BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
NITROGEN OXIDES EMISSIONS FROM	)	R08-19
VARIOUS SOURCE CATEGORIES:	)	(Rulemaking – Air)
AMENDMENTS TO 35 ILL. ADM. CODE	)	
PARTS 211 AND 217	)	

NOTICE

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

SEE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that I have today filed with the Office of the Clerk of the Illinois Pollution Control Board the ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S ANSWERS TO MIDWEST GENERATION'S QUESTIONS FOR AGENCY WITNESSES, a copy of which is herewith served upon you.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: ______________________
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DATED: September 30, 2008

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THIS FILING IS SUBMITTED ON RECYCLED PAPER

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THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S ANSWERS TO MIDWEST GENERATION'S QUESTIONS FOR AGENCY WITNESSES

NOW COMES the Illinois Environmental Protection Agency ("Illinois EPA"), by its attorneys, and pursuant to the Hearing Officer's Order dated June 12, 2008, respectfully submits the Illinois EPA's Answers to Midwest Generation's Questions for Agency Witnesses:

Questions for Mr. Kaleel

1. Please explain the relationship between these proposed rules establishing reasonably available control technology ("RACT")/reasonably available control measures ("RACM") for the current ozone and fine particulate matter ("PM2.5") national ambient air quality standards ("NAAQS") and what may be required for the revised ozone and PM2.5 NAAQS.

   Unless USEPA issues new guidance regarding NOx control technology, we expect that this RACT proposal will satisfy requirements to implement NOx RACT under the revised NAAQS for the source categories and geographic areas to which this proposal applies. The Illinois EPA has not yet determined the emissions reduction measures needed to attain the revised ozone and PM 2.5 NAAQS. It may be necessary to implement more stringent measures, however, if additional measures are necessary for attainment.

2. What distinction, in the definitions or use, between industrial boilers, fossil fuel-fired boilers, and electric generating units ("EGUs") does the Agency make or intend in this rule?

   EGU boilers are used primarily to generate electricity to sell on the electricity grid. Industrial boilers are used primarily to generate power (steam or electricity) for use at the source. Both types of boilers may use fossil fuels, coal, oil, or gas.

3. If there are no cement kilns in the nonattainment areas, why are cement kilns included in this rulemaking? Likewise, if there are no aluminum melting furnaces affected, why does the rule include that sector?

   There is an aluminum melting furnace in the Chicago non-attainment area (NAA), although it has not operated for several years. To the best of our knowledge, the emission unit has not been torn down, so it is possible that the company, or a future

owner, will seek to operate the furnace in the future. There are no cement kilns in the current NAAs, although there is a cement kiln in Massac County, which USEPA intends to designate as nonattainment for the 24-hour PM2.5 NAAQS. The attached letter shows USEPA's intent regarding Massac County. See, Attachment 1.

4. How will the limitation of a unit to only one emissions averaging plan in this rule interact with the averaging plan provisions of other rules? That is, is it the Agency's intent for this rule to preclude participation or inclusion of a unit that is in an averaging plan under this rule from participating in averaging plans under other rules and vice versa?

It is the Illinois EPA's intent that an emission unit be included in only one seasonal and one annual averaging plan. Units affected by Subpart Q (Engine Rule) can be included in an averaging plan with units affected by this proposal.

5. In Section 217.150(a)(2), the regulatory language uses the word "emits." How will the Agency determine whether a unit is subject to the rule? That is, how will the Agency determine whether a unit emits, as opposed to having the potential to emit, at the threshold levels?

In general, the Illinois EPA intends to rely on Annual Emission Reports submitted by owners/operators of emissions sources.

6. Applicability of Subpart M and the nonapplicability of Subpart D are premised upon the applicability of the Part 225, Subparts C, D, and E ("the Illinois [Clean Air Interstate Rule] CAIR") to electric generating units ("EGUs"). However, the federal rule underlying the Illinois CAIR has been overturned (assuming that the D.C. Circuit Court issues the mandate for its decision in appeal of the rule), thus invalidating the Illinois CAIR. Therefore, it appears that EGUs, which the Agency apparently intended to cover in Subpart M of this rulemaking, are covered by Subpart D. Does the Agency intend to amend the language in Subpart M? If so, how?

The Illinois EPA does not agree with the underlying premise of this question; however, the Illinois EPA is amenable to amending Sections 217.340, 217.342, 211.3100, and 217.160 as set forth in the response to Question 20, below.

