permits. Since Dynegy is already locked in to MPS participation, it urges the Board to reject any attempt to expand the MPS rule to include mercury removal efficiency in a re-definition of "optimum manner" or as a factor in determining compliance with the MPS rule.

Retrospective Noncompliance Under Proposed Section 225.239(g)(2)

Dynegy generally supports the Agency's proposal to include the stack testing option at Section 225.239. However, the retrospective noncompliance established in Section 225.239(g)(2) – that is, noncompliance determined through a stack test dates back to the last compliant stack test – is inconsistent with general practice regarding reliance on stack testing to demonstrate compliance with a standard. While mercury stack testing will not be the compliance method for Dynegy's MPS units complying with the sorbent injection requirement, it is an option for any unit that Dynegy may move in to the percent reduction portion of the rule prior to 2015. Dynegy will move an MPS unit in to the percent reduction portion of the rule only if it expects that the unit can maintain compliance with that portion of the rule. The retrospective method of determining compliance proposed by the Agency creates a substantial noncompliance risk that will likely force Dynegy to rely upon other monitoring methods that are either more labor intensive or could create monitor data unavailability problems. Thus, Dynegy requests that the Board revise this section to provide that noncompliance is prospective – from the noncompliant stack test to the next compliant stack test.

Using stack test results to determine noncompliance prospectively is standard practice. For example, a stack test for particulate matter ("PM") determines compliance at the time of the stack test and continued operation under the conditions tested are also presumed compliant. If the next stack test for PM does not comply, then the unit is out of compliance until a compliant stack test is performed, not back to the first stack test. Mercury stack testing should be treated no differently.

A prospective noncompliance policy, initiated at the time of a failed stack test, would provide clear and immediate notice to the company to check for sorbent injection problems. Since initial mercury stack test results can be provided on the same day the tests are performed, the company could take prompt action to correct any operations problems and avoid causing noncompliance with the 12-month rolling average mercury limit. A retrospective approach would likely sentence a company without any prior notice to three months or longer of noncompliance with the mercury limit whenever it failed a stack test.

Another part of the Agency's proposed rule, Section 225.239(i)(2), would require the development of parametrics during stack testing that would be monitored during the period between stack tests to ensure compliance. The purpose of the parametric monitoring, to ensure that the unit continues to operate in a manner consistent with its operation during the compliant stack test, is a reasonable supplement to periodic mercury stack tests. However, the premise of parametric monitoring is negated if the regulations then mandate that a subsequent noncompliant stack test subjects the unit to noncompliance back to the prior stack test despite compliance with the parametrics. Indeed, the company would have no notice of potential noncompliance and no chance to change operations or to re-test at an earlier date in order to avoid or shorten the period of noncompliance. This lack of notice and the risk of incurring substantial penalties for long-term noncompliance are major flaws in proposed Section 225.239(g)(2) that could preclude EGUs from ever using this section.

Moreover, retrospective noncompliance is inconsistent with other parts of the stack testing provision. The proposed rule provides that stack testing must be performed if there is a significant change at a unit between the normal quarterly or semi-annual tests, such as a switch from bituminous to subbituminous coal. While a noncompliant stack test with the new coal may indicate a recent problem, there is no indication of noncompliance back to the date of the compliant stack test with the prior coal. Assuming noncompliance back to the prior stack test, as required by the Agency's proposed rule, ignores all other circumstances during the interim period.

The Agency's proposed approach would create an environment of uncertainty concerning the value of a compliant stack test and how often stack testing should be performed in order for companies to reduce their exposure to enforcement. Dynegy urges the Board to delete the retrospective noncompliance elements of proposed Section 225.239 from the rule.

Flue Gas Temperature Correction Required by Section 225.233(c)(2)

Dynegy understands that the Agency has agreed to amend the methodology for correction of the flue gas temperature so that if there is a difference between the temperature of the stack and the temperature at the point of sorbent injection, it will not increase the pounds of sorbent required to be injected on an hourly basis. Dynegy supports changes to the Agency's proposal that will result in a rule with the same intent as the following:

Section 225.233(c)(2):

D) For the purposes of subsection (c)(2)(C) of this Section, the flue gas flow rate ~~must~~ may be determined ~~for~~at the point of sorbent injection or~~; provided 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 the flue gas flow rate may otherwise be calculated from the stack flow rate, corrected for the difference in gas temperatures~~.

