BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
PROPOSED NEW 35 ILL. ADM. CODE 225	)	R06-25
CONTROL OF EMISSIONS FROM LARGE	)	(Rulemaking – Air)
COMBUSTION SOURCES	)	
35 Ill. Adm. Code 225.100, 200	)	
	)	
	)	

NOTICE OF FILING

TO: Those Individuals as Listed on attached Certificate of Service

Please take notice that on June 2, 2006, the undersigned caused to be filed with the Clerk of the Illinois Pollution Control Board the attached **PRE-FILED QUESTIONS OF JAMES STAUDT** as listed below, a copy of which is herewith served upon you:

Dated this 2nd day of June, 2006.

Respectfully submitted,

AMEREN ENERGY GENERATING COMPANY
AMERENENERGY RESOURCES GENERATING COMPANY
ELECTRIC ENERGY, INC.

By: James T. Harrington
One of its Attorneys

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CERTIFICATE OF SERVICE

The undersigned, one of the attorneys for Petitioners, hereby certify that I served a copy of the attached **PRE-FILED QUESTIONS OF JAMES STAUDT** as listed above upon those listed below on June 2, 2006 via First Class Mail, postage prepaid.

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CLERK'S OFFICE
JUN 0 2 2006
STATE OF ILLINOIS
Pollution Control Board

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IN THE MATTER OF:	)	
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PROPOSED NEW 35 ILL. ADM. CODE	)	R06-25
225 CONTROL OF EMISSIONS FROM	)	(Rulemaking – Air)
LARGE COMBUSTION SOURCES	)	
35 Ill. Adm. Code 225.100, 200	)	
	)	
	)	

QUESTIONS FOR JAMES E. STAUDT Ph.D.
BASED UPON ORIGINAL FILED TESTIMONY

1. Please describe your personal experience in the design, construction, and installation in major pollution control projects at coal fired electric power plants.

2. Prior to preparing your written testimony in this proceeding and your work on the technical support document, did you perform a detailed study of the existing coal fired power plants in the State of Illinois?

3. Were you familiar with the size and design of the electrostatic precipitators used on each of these facilities?

4. Is it not true that ESPs at Illinois facilities are typically much smaller than those in various studies referred to in the TSD?

5. Were you familiar with the gas conditioning that is used on some of these facilities?

6. How familiar were you with the sources and chemical compositions of the coals that were consumed at these power plants, including the amount and types of mercury in the coals used at these plants?

7. Did you review engineering plans or drawings on these plants to determine the feasible locations for installing the types of technology recommended in your testimony and whether it would provide adequate reaction time prior the ESPs?

8. Over the last five years, how much of your work has been done directly for the operators of coal fired electrical generating units?

9. How much of your work has been done for the suppliers of pollution control equipment and pollution control supplies, such as sorbents?

10. Are there any other professionals with Andover technologies other than yourself?

11. Has or does Andover Technologies do work for a company called Sorbent Technologies Corporation?

12. How much of your work is done for them?

13. How much of Andover Technologies' work is done directly for the operators of coal fired electrical generating units?

14. How much of Chapter 8 of the technical support document were you responsible for writing?

15. Did you prepare all the tables in Chapter 8?

16. Did you calculate the costs due to the impact of activated carbon injection on ash disposal?

17. Did you do the calculations in each of the tables in which it is referenced in the TSD?

18. With reference to the technical support document at page 115, it states "effective capture in the range of about 90% appears to occur for all types of FGD when SCR is used in combination with FGD." Is this intended to imply that such applications will consistently achieve over 90% removal so to comply with the Illinois rule?

19. At page 119 of the technical support document, it states "Some of the bituminous coal fired boilers may not achieve adequately low mercury emissions by co-benefits alone. Therefore, these plants may need additional controls to achieve the levels of mercury removal that are being required in the proposed rule." Which if any Illinois plants do you believe would require additional controls to comply with the rule of mercury removal beyond flue gas desulfurization and selective catalytic reduction?

20. What additional controls would be required?

21. Table 8.9 indicates that Duck Creek, Dallman and Marion would achieve compliance with the Illinois rule through "co-benefit." On what do you base that statement?