7. What does the Agency consider to be the nominal cost per ton for RACT for nitrogen oxides ("NOx")?

The USEPA and the Illinois EPA have not established a specific cost threshold for RACT, although the Illinois EPA has used $2500 to $3000 per ton as a range for cost effectiveness.

8. Does a load shaving unit (Section 211.3475) include a peaker power plant?

Yes.

9. Section 217.150(a) says, "The provisions of this Subpart and Subparts D, E, F, G, H, and M" of this Part apply to ... 1) All sources...." (Emphasis added.) Is it the Agency's intent

that all of these subparts actually apply to all sources in the specified geographic areas? Isn't actually the Agency's intent that only one subpart will apply to a unit or units at threshold sources, as determined by the characteristics of the unit?

It is the Illinois EPA's intent that each respective Subpart apply to sources that meet the applicability criteria and individual emission units at such sources that meet the applicability criteria, i.e., the provisions of a respective Subpart apply to the extent a source includes emission units of the type covered under that Subpart.

10. The "all industrial boilers" language in Section 217.160(a) and similar language in the other subparts could be construed to expand the scope of Section 217.150(a)(2), which refers to "any industrial boiler [and other types of emission units] that emits NOx in an amount equal to or greater than 15 tons per year and equal to or greater than five tons per ozone season." Is it the Agency's intent to expand the applicability of the rule in this way?

The Illinois EPA's intent is that each Subpart apply to all of the affected emission units at an affected source, e.g., "any" emission unit that meets the applicability criteria.

11. Is it the Agency's intent that the proposed rule applies to areas designated nonattainment for either ozone or PM2.5?

Yes.

12. What comprises the second compliance period if the first is May 1, 2010, through April 30, 2011, and then is subsequently on a calendar year basis? *See* Section 217.152.

January 1, 2011, through December 31, 2011.

13. How is the second sentence of Section 217.152(b) ("The owner or operator of an emission unit that is subject to Subpart D, E, F, G, H, or M must operate such unit in a manner consistent with good air pollution control practice to minimize NOx emissions." related to the compliance date?

There is no relation.

14. Can the recordkeeping systems that sources already have in place comprise the "logs" required at Sections 217.156(b)(8) and (9), assuming all of the information required by the rule is included?

Yes, as long as all of the required information under the rule is included.

15. What is an "applicable compliance period" referred to in Section 217.156(g)?

The annual or ozone season compliance period.

16. Does Section 217.156(k), which requires compliance certifications, recordkeeping, and reporting for Subpart M units pursuant to 40 CFR Part 96, supersede the other recordkeeping and reporting requirements of Section 217.156?

The Illinois EPA's intent is that electric generating units subject to Subpart M comply with the compliance certifications, recordkeeping, and reporting requirements pursuant to 40 CFR Part 96, in conjunction with the other recordkeeping and reporting requirements under Section 217.156, to the extent the requirements are not duplicative.

17. Does the Agency have information confirming that the stacks at affected units that are typically small can be tested safely, as required by Section 217.157?

No.

18. Section 21 7.158(b) requires that averaging plans be submitted by May 1, 2010. What if a source decides in 2010 that it does not want to average, but in 2015 it decides that it does want to average? Is that source precluded from establishing an averaging plan? Is this a "once out/always out" provision?

Averaging plans can be amended once per year at the discretion of the owner/operator. Units not previously included in an averaging plan can be included at a date later than May 1, 2010. It is not the Illinois EPA's intent to establish a "once out/always out" provision.

19. What is the Agency's basis for establishing a rate of 0.08 lb/mmBtu rate for gas-fired industrial boilers greater than 100 mmBtu? (Section 217.164(a))

The basis for this limit is set forth in the TSD, at page 43, specifically, Table 2-17a: Cost Effectiveness Data for Natural Gas-Fired ICI Boilers.

20. Based upon the proposed applicability language in Subpart M, Section 217.340, assuming the D.C. Circuit Court issues the mandate implementing its decision in the appeal of the CAIR, EGUs would be subject to the provisions of Subpart D. Is the Agency amenable to amending Sections 217.340, 217.342, 211.3100, and 217.160, as follows:

Section 217.340 Applicability [Subpart M]

Notwithstanding Subpart V or W of this Part, the provisions of Subpart C of this Part and this Subpart apply to ~~all fossil fuel-fired stationary boilers subject to the CAIR NOx Trading Programs under Subpart D or E of Part 225~~ <u>any fossil fuel-fired stationary boiler serving a generator that has a nameplate capacity greater than 25 MWe and produces electricity for sale, excluding any units listed in Appendix D of this Part,</u> located at sources subject to this Subpart pursuant to Section 217.150 of this Part.