Use of "Excepted" in Sections 225.234(a)(4), 225.238(a)(4), and 225.239(a)(1), (3), and (4)

Dynegy notes that the Agency has used the word *excepted* in Sections 225.234(a)(4), 225.238(a)(4), and 225.239(a)(1), (3), and (4) and elsewhere in a manner inconsistent with its dictionary definition. We believe that the intent is that the use of sorbent traps is an approved and acceptable means of monitoring mercury. We request that the Board specifically clarify that this is the intent of the use of the word *excepted* or that the word be changed to *accepted*.

Mercury Emission Reduction Calculation Procedures

Dynegy has reviewed the Agency's proposed methodology for calculating mercury emission reductions and suggests that the Board allow for an alternative calculation methodology, at least for sources using sorbent trap sampling systems. This alternative method is to demonstrate compliance on a lb/TBtu basis rather than the current mass basis of pounds mercury in v. pounds mercury out. The equations reflecting this alternative approach and justifications for these calculations are set forth in Attachment 1 to my testimony, a memorandum from Steve Norfleet at RMG Consulting & Research, Inc., to Wendell Watson at Dynegy.

This lb/TBtu approach is simpler than the calculation requirements included in the Illinois mercury rule and avoids the problems caused by missing data. It is simpler because stack flow and coal scale data are not required to perform the calculations, and eliminating those items also eliminates the bias or error of those systems from the calculations. Since the lb/TBtu approach is similar to the lb/MBtu method used to determining control device removal efficiency in conjunction with federal New Source Performance Standards, it provides consistency with an existing USEPA methodology. The addition of this calculation would provide sources with a straightforward alternative to determine their mercury removal efficiency.

Conclusion

Dynegy urges the Board to reject any attempt to change the scope of the MPS with a new definition of "optimum manner," implemented at least in part through the proposed requirement in Section 225.265(b) that all MPS units sample coal for the express purpose of using that data as the sole compliance indicator for MPS units. Dynegy also urges the Board to reject the Agency's proposed retrospective noncompliance in the new stack testing provisions, Section 225.239(g)(2). Dynegy requests that the Board amend the provision requiring correction to the stack flow where the temperature at that point is greater than 100°F difference from the point of sorbent injection. Dynegy requests that the Board clarify the meaning of the word *excepted* as the Agency has applied it to sorbent traps. Finally, Dynegy supports an alternative mercury emission reduction calculation methodology at least for sources using sorbent trap sampling systems.

I would be happy to answer any questions.

Attachment 1

RMB Consulting & Research, Inc.

5104 Bur Oak Circle
Raleigh, North Carolina 27612

Phone: (919) 510-5102
Fax: (919) 510-5104

Technical Memorandum

To: Wendell Watson, Dynegy
From: Steve Norfleet, RMB
Date: January 29, 2009

Re: Mercury Emission Reduction Calculation Procedures

The mercury control requirements within Part 225 of Illinois Administrative Code (IAC) Title 35 allow sources to demonstrate compliance by showing a 90% reduction on 12-month rolling average basis. However, the rule specifies that the reductions should be calculated based on a mass basis (pounds in vs. pounds out), which unnecessarily complicates the determination. Dynegy should petition the Illinois Pollution Control Board (IPCB) to allow it to demonstrate compliance instead by calculating the reductions on a lb/TBtu basis. While providing equivalent results, the lb/TBtu approach is simpler to implement and avoids some of the potential issues presented by the vacature of the Part 75 mercury monitoring provisions.

Background Information

Beginning on July 1, 2009, Section 225.230 of IAC Title 35 states that existing affected sources must demonstrate compliance with either an output-based standard of 0.0080 lb mercury/GWh or show a minimum 90% removal of mercury emissions on a rolling 12-month basis. For sources electing to show compliance with the 90% removal limit, the rule indicates that the emissions should be calculated using the following formula:

$$CE = 100 \times \{1 - (\sum_{i=1}^{12} E_i \div \sum_{i=1}^{12} I_i)\}$$

Where:

CE	=	Actual control efficiency for mercury emissions of the EGU for the particular 12-month rolling period, expressed as a percent.
E_i	=	Actual mercury emissions of the EGU, in lbs, in an individual month in the 12-month rolling period, as determined in accordance with the emissions monitoring provisions of this Subpart B.
I_i	=	Amount of mercury in the fuel fired in the EGU, in lbs, in an individual month in the 12-month rolling period, as determined in accordance with Section 225.265 of this Subpart B.

There are, however, a number of issues with implementing this provision. First the D. C. Circuit Court of Appeals vacated the clean air mercury rule in its entirety, including the 40 CFR Part 75 mercury monitoring provisions referenced in the Part 225 of the IAC. Not only does the absence of the Part 75 monitoring requirements create a regulatory void, but these provisions included procedures that were incompatible with accepted compliance determination fundamentals.