22. Have you reviewed the data with respect to Duck Creek, Dallman and Marion to reach a professional conclusion that co-benefit alone will be sufficient to achieve compliance with the proposed Illinois regulation?

23. If that statement is not correct, should there not be costs associated with additional controls that may be required?

24. At page 118 of the technical support document, it states that what FGD additives are successful in improving mercury removal and by implication achieving compliance with the Illinois regulation. At what facilities has this been demonstrated?

25. With respect to injection of halogenated activated carbon, we call your attention to Figure 8.10 of the technical support document. Does that demonstrate that removal at or about 90% with some below and some slightly above was achieved for halogenated activated carbon injection prior to the ESPs? Were not all of those tests based on a 30 day period?

26. How can one project an average of over 90% removal based on 30 day tests which did not demonstrate that level of removal?

27. At pages 127 and 128 of the technical support document, it states "The Allen plant is a low-sulfur coal application and Lausche Plant has a higher sulfur coal (although not as high a sulfur level as in most bituminous coals fired in Illinois). As shown, 90% removal is approached at injection rates of 7 lb/MMacf. There is currently no test data on units with sulfur levels as high as those of Illinois coals." How do these results support a requirement for over 90% removal from facilities firing high sulfur Illinois coal using halogenated sorbent injection?

28. TOXECON At page 129 of the technical support document, it states "Except on western coals downstream of a Spray Dryer Absorber, PAC (untreated or halogenated) in TOXECON arrangements or fabric filter arrangements is generally accepted to be capable of over 90% removal because the sorbent is in very intimate contact with the gas stream as it passes through the filter cake of the fabric filter." What is the basis for this statement?

29. Has any pilot test been done employing the halogenated activated carbon injection prior to a baghouse called the TOXECON arrangement on western coals that consistently achieved over 90% removal?

30. Based on the statement in the report, are you stating that 90% removal would not be achievable downstream of a Spray Dryer Absorber?

31. At page 129, you reference the Southern Company's Gaston Station. Was not that facility burning bituminous coal?

32. Is not the Presque Isle facility a federally funded test program to determine the effectiveness of the "TOXECON" system?

33. Why is the government funding this test if the technology and its performance are already demonstrated?

34. Is it not true that there is limited data on that system due to a fire in the baghouse?

35. As stated at page 130 of the technical support document, do not the Presque Isle facility costs substantially exceed the model costs relied upon?

36. Were not these costs a result of the layout of the Presque Isle facility, the requirements for structural steel, and mechanical and structural installation?

37. What basis do you have to say that those costs are not typical of retrofit installations on Illinois facilities?

38. Aside from Presque Isle, which is not presently operating, is there any other TOXECON array, i.e., halogenated activated carbon injection prior to a baghouse, in operation on

which reliable data can be obtained whether on western low sulfur coals or bituminous coals?

39. With respect to design issues and with reference to the Gaston Station facility, did not those tests demonstrate the importance of understanding the total particulate load to the baghouse an appropriate design?

40. Section 8.4.5.4 of the technical support document at pages 142 and 143 makes reference to the build up of carbon on duct surfaces. Could not that build up interfere with the operation of the facility?

41. Could not the build up of carbon also occur in the ESP?

42. With a build up of carbon in the ducts and the ESP is there not at an elevated risk of fire in the duct work or ESP?

43. Did you prepare Table 8.1 of the technical support document dealing with "sorbent injection field demonstrations?" Is it correct that of the 41 studies listed there, only nine were on PRB coal?

44. As to each of such demonstrations, state your knowledge at the time your testimony was prepared as to each of the following elements:

    a. The size of the ESP and the length of time of the study;

    b. The maximum, minimum and mean removal rate achieved on each;

    c. The method used for measuring mercury in the emissions;

    d. The method used for measuring mercury in the coal charged to the furnaces;

    e. The length of each study;

    f. The statistical method used to predict/analyze the data resulting from the study and predict future removal rates;

    g. Whether the conditions upon which the study was run are comparable to those conditions that would be expected in a year round operation under normal operating conditions;

    h. As to the Presque Isle study with a "TOXECON" system, please describe the current status of that study and whether there have been any significant problems with the study.