Section 217.342 Exemptions

a) Notwithstanding Section 217.340 of this Subpart, the provisions of this Subpart do not apply to a fossil fuel-fired stationary boiler operating under a federally enforceable limit of NOx emissions from such boiler to less than 15 tons per year and less than five tons per ozone season.

b) Notwithstanding Section 217.340 of this Subpart, the provisions of this Subpart do not apply to a coal-fired stationary boiler that commenced operation before January 1, 2008, that is complying with <u>Part 225.Subpart B through</u> the multi-pollutant standard under Section 225.233 of Part 225 or the combined pollutant standards under Subpart F of Part 225.

Section 211.3100 Industrial Boiler

"Industrial boiler" means, for purposes of Part 217, an enclosed vessel in which water is heated and circulated either as hot water or as steam for heating or for power, or both. This term does not include boilers serving a generator that has a nameplate capacity greater than 25 MWe and produces electricity for sale, and cogeneration units, as that term is defined in Section 225.130 of Part 225~~, if such boilers or cogeneration units are subject to the CAIR NOx Trading Programs under Subpart D or E of Part 225~~.

Section 217.160 Applicability [Subpart D]

b) The provisions of this Subpart do not apply to boilers serving a generator that has a nameplate capacity greater than 25 MWe and produces electricity for sale, and cogeneration units, as that term is defined in Section 225.230 of Part 225~~, if such boilers or cogeneration units are subject to the CAIR NOx Trading Programs under Subpart D or E of Part 225~~.

The Illinois EPA is amenable to amending Sections 217.340, 217.342, 211.3100, and 217.160 as follows:

Section 217.340 Applicability [Subpart M]

Notwithstanding Subpart V or W of this Part, the provisions of Subpart C of this Part and this Subpart apply to ~~all fossil fuel-fired stationary boilers subject to the CAIR NOx Trading Programs under Subpart D or E of Part 225~~ <u>any fossil fuel-fired stationary boiler serving at any time a generator that has a nameplate capacity greater than 25 MWe and produces electricity for sale, excluding any units listed in Appendix D of this Part,</u> located at sources subject to this Subpart pursuant to Section 217.150 of this Part.

Section 217.342 Exemptions

a) Notwithstanding Section 217.340 of this Subpart, the provisions of this Subpart do not apply to a fossil fuel-fired stationary boiler operating under a federally enforceable limit of NOx emissions from

such boiler to less than 15 tons per year and less than five tons per ozone season.

b) Notwithstanding Section 217.340 of this Subpart, the provisions of this Subpart do not apply to a coal-fired stationary boiler that commenced operation before January 1, 2008, that is complying with Part 225.Subpart B through the multi-pollutant standard under Section 225.233 of Part 225 or the combined pollutant standards under Subpart F of Part 225.

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"Industrial boiler" means, for purposes of Part 217, an enclosed vessel in which water is heated and circulated either as hot water or as steam for heating or for power, or both. This term does not include boilers serving a generator that has a nameplate capacity greater than 25 MWe and produces electricity for sale, ~~and cogeneration units, as that term is defined in Section 225.130 of Part 225,~~ if such boilers ~~or cogeneration units are subject to~~ meet the applicability criteria under Subpart M of Part 217 ~~the CAIR NOx Trading Programs under Subpart D or E of Part 225~~.

Section 217.160 Applicability [Subpart D]

b) The provisions of this Subpart do not apply to boilers serving a generator that has a nameplate capacity greater than 25 MWe and produces electricity for sale, ~~and cogeneration units, as that term is defined in Section 225.230 of Part 225,~~ if such boilers ~~or cogeneration units are subject to~~ meet the applicability criteria under Subpart M of Part 217 ~~the CAIR NOx Trading Programs under Subpart D or E of Part 225~~.

21. What is the basis for determining that the 0.09lb/mmBtu rate at Section 217.344(a) is RACT?

The technologies to control utility boilers to below 0.09 lb/MMBtu are certainly available as evidenced by the number of utility boilers in Illinois and throughout the United States that currently control to that level or less. Emissions data for over 100 coal units equipped with SCRs and other low NOx technology were examined in a comprehensive study by Erickson and Staudt with the results presented at the EPA-DOE-EPRI Combined Power Plant Air Pollution Control Symposium (the MEGA Symposium) in 2006. See, Attachment 29 to the TSD, Selective Catalytic Reduction System Performance and Reliability Review, the 2006 MEGA Symposium, Paper #121, by Clayton A. Erickson and James E. Staudt. Without a doubt, coal-fired units have demonstrated that emissions under 0.09 lb/MMBtu are possible using combustion controls, post-combustion controls, or combinations of the two. In fact, Illinois' own Baldwin Unit #3 achieves below 0.09 lb/MMBtu using only combustion control. Other units in Illinois achieve under 0.09 lb/MMBtu using SCR.