Second, while §225.265 of Subpart B does specify sampling and analysis for determining coal mercury concentrations in lb/TBtu, it does not indicate how one should convert these concentration values mass (lb) values. Finally, the procedure is inconsistent with other emission removal efficiency calculations, which are generally performed on a lb/mmBtu-basis.

Recommended Approach

In lieu of a mass-based removal efficiency determination, I recommend that reduction be calculated based the average coal and flue gas lb/TBtu concentrations for the applicable 12-month rolling period. The equation in Section 225.230(a)(3) could be revised as follows:

$$CE = 100 \times \left(1 - \frac{E_{avg12}}{I_{avg12}} \right)$$

Where:

CE	=	Actual control effieiency for mercury emissions of the EGU for the partieular 12-month rolling period, expressed as a pereent.
E_{avg12}	=	Average mereury emissions of the EGU, expressed in lb/TBtu, for the 12-month rolling period, as determined in accordance with the emissions monitoring provisions of this Subpart B.
I_{avg12}	=	Amount of mercury in the fuel fired in the EGU, expressed in lb/TBtu, for the 12-month rolling period, as determined in accordance with Section 225.265 of this Subpart B.

The preceding equation takes the same form as the Equation 19-23 (and Equation 19-12) in Method 19 of Appendix A in 40 CFR Part 60, which is used to determine control device removal efficiency based on lb/mmBtu concentrations[1] in conjunction with the federal New Source Performance Standards (e.g., SO_2 removal efficiency for utility units under Subpart Da of Part 60).

The approach is also mathematically equivalent to the mass-based approach as demonstrated by the exercise below:

$$CE = 100 \times \left(1 - \frac{Hg\ Mass_{Emissions}}{Hg\ Mass_{Coal}} \right) = 100 \times \left(1 - \frac{lb/TBtu_{Emissions} \times Heat\ Input}{lb/TBtu_{Coal} \times Heat\ Input} \right) = 100 \times \left(1 - \frac{lb/TBtu_{Emissions}}{lb/TBtu_{Coal}} \right)$$

The total mass of the mercury in the coal and the total flue gas mass emissions are simply a function of the concentration (in lb/TBtu) times the heat input (in TBtu). In this expanded form, the heat input in the numerator and the denominator cancel out, leaving only the ratio of the lb/TBtu concentrations. The ratio expresses the same underlying relationship but in a more direct, basic form.

While equivalent, the lb/TBtu approach provides significant benefit. Foremost, it is simpler. Stack flow and/or coal scale data would be needed to calculate mass values but are not necessary under the lb/TBtu the approach. Thus, any bias or error (and potential monitor downtime) that

[1] While emission rates such as SO_2 or NO_X are often expressed in lb/mmBtu (or $1b/10^6$ Btu), mercury emissions are often expressed in terms of lb/TBtu (or $1b/10^{12}$ Btu) because of thc ultralow concentration levels.

might have been associated with the introduction in the stack flow or coal scale measurements has been circumnavigated.

The approach also affords a resolution to the potentially messy issue of missing data. Every monitoring system will experience downtime due to periodic maintenance, quality assurance activities, and unforeseen events/failure. If one determines efficiency from mass values, then the question of how to fill in the missing periods can be important. The proposed Part 75 mercury rule included schemes for replacing missing data with conservative values. However, while one might argue the merits of this technique for the proposed national mass emission trading program, missing data substitution has no place in compliance determination under a command and control requirement. It is arbitrary to assess compliance in the absence of data based on made up values. For example, echoing this point, Subpart Da allows the use of Part 75 monitoring data but specifically prohibits the use of Part 75 missing data or bias adjustment factors.

In contrast, missing data need not be an issue if the lb/TBtu approach is used. The average mercury emissions (E_{avg12}) can be calculated based on all the available valid hourly emissions data for the rolling 12-month period. Likewise, the average coal concentration (I_{avg12}) can be calculated based on all the available valid coal data for the rolling 12-month period. Having some monitor downtime is a fact of life but it does not diminish the use of the remaining data. For example, for most existing units under Subpart Da, a 30-day SO_2 average is deemed acceptable as long as there are a minimum of 18 hours in at least 22 of 30 successive boiler operating days and, for new units, a monthly mercury average is considered viable as long as the monitor availability is 75% or greater. While there may be a fraction of monitor downtime, the vast majority of hours will be valid. Over a 12-month period, the average concentrations will be representative and should provide reasonable percent mercury reduction values.