45. Which of these studies do you believe is representative of normal operating conditions on facilities in Illinois, including the size of the ESPs and use of gas conditioning?

46. Did any of these studies run long enough to predict performance under normal operating conditions?

47. When dealing with new technology isn't a minimum of one year of full scale operation necessary to project future performance?

48. You previously stated that SO_3 in flue gases would interfere with mercury removal from halogenated powdered activated carbon. Is that correct?

49. Are you familiar with the use of sulfur tri-oxide as a gas conditioner prior to coal side ESPs where facilities have been converted from high sulfur bituminous coal to low sulfur Powder River Basin coal ("PRB")?

50. Are you familiar with the impact of such treatment on the performance of halogenated activated carbon?

51. What would you expect the impact of such treatment on the performance of halogenated activated carbon to be?

52. How does the size of ESPs on Illinois coal fired power plants compare to those in the studies referred to in the technical support document?

53. How would you expect that to impact mercury removal?

54. Can you state from your own knowledge or based upon information that you have reviewed what the expected mercury removal will be from facilities with ESPs similar in size to those in Illinois and sulfur tri-oxide conditioning following installation of halogenated activated carbon (HAC) injection prior to the ESPs?

55. Can you state what the affect of the smaller ESPs, common in Illinois facilities would be?

56. Is it true that you have no data which to predict mercury removal with HAC injection from smaller ESPs on Illinois coal fired power plants either with or without sulfur tri-oxide conditioning?

57. Based upon your knowledge of the treatment technologies and your familiarity, to the extent you are familiar, with Illinois coal fired power plants, could you advise a client in Illinois to rely upon halogenated activated carbon injection prior to the ESP as a technology to achieve compliance with the proposed Illinois regulation?

58. With reference to page 153 of the technical support document,

    a. Could provide/explain the data and source used for the five year coal use?

    b. Was the coal use projected to a future date? If so, what is the projected year and what where the assumptions used in the projection methodology?

    c. Was the data in Table 8.5 used to estimate the Hg in coal in Table 8.6? If so, our computations yield 170,352 oz. If different data was used, what was the heat and Hg content of the coals used?

59. With reference to page 156 of the technical support document,

a. By unit, what are the coal types (bituminous, sub-bituminous) you are assuming IL units will be burning in 2009?

b. By unit, what are the 2009/10 control configurations (SO2, NOx and PM controls) you are assuming?

c. What is the level of co-benefits are you assuming for the 2009/10 control configurations (in pounds) and the removal efficiencies of these control configurations?

d. Are you assuming that all units, except Waukegan 7 and Will County 3, can achieve 90% mercury removal through ACI?

e. In the analysis of CAMR in 2010, did you employ the Phase I CAMR unit allocations and allow for system-wide trading? Also, are you assuming the most cost-effective method of compliance under CAMR in 2010 is to install control technologies on all but 6 of IL coal units?

60. With reference to page 157 of the technical support document,

a. What is the basis of your statement ".....it is reasonable to say the cost of allowances should be somewhat higher the than the cost in the market for producing allowances."

b. Are not allowance prices based upon the marginal cost of control, not incremental cost of control as displayed in Table 8.19.

61. With reference to page 159 of the technical support document,

a. What is the basis of the statement that "...the 2018 CAMR limit is roughly equal to the requirements with the proposed rule, the incremental cost will be negligible for 2018 compliance."

b. Is it not true that both rules are entirely different from the points of measurement of emissions to required reduction levels, as well as, CAMR is market based (cap & trade) and the IL rule is command-and-control.

62. With reference to page 195 of the technical support document,

a. IL has prepared a projection of Hg emissions from coal-fired EGUs for CAMR from 2010 – 2020. Could you provide the unit specific data for IL EGUs, illustrating the unit name, generation/Btus, control configuration and final mercury emissions by year from 2010 – 2020.

63. Please describe your familiarity with techniques for sampling of coal and deriving a statistically reliable sample for daily mercury content in coal fired boiler.