So, from the perspective of RACT, the only remaining question is whether or not the technology is reasonable in cost. As a benchmark of what is reasonable, the United States Environmental Protection Agency (USEPA) determined in its Clean Air Interstate Rule analysis, which motivated installation of SCRs, that

> The EPA's analysis indicates that emissions reductions from electric generating units (EGUs) are highly cost effective, and EPA encourages States to adopt controls for EGUs.

See, 70 Fed. Reg. 25162, 25165 (May 12, 2005).

Further, in describing what is "highly cost effective" USEPA stated:

> (II) Determination of Highly Cost-Effective Amount
>
> The EPA determined the dollar amount considered to be highly cost effective by reference to the cost effectiveness of recently promulgated or proposed NOX controls. The EPA determined that the average cost effectiveness of controls in the reference list ranged up to approximately $1,800 per ton of NOX removed (1990$), on an annual basis. The EPA considered the controls in the reference list to be cost effective.

See, 70 Fed. Reg. 25162, 25173 (May 12, 2005).

It is widely recognized that combustion controls are reasonable in cost. However, SCR also provides NOx reductions at reasonable costs. Figure 2-17 from the TSD can be used to make this point. A capital cost of $200/KW is near the high end of what a utility SCR retrofit would typically be expected to cost and this translates roughly to $20,000/MMBtu/hr, assuming a heat rate on the order of 10,000 Btu/kWhr. Using Figure 2-17 and an assumed uncontrolled NOx level of 0.50 lb/MMBtu, one arrives at $2000/ton of NOx removed. Uncontrolled units would typically have an emissions rate of at least 0.50 lb/MMBtu. But, even at uncontrolled NOx levels of 0.40 lb/MMBtu, the cost is estimated at about $2500/ton. For more typical capital cost numbers in the range of $100/KW to $150/KW (roughly $10,000-$15,00 0/MMBtu/hr on Figure 2-17), the cost of NOx reduction would be below $2000/ton. Companies typically do not publish their cost data. But, fortunately, cost data is available for some SCR retrofits. As shown in the attached report submitted by Progress Energy to the North Carolina Public Utilities Commission, the Asheville Unit 1 SCR retrofit cost $28 million on the 191 MW unit - $149/KW. See, Attachment 2. And, as reported in Power Engineering Magazine, (http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/), in an article titled "SCR = Supremely Complex Retrofit), Duke Power's two Belews Creek Units (2 times 1120 MW) were retrofit for $325 million, or $145/KW. See, Attachment 3. Thus, a "Supremely Complex Retrofit" cost $145/KW.

According to a study of SCR costs published by Murano and Sharp in February 2006, (http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717)

> **"Overall, costs were reported to be in the \$100 to \$200/kW range for the majority of the systems (Figure 2), with only three reported installations exceeding \$200/kW. System size (with a 644-MW average unit size in the \$100 to \$150/kW range) seems to dominate; larger average system costs are significantly less than the next survey category (the \$150 to \$200/kW range, with a 309-MW average unit size)."**

See, Attachment 4. As a result, multiple studies have affirmed the cost of SCR to be in a capital cost range where they are shown to provide reductions below the "highly cost effective" level established by USEPA.

Earlier studies using capital costs in the range of \$70-\$90/KW determined that NOx could be controlled from SCR at costs in the range of \$400-\$1768/ ton. See, Attachment 22 to the TSD, and Attachment 5, Cichanowicz, "SCR for Coal-Fired Boilers: A Survey of Recent Utility Cost Estimates," EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium, the MEGA Symposium, August 25-29, 1997, Washington, DC. This is below the \$1800/ton (in 1990\$) that USEPA determined to be "highly cost effective." However, SCR costs have gone up faster than inflation. But, even doubling that cost range to \$800-\$3536/ton of NOx reduced to account for escalation of SCR costs, keeps the cost in the range of what USEPA determined to be "highly cost effective" except at the very highest end.