64. Please describe what type of installation would be necessary to obtain such a sample, what it would cost, and how long would it take to install.

65. Please describe your knowledge of the available continuous emission monitors for mercury and the emissions from a boiler.

66. How precise and accurate are those devices to the best of your knowledge?

67. Are you aware of any pattern of bias in any such device, including those devices most likely to be approved by USEPA?

68. How would the variability of the inlet sampling for the coal charged to the boilers, the variability of continuous emission monitors, and the variability of removal efficiency on a daily/monthly basis impact compliance with the proposed Illinois rule?

69. Earlier, I asked about your familiarity with the design, construction and installation of pollution control equipment. Please describe the variables you expect to deal with in installing halogenated powdered activated carbon at the Illinois facilities.

70. In your estimates of cost, does that include the design and installation of the technology, or only purchase?

71. Would you be surprised if those numbers were twice what you estimated, just for the installation of the sorbent injection systems?

72. How much contact time between the point of sorbent injection and the ESPs is necessary for adequate removal?

73. Do you know how much time or how much before the ESP the sorbent would have to be injected to be effective at the rates you predicted?

74. Assuming that the sorbent technologies were not sufficient to achieve a 90% reduction, would you agree that the "TOXECON" array of sorbent injection followed by a baghouse is the most logical way to achieve those reductions based upon present knowledge and information? If not, please describe what the alternatives would be, how much they would cost, and how long they would take to install.

75. To the best of your knowledge, what is the variability in designing a baghouse?

76. Would not studies need to be performed to determine the particulate emission that it might experience independent of the halogenated activated carbon to be injected?

77. If there was particulate carryover from the ESP, would it not require a larger baghouse?

78. If the baghouse receives significant particulate emissions in addition to powdered activated carbon, would that not affect the design parameters for the baghouse?

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79. If the baghouse received that additional particulate matter, would that have a potential to interfere with or reduce the mercury removal efficiency of the baghouse?

80. What factors would influence the design and capacity of the required fans to operate a baghouse system?

81. How long would it take to determine those variables on typical installation?

82. Are you personally familiar with the layout of some or all of the coal fired electric generating stations in Illinois?

83. Are you familiar with what problems there would be in locating a baghouse at each of the coal fired electrical generating units in Illinois?

84. Will issues relating to locating the baghouse at individual generating stations affect the fan capacity required to move the flue gases from the outlet through the baghouse and back to the stack?

85. Do the fan and baghouse require considerable electrical energy to operate?

86. Have you estimated the electrical demands of such systems on units in Illinois?

87. Have you made an independent determination whether the power transformers and supporting electrical systems are available at the electrical generating units in Illinois?

88. Construction Issues: How many units do you expect to be retrofitted with controls for mercury in the State of Illinois?

89. Assuming that those units require a TOXECON type treatment system, i.e.: injection of halogenated powdered activated carbon after the ESP followed by a baghouse, what is the estimated time for the installation of one such unit?

90. If all of the electrical generating units in the State of Illinois using PRB coal need such an installation, what is the projected time for installation?

91. Based upon knowledge and availability of engineers to perform the necessary field investigations and detailed designs to install "TOXECON" arrays at each unit in Illinois, do you believe all facilities could be designed and built within three years?

92. Do you have personal knowledge of the availability of baghouses in the market today and whether they would be available for installation in the next 36 months for all of the electrical generating units in Illinois using PRB coal?

93. Do you have personal knowledge of the availability of skilled tradesmen necessary for these installations, including industrial electricians, steelworkers, pipefitters, etc.?

94. With respect to the foregoing answers, have you taken into account the other pollution projects that must be ongoing in the Midwest and throughout the country in the same period of time?

95. At the time you originally assisted in preparing the technical support document and prepared your testimony in this proceeding, did you have knowledge of the availability of baghouses, fans, and the necessary engineering and skilled personnel to design, construct, and install such systems?

96. Are you aware of other technologies that are presently being developed for removal of mercury from the flue gas and subbituminous fired electrical generating units?

97. What are those technologies and what is the status of development?

98. Does this include materials sprayed directly on the coal to introduce halogens at that point?

99. When do you expect that these technologies will be commercially available?

100. Some of these technologies have promised to be more effective and less costly than those currently available. Some of these technologies offer the hope of being more compatible with other forms of pollution control that will be required, is that not correct?

101. With respect to all the data on the various tests you have referred to, has statistical analysis been performed to predict a statistically reliable future performance of such systems?

102. Is there not statistical variability in both the sampling of coal and its analysis, as well as in the sampling and analysis of mercury in the flue gas?

103. Is there not also statistical variability in the coal itself and therefore in the possible removal rates that will be achieved even given a steady state treatment technology?

104. Is there not also statistical variability in the efficacy of any of the treatment technologies?

105. What studies have been done to determine and account for the statistical variabilities in projecting enforceable removal rates or emission limits to your knowledge?

106. Is that not normally done in developing regulations and imposing mandatory requirements?

107. Are you familiar with the terms "commercially proven" and "commercially available?" Please state your understanding of each.

108. Please identify each mercury removal technology which is "commercially proven" and "commercially available" today to meet the requirements of the proposed Illinois rule.

Dated this 2nd day of June, 2006.

Respectfully submitted,

AMEREN ENERGY GENERATING COMPANY
AMERENENERGY RESOURCES GENERATING COMPANY
ELECTRIC ENERGY, INC.

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ADDITIONAL QUESTIONS FOR JAMES E. STAUDT, PH.D. REGARDING AMENDED TESTIMONY

1. At page 2 of your amended testimony you state that, "my testimony includes Section 8 of the Technical Support Document ("TSD"). Please explain in detail the changes to Section 8 of the TSD and the various tables including specifically Table 8.10 that would be required based on the amendments to your testimony and any new information that has come to your attention.

2. Please describe what additional information you received after submission of your original testimony that resulted in the two amendments to your testimony that have been submitted.

3. Please provide any documents that you were provided by the Illinois Environmental Protection Agency or anyone else, which resulted in the changes to your testimony in the two amendments.

4. Please state when this additional information was received by you.

5. Please describe in detail your role in drafting the amendment to the rule making proposal described as the Temporary Technology – Based Standard or TTBS.

6. On page 3 of your amended testimony you have stricken the following language:

> "Illinois bituminous coal is washed and some of the mercury is removed in the washing. However, Most of the coal burned in Illinois is subbituminous coal from the western US that is not washed because it is naturally low in sulfur and ash. For this reason and because of the higher energy content of bitunimonous coal, mercury content of bituminous coal as fired in Illinois power plants is typically below that of subbituminous coals on a heating value equivalent basis."

Please explain why you deleted this from your testimony, including what additional information you received that caused you to delete these statements.

7. You have inserted the language:

> "Mercury removal from the coal before combustion through washing will contribute to lower mercury emissions from the plant."

Please explain this additional statement.

8. You testify that washing all coal would contribute to lower mercury emissions. Does this apply to Powder River Basin coal?

9. On page 4 of your amended testimony, you have stricken the words "showed that" and inserted the words "provided data that indicates that the following cobenefit removal rates may be expected." Please explain the reason for this change in your testimony. **[Note: I propose deleting this and leaving his answer to this question in a way that allows us to draw the same conclusion without giving him a chance to weasel out of it.]**

10. In each of the bullet points on page 4 of your amended testimony, you have inserted the words "expected to be" or changed "likely" to "expected". Are these changes intended to indicate that in fact the data received by USEPA did not conclusively demonstrate these conclusions, but allows you to make some prediction of what might be achieved in the future?

11. In the first bullet point on page 4 you state that "co-benefit mercury capture is expected to be about 90%. Does this mean that co-benefit mercury capture is likely to be in the range of 90% but perhaps lower as well as perhaps higher?

12. Does this mean that consistent mercury removal of greater than 90% with SCR, ESP and FGD is not fully demonstrated?

13. In the second bullet point on page 4, you changed the phrase "will usually" to "is expected." Please explain this change.