22. The Technical Support Document ("TSD") indicates on page 130 that there are a total of 12 industrial boilers subject to the NOx SIP call affected by this proposed rule while the Statement of Reasons on page 10 states that there are 80 industrial boilers affected by the proposed rule. Are these additional 50 industrial boilers all less than 250 mmBtu?

    The additional 68 industrial boilers are less than 250 mmBtu and are not subject to the NOx SIP Call.

23. The TSD claims there are a total of 18 EGUs subject to the rule, while the Statement of Reasons says there are 20 "fossil fuel-fired stationary boilers" subject to the rule. Are there fossil fuel-fired stationary boilers that are not EGUs that are subject to the rule?

    No, there are 20 EGU boilers. Table E-1 of the TSD Appendices lists units; however, there are two instances in which one unit is comprised of two boilers (see, Midwest Generation LLC, Joilet 29: Unit 7, Boilers 71 and 72, and Joliet 29: Unit 8, Boilers 81 and 82).

<u>Questions for Dr. Staudt</u>

24. Are NO and NO_2 the <u>only</u> components of NOx?

    Yes, however, they are reported on a mass basis as if they were all in the form of NO_2. For boilers, the majority of the NOx is in the form of NO as it leaves the stack. However, the NO subsequently oxidizes to NO_2 in the atmosphere.

25. Explain oxy-combustion. In your testimony, you say that NOx is reduced by reducing the amount of oxygen available for the nitrogen to combine with, yet oxy-combustion appears to provide even more oxygen in the combustion chamber.

Oxycombustion is described in my testimony as a nitrogen-depletion approach. Normally, nitrogen comprises 79% of combustion air. By having an enriched oxygen environment, nitrogen is depleted in the combustion air to much lower amounts. One benefit of this is that there is less nitrogen available to oxidize at high temperature to NO or NO_2.

26. Your testimony suggests there are other post-combustion controls besides SCR and SNCR. What are those other types of post-combustion controls?

Other approaches include oxidation of the NO to water soluble oxides using ozone, peroxide, or with an electric barrier discharge reactor, and then scrubbing them out with a wet scrubber, and injection of Trona. Duct injection of Trona (sodium sesquicarbonate) will remove some NOx as well as SO_2. However, SNCR and SCR are the most widely used post-combustion controls.

27. Is SCR RACT? Or is it beyond RACT?

SCR can be RACT. In fact, the first retrofit of SCR on a coal fired utility boiler was at Public Service Company of New Hampshire's Merrimack Unit #2 in 1995, and this was in response to New Hampshire's NOx RACT rule that was implemented at that time. SCR has been retrofit on several other coal fired boilers in response to the Ozone Transport Commission NOx budget rule (PSNH Merrimack 1) and on a number of Group 2 boilers in response to regulations enacted under Title IV of the Clean Air Act. Both of these regulations were ostensibly intended to impose NOx controls at a cost ($/ton of NOx) similar to low NOx burners, which are widely regarded as within RACT. If $2500-$3000/ton is to be the guide for what is RACT, Figure 2-17 of the TSD demonstrates that SCR is capable of being RACT. However, having said that, I do not believe that SCR is likely to be necessary under the proposed rule. I expect that less expensive controls or combinations of less expensive controls are most likely to be used.

28. Would a wet scrubber intended to reduce SO_2 be a NOx scrubber as well if the NOx were first oxidized? *See* Section 1.2.2, page 4 of the TSD.

Yes, if the NOx were both oxidized to a water-soluble form and subsequently captured in the scrubber.

29. What does the following mean: "NOx emissions from residual oil-fire boilers can be controlled level by using residual fuel oil. ..." (Emphasis added.) *See* Section 2.1, page 5 of the TSD.

The term "level" is a typographical error. Once you remove that, the sentence should make sense. But, to explain, reducing fuel nitrogen is a way of controlling NOx emissions.

30. Is it the case that there are currently no wood-fired boilers that would be subject to the proposed rule?

That is my understanding.

31. Does the fact that pulverized coal is used in wall-fired boilers contribute to the NOx levels? *See* Section 2.2.1, page 9 *ff.* of the TSD.

Yes, coal contains significant levels of fuel nitrogen, which contributes to NOx.

32. Page 13 of the TSD says that Cleaver Brooks illustrates that with proper control, NOx emissions can be reduced, and page 15 of the TSD says that Cleaver Brooks illustrates that with proper retrofits, NOx emissions can be reduced. What are those "proper" controls and retrofits? How are they effective in reducing NOx? Who is Cleaver Brooks?