14. On page 5 of your testimony with respect to sorbent injection you state: "Power companies have entered contracts for commercial systems, some with statutory requirements to achieve 90% or more mercury removal." Please identify each contract this statement contemplates, the state for which it is located and the corresponding statutory requirements to achieve 90% mercury removal, when it is required, and the predominant coal type used in those state(s). Please identify each state where "more" than 90% removal is required, when it is required, and the predominant type of coal used in those state(s).

15. What is the compliance date in each such state?

16. What types of coal do these power companies burn in the affected units?

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17. Do those contracts carry guarantees that the sorbent injection system will achieve 90% and if so, what is the consequence for failure to achieve 90%?

18. In the next sentence, you refer to the use of Powder Activated Carbon (PAC) for mercury control on municipal waste combustors. What is the difference in the chemical form of mercury in mass burn municipal waste combustors from power plants burning bituminous or subbituminous coals?

19. At page 6 under "Controlling Mercury from IL Units," you state,

> "coal-fired units in the state of Illinois are capable of meeting the requirements of the proposed mercury control rule at a cost close to that described in the TSD."

Are you referring to costs described in Table 8.8 of the TSD?

20. If not, to which costs are you referring?

21. When you refer to "at a cost close to that described in the TSD" please describe what you mean by "close to." Please provide the costs you estimated for this purpose, and the analysis you did to derive the costs.

22. Should the cost in the TSD, particularly Table 8.8 be amended based on the amendments to your testimony as referenced in this paragraph?

23. In that same paragraph you state:

> "There is a risk that a small number of coal-fired units in Illinois may need a Temporary Technology Based Standard (TTBS) until they bring their emissions reductions in compliance . . . ."

How many units are you referring to?

24. To which units at which plants are you referring?

25. What is the nature of the risk that these plants will not be able to achieve compliance with the standard?

26. What additional costs would you expect these plants to incur if they did not have temporary technology based standard?

27. Will these plants not ultimately have to incur these costs even if they do have a temporary technology based standard?

28. On page 7 of your amended testimony you reference two thirty-day continuous trials "where 93% or more mercury removal was achieved over the period." Which trials were those?

29. What was the size of the ESP on each of those units, the size of the boilers, and the coal type fired during the trials?

30. Was there any impact on operation of the ESP during either of those trials?

31. How does the size of the ESP's in those trials compare to the size of the ESP's in the Illinois facilities listed in Table 8.8?

32. In the next sentence in your amended testimony, you have increased the cost per hour from $160 to $180 per hour and the price of sorbent from 0.800 to 0.90 dollars per pound. Does this change in your testimony reflect the change in the cost of sorbent since your testimony was originally prepared? If not, why was your testimony changed in this regard?

33. In the next sentence you state that mercury removal will be better when sorbent is injected upstream of retrofit fabric filters. What specific data do you have to justify this assertion? What are the costs of such retrofits? Have those costs been accounted for in your calculations?

34. Are there any long-term tests to establish this?

35. Later in that paragraph you state,

> "There is a risk, however, that on some subbituminous-fired units the design of the existing particulate control device may limit the injection rate of sorbent due to PM control issues or the use of SO_3 flue gas conditioning may limit sorbent effectiveness – thereby limiting mercury emissions reduction."

At which units would you expect this to be an issue?

36. Are you aware of any data on these facilities demonstrating this to be true?

37. What are the design issues you reference in the above statement?

38. What is your understanding of the use of SO_3 flue gas conditioning prior to ESP's and the reason for it?

39. Of units using flue gas conditioning systems, how prevalent is the use of SO_3 as the conditioner in the industry, and in Illinois?

40. Are you aware of data indicating this impact of SO_3 flue gas conditioning?

41. What is the mechanism by which SO_3 flue gas conditioning limits the effectiveness of sorbent injection for removal of mercury?

42. What are the "halogenated sorbent injection rates" that would be required to overcome SO_3 flue gas conditioning impacts on sorbent effectiveness?

43. Based on your understanding of the mechanisms that might impact sorbent effectiveness with SO_3 flue gas conditioning, why would you expect that increasing the injection rate be expected to overcome those impacts?

44. Would those sorbent injection rates potentially interfere with particulate compliance?

45. Would they change your cost calculations, and by how much?

46. Could these injection rates interfere with the safe operation of the ESP or present dangers of fire in the duct work?

47. Are you aware of any situation where sorbent injection rates resulted in a fire in the duct work? If so, please describe what you know.

48. Later in that sentence you state "there are alternative flue gas conditioning methods that maybe used." Please state what those methods are.

49. Please indicate how many units use such systems within the industry and within Illinois. Please indicate whether those systems are as effective as SO_3 systems. Please indicate why alternative systems would not be expected to impact sorbent effectiveness.

50. Have such methods ever been used in conjunction with testing halogenated activated carbon injection?

51. Are you aware of tests that demonstrate that such flue gas conditioning is equally effective in assisting and maintaining particulate and opacity compliance?

52. What would be the cost impact of using alternative flue gas conditioning methods?

53. What time requirements might be necessary to design, procure and install alternative flue gas conditioning systems?

54. In the next sentence you state, "therefore I would expect few, if any units would use a TTBS until they could comply with the reduction requirements of the rule." What is the basis for this statement?

55. Which units would be most likely to require a TTBS and what characteristics would they have?

56. Which units presently using flue gas conditioning do you believe would achieve compliance with the rule within the deadline currently set forth in the rule without the TTBS?

57. In the next paragraph you state that bituminous coal units with SCR and FGD will either achieve the regulatory rate or can do so through scrubber optimization. Please state what you mean by "scrubber optimization."

58. Please state what "scrubber chemical additives" you refer to in this paragraph.

59. Please state whether these costs were included in Table 8.8 of the Technical Support Document, and if not, why not.

60. If these costs were not stated in the TSD, particularly Table 8.8, please state what these costs would be.

61. You have struck the language,

> "Full scale tests have shown that halogenated sorbents can achieve high removal rates on low to medium sulfur bituminous coal, albeit at somewhat higher injection concentrations than for PRB fuels."

Did you strike this statement because it was not true?

62. The original testimony also stated:

> "Combined with some cobenefit removal, over 90% mercury removal with halogenated sorbent injection in the range of 6-7 lb/MMacf has been shown at several units."

Which units are these, what coals were fired and under what conditions was this demonstrated?

63. On page 8 of your amended testimony you state:

> "Full scale tests have shown that halogenated sorbents can achieve high removal rates on medium sulfur coal, albeit at slightly higher injection concentrations than for PRB fuels."

Which tests do you refer to here and what rate of removal did they achieve?

64. You reference 90% mercury removal with halogenated sorbent injection. Over what period of time was this removal rate achieved and how was the 90% removal calculated?

65. What was the minimal removal achieved during the tests and what was the maximum removal achieved during the tests?

66. You state that "for the unscrubbed high-sulfur coal capacity, less mercury removal is likely," referring apparently to Meredosia's smaller units. What mercury removal do you expect them to achieve on a consistent annual basis?

67. How do you expect them to achieve this rate?

68. You then state, "I expect that the much larger Meredosia #5 is capable of over 90% removal with halogenated activated carbon." Please state in detail how you arrived at this conclusion.

69. Please state what your knowledge of the layout of the Meredosia #5 boiler is.

70. Do you know what coal is being fired in the Meredosia #5 boiler?

71. Do you know the size of the Meredosia #5 unit?

72. Do you know the size of the ESP on the Meredosia #5 unit?

73. Do you know whether it requires SO_3 injection or other flue gas conditioning to achieve compliance with the applicable opacity and particulate standards?

74. If it does achieve over 90% removal, what level of removal do you expect it to achieve?

75. What level of removal would the Meredosia #5 unit need to achieve in order to average over 90% control with Meredosia boilers #1 through 4?

76. What degree of confidence do you have in this prediction?

77. Would you or your company take a contract to install and operate the boilers you describe at Meredosia with severe penalties including paying any compliance or other costs incurred by the owner of these boilers if they failed to achieve the 90% reduction you project?

78. Would your company do so for any unit with an SO_3 flue gas conditioning system?

79. What level of removal would your company be willing to guarantee on a unit with an SO_3 flue gas conditioning system?