The "proper" retrofits referred to are low NOx burners. The effectiveness of these controls in reducing NOx is shown in Tables 2-2 and 2-3 of the TSD, which are from Cleaver Brooks and referenced in a letter, dated May 19, 2006, submitted by Daniel J. Willems of Cleaver Brooks to the New Hampshire Division of Environmental Services (see, Attachment 8 to the TSD). The data in these tables demonstrate that these burners are capable of achieving emission rates at extremely low levels – well below the proposed limits. As noted in the TSD, at page 13, Cleaver Brooks is the largest producer of hot water and steam boilers in the United States.

33. How do excess air and complete combustion affect safety? *See* Section 2.3.1, page 20 of the TSD.

Reducing excess air too far can make the flame unstable or even extinguish it. In this case there is a risk of high combustible levels remaining in the gas that can affect safety. In a worst-case scenario there is risk of a boiler explosion. However, operating limitations and control devices prevent these conditions from occurring. As excess air is reduced, operating limitations on CO emissions or high unburned carbon in the case of coal-fired boilers will be reached well before unsafe conditions are reached, preventing the operator from reducing excess air further. Also, boilers have flame monitors as part of their controls that also assure safety by alerting the operator to a problem with the flame. So, a boiler is capable of operating at low excess air to reduce NOx while also operating in a safe manner.

34. Page 22 of the TSD refers to 100-600 hp boilers. How large are these boilers in terms of mmBtu heat input capacity?

One hp is 2524 Btu/hr. So, 100-600 hp boilers are in the range of 252,000 Btu/hr to about 1.5 million Btu/hr. The specific reference you have identified is in the section on combustion tuning (mostly of interest for small boilers) and relates to the cost of oxygen trim systems in the range of $6000-$7000 for boilers of that size. And, as noted in the TSD, for larger boilers the cost would be somewhat higher. Of course,

100-600 hp boilers are well below the size of boilers that are subject to emissions limitations. However, small boilers may be subject to the combustion tuning requirement, depending upon the emissions of the boiler.

35. Please describe the combustion tuning training requirement and where companies may obtain such training.

This is described in the TSD. Boiler manufacturers and private companies offer such training. The American Boiler Manufacturer's Association website (www.abma.com/training.html) lists training courses that are available.

36. Regarding SNCR, the TSD says that there need to be several injection points to inject the reagent at proper temperatures for large boilers. What happens if the reagent is injected at an improper temperature? *See* page 30 of the TSD.

The injectors are placed in locations on the boiler designed to inject the reagent into a temperature zone where the desired chemical reactions occur. The proper temperature zone changes as boiler conditions, such as load, change. So, multiple injection zones may be needed. SNCR systems have control systems to determine the proper injectors to use for a given load such that the reagent is injected in the correct location (and therefore, the correct temperature) at all times. Since there are hundreds of SNCR systems installed on industrial and utility boilers, this is something that engineers have good experience with. If the reagent were not injected in the proper location (where the correct temperature is), then poor NOx reduction or high ammonia slip would result.

37. Why would the cost of SNCR on a wood-fired boiler be about the same as for a coal-fired boiler of the same size?

The capital cost of an SNCR system depends primarily on the number of injectors, which is largely related to the boiler size and heat input, and the amount of reagent used (which determines the size of the storage tank). So, for solid fuel boilers of similar heat input and similar NOx levels, you would expect similar costs.

38. Looking at Table 2-12a, what is a "Wood Fired IPP"? In this same column, the table says that the fuels are "Biomass Wood/Coal." What does this mean?

A "Wood fired IPP" is an Independent Power Producer that has a boiler that burns wood. Fuels "Biomass Wood /Coal" mean that the boiler fires those fuels – and may fire combinations of these fuels.

39. Page 30 of the TSD states, "For EGU's SNCR capital cost is in the range of about $15/KW, and in most cases NOx reductions in the rage of about 30% are possible." How does this translate to dollars per ton of NOx removed?

Figures 2-14a and 2-14b of the TSD, which are data for Industrial/Commercial/Institutional (ICI) boilers, are also useful for getting a sense of the cost for utility boilers if you look at the far right where the information for

large ICI boilers is shown. As shown in Figure 2-14b, the capital cost is about $1500/MMBtu for large ICI boilers, which is roughly equivalent to $15/KW. And, as shown in Figure 2-14a, the $/ton of NOx reduced is in the range of about $1500/ton on an annual basis.

40. On page 36 of the TSD is a discussion of the cost of SCR; the TSD appears to essentially argue that a cost expressed in dollars per mmBtu is a better measure of RACT because an expression in dollars per ton removed depends upon baseline NOx. Please explain.