80. Would the SO_3 system impact the level of guarantee you might offer?

81. If the Meredosia boilers #1 – 4 shifted to low-sulfer coal as you suggest is possible, would you project that they would achieve over 90% reduction with halogenated activated carbon injection at these specific facilities?

82. Will you expect these facilities to require SO_3 injection to achieve compliance with the opacity and particulate limitations?

83. What are the size of the ESPs on each of these units?

84. Where would you inject halogenated activated carbon on each of these units?

85. On page 9 you state:

> "In the event that some units comply through a TTBS until they can achieve the required mercury emission reductions, the cost difference will be only slightly higher. There is, however, a small risk that some units will be unable to comply with the rule as anticipated in the TSD due to the limitation on the allowable MW that may use a TTBS. In this case, these units will require more costly controls."

86. Which units would be required to install additional controls ultimately to come in compliance with the rule?

87. What additional controls or measures would you expect those utilizing the TTBS to incur in order to ultimately come into compliance?

88. Which units do you believe will not be able to comply with the rule as anticipated in the TSD due to the limitation on the allowable MW that may use a TTBS?

89. What additional controls would these units require?

90. Would they require a TOXECON system?

91. Would not such additional controls be considerably more expensive than estimated in the technical support document and if so, how much more?

92. How do you arrive at the conclusion that "the limitation on the amount of generating capacity that may use a TTBS is likely to be sufficient to address the small number of units that may require extra time to comply."

93. What are the units expected to do with the extra time?

94. If they cannot comply now, will they be able to comply when the TTBS sunsets, and why?

95. How did you include the costs for units covered by the TTBS when the TTBS sunsets in your calculations?

96. How is the 25% limitation in the new proposed TTBS limit calculated?

97. Did you personally arrive at that figure, or was that figure derived from someone else?

98. What is the rationale for selecting 25%?

99. What is the rationale for limiting the use of TTBS to only 25% of the megawatts?

100. If you expect that few, if any units, would need to make use of the TTBS, why was 25% selected?

101. If a unit installs halogenated activated carbon injection as you recommend and optimizes performance without interfering with particular controls or compliance with opacity and particulate limits, why should it not qualify for a TTBS?

102. If you are confident that such units can comply, what harm would there be in allowing them to qualify for a TTBS should the controls you are relying upon prove unable to achieve the desired limit?

103. If you are confident that most, and perhaps all, units can comply within the timeframe and costs that you have estimated, why is it proper to place the risk that your assessment is correct on the generators?

104. Is it fair to say that the costs of the proposal depend largely and perhaps exclusively on whether your performance assessment is correct?

105. Is it fair to say that the costs of the proposal are incorrect unless your assessment is correct?

106. In an October 2005 presentation you predicted that fragmented or mixed allowance markets would emerge if states adopted mercury rules different than CAMR, and that in such a market, demand would increase for mercury-specific control technologies such as sorbent injection systems. Does your company sell such systems?

107. Would this proposal contribute to the fragmented or mixed allowance market you describe?

108. With respect to the proposed TTBS, what role did you have in drafting it?

109. With respect to subpart B, "Eligibility of the TTBS," why were brand name sorbents listed?

110. Are they all equally effective and interchangeable?

111. Did you select the injection rate for subbituminous coal at 5 lbs/per million actual cubic feet?

112. If not, do you know who did?

113. On what did you base that selection if you did?

114. On what did you select the injection rate of 10 lbs/per million actual cubic feet for bituminous coal?

115. [On what basis did you select that rate? SAME?]

116. With respect to either rate, do you expect any adverse impact over the long term on the operation, maintenance and performance of the ESPs?

117. At what facilities similar to those in Illinois were these injection rates used over any extended period of time?

118. Should not the injection rate under the TTBE also be limited to prevent interference with safe operation of the ESP?

119. Should not the injection rate also be limited to prevent interference with the safe operation of the ESP?

120. What is the basis for limiting the TTBS to 25% of the total rated capacity of any single owner or operator?

121. How was this number derived?

122. Have you calculated the increase in emissions that would trigger new source review and the possibility that sorbent injection could trigger it?

Dated this 2nd day of June, 2006.

Respectfully submitted,

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