    This does not argue for or even suggest a different measure for RACT. The reason the cost in $/MMBtu is shown is to give the cost in terms of fuel use, which may be useful for industrial boiler owners in the same sense that $/MWhr would be of interest to a power plant owner.

41. Have the cost calculations for industrial/commercial/institutional ("ICI") boilers included retrofit issues?

    Yes

42. It appears that the TSD includes a number of evaluations of cost-effectiveness of proposed rule from a number of different sources. What is the bottom line, *i.e.,* the Agency's determination of the cost-effectiveness of the proposed rule, in at least 2006 dollars? *See* TSD pages 41-42.

    The bottom line is as stated in my prefiled testimony.

    "Fortunately, for each of the source categories affected there are available controls that can be used to provide the NOx reductions required by the rule at costs envisioned to be within the expectations for RACT."

43. What is the significance of the statement on page 126 of the TSD that "the [USEPA cost] model does not allow for differences in stack height, or explicitly distinguish between Part 60 and Part 75 systems"?

    The significance of this statement is that the model used was developed primarily for utility boilers, which generally have taller stacks than industrial boilers and Part 75 systems. Therefore, I would expect that an industrial boiler continuous emissions monitoring system's (CEMS) costs would likely be less since the stacks are smaller and also they would likely have a Part 60 CEMS.

44. The TSD at page 126 suggests that opacity monitoring is required by this rule where a source, because of the size of the affected unit, must employ Part 75 monitoring. Is it the intent of this rule to require opacity monitoring? If so, why is opacity monitoring part of a NOx RACT rule?

    No.

45. What is a "point source"? *See* TSD page 130. Is the term defined in the rule?

A point source is an individual stationary emission unit. No, the term is used in the TSD, but is not defined in the rule.

46. The TSD states on page 131, "The NOx inventory was generated through the use of year 2005 annual emission reports submitted pursuant to 35 Ill. Adm. Code Part 234. For our purpose, year 2005, instead of year 2002, was selected because some sources have been either shut down or modified since 2002." What is the significance of 2002 that the TSD would explain using 2005 data instead?

USEPA's implementation rules for ozone and PM2.5 require the use of 2002 as the base year for emissions inventories and determining reasonable further progress. The Illinois EPA used 2005 emissions data to identify potentially affected units because 2005 data are more current.

47. Please explain the difference between Tables H-l and I-I. Appendix pages 31 and 33.

Table H-1 sorts all sources by the ID number, whereas Table I-1 groups them by emission category and nonattainment area.

48. In Appendix A, Table A-4, what does "703" in the first column mean?

It means uncontrolled emissions are 703 tons per year for the gas fired refinery boiler that was being evaluated in Table A-4.

Respectfully submitted,

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

By: ______________________

Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

DATED: September 30, 2008

1021 North Grand Avenue East
P. O. Box 19276
Springfield, IL 62794-9276
217/782-5544

THIS FILING IS SUBMITTED ON RECYCLED PAPER

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

CERTIFICATE OF SERVICE

I, the undersigned, an attorney, state that I have served electronically the attached ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S ANSWERS TO MIDWEST GENERATION'S QUESTIONS FOR AGENCY WITNESSES, upon the following person:

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

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

SEE ATTACHED SERVICE LIST

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY,

Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

Dated: September 30, 2008

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AUG 18 2008

REPLY TO THE ATTENTION OF:

R-19J

The Honorable Rod Blagojevich
Governor of Illinois
Springfield, Illinois 62706

Dear Governor Blagojevich:

Thank you for your recommendations on the status of fine particle ($PM_{2.5}$) pollution throughout Illinois. As you know, fine particle pollution represents one of the most significant barriers to clean air facing our nation today. Health studies link these tiny particles – about 1/30th the diameter of a human hair – to serious human health problems including aggravated asthma, increased respiratory symptoms like coughing and difficult or painful breathing, chronic bronchitis, decreased lung function, and even premature death in people with heart and lung disease. Fine particle pollution can remain suspended in the air for long periods of time and create public health problems far away from emission sources. Reducing levels of fine particle pollution is an important part of our nation's commitment to clean, healthy air.

We have reviewed the December 18, 2007, and June 2, 2008, letters from Laurel L. Kroack, Chief of the Bureau of Air, Illinois Environmental Protection Agency, and the August 6, 2008, letter from Douglas Scott, Director, Illinois Environmental Protection Agency, submitting the Illinois recommendations on air quality designations for the 2006 24-hour $PM_{2.5}$ standards. We have also reviewed the technical information submitted to support the Illinois recommendations. We appreciate the effort your State has made to develop this supporting information. Consistent with the Clean Air Act, this letter is to inform you that the U.S. Environmental Protection Agency intends to make modifications to the designations and boundaries recommended by Illinois.

We have enclosed a detailed description of areas where EPA intends to modify your state recommendations, and the basis for such modifications. Your Environmental Director will also receive a copy of this letter and the enclosure. Should you have additional information that you wish EPA to consider in this process, please provide it to us by October 20, 2008.

EPA has taken steps to reduce fine particle pollution across the country, such as the Clean Diesel Program, which we expect to dramatically reduce emissions from highway, non-road and stationary diesel engines. In addition, State programs to attain the 1997 $PM_{2.5}$ standards will help to reduce unhealthy levels of fine particle pollution.

We intend to make final designation decisions for the 2006 24-Hour $PM_{2.5}$ standards by December 18, 2008. Please also be aware that EPA plans to publish a notice in the Federal Register in the near future in order to solicit public comments on our intended designation decisions. If you have any questions, please do not hesitate to contact me. We look forward to a continued dialogue with you as we work together to implement the $PM_{2.5}$ standards.

Sincerely,

Lynn Buhl

Lynn Buhl
Regional Administrator

Enclosure

cc: Douglas P. Scott
Director
Illinois Environmental Protection Agency

Review of Designations in Illinois
For the Particulate Matter Air Quality Standard

The table below identifies the counties in Illinois that EPA intends to designate as not attaining the 2006 24-hour fine particle (PM2.5) standard.[1] A county will be designated as nonattainment if it has an air quality monitor that is violating the standard or if the county is determined to be contributing to the violation of the standard.

Where EPA intends to include only part of a county in a nonattainment area, we have indicated the boundaries of the portion of the county that will be included. Following this table is a discussion of each area and the basis for EPA's intended designations and then a description of the data EPA examined. EPA intends to designate as attainment/ unclassifiable all other Illinois counties or parts thereof not identified in the table below.

Area	Current $PM_{2.5}$ Nonattainment Area	Illinois Recommended Nonattainment Counties	EPA's Intended Nonattainment Counties
Chicago-Gary-Kenosha, IL-IN-WI	Cook Du Page Kane Lake Mc Henry Will Grundy: Aux Sable Township Goose Lake Twp. Kendall: Oswego Township	Cook Du Page Kane Lake Mc Henry Will Grundy: Aux Sable Township Goose Lake Township Kendall: Oswego Township	Cook Du Page Kane Lake Mc Henry Will Grundy: Aux Sable Township Goose Lake Township Kendall: Oswego Township
Davenport-Rock Island, IA-IL	None	None	Rock Island
Paducah, KY-IL	None	None	Massac
Saint Louis, MO-IL	Madison Monroe St Clair Randolph: Baldwin Township	Madison Monroe St Clair Randolph: Baldwin Township*	Madison Monroe St Clair Randolph: Baldwin Township

* Illinois recommended a slightly smaller partial county area, excluding a portion of Baldwin Township from the nonattainment area. EPA intends to retain the entire Baldwin Township in the nonattainment area.

[1] EPA designated nonattainment areas for the 1997 fine particle standards in 2005. In 2006, the 24-hour PM2.5 standard was revised from 65 micrograms per cubic meter (average of 98th percentile values for 3 consecutive years) to 35 micrograms per cubic meter; the level of the annual standard for PM2.5 remained unchanged at 15 micrograms per cubic meter (average of annual averages for 3 consecutive years).

On June 8, 2007, in a memorandum from Robert Meyers to the EPA Regional Administrators, EPA issued guidance on a timetable for designation of areas violating the PM2.5 air quality standards promulgated in 2006 and factors that EPA urged states to consider as they prepared recommendations for nonattainment area boundaries. This guidance was sent to the Governor of Illinois as an attachment to a letter dated July 9, 2007, requesting the State's recommendations.

Pursuant to section 107(d) of the Clean Air Act, EPA must designate as nonattainment those areas that violate the NAAQS and those areas that contribute to violations. The technical analysis for each area identifies the counties with monitors that violate the 24-hour PM2.5 standard and evaluates the counties that potentially contribute to fine particle concentrations in the area. EPA has evaluated these counties based on the weight of evidence of the following nine factors recommended in EPA guidance and any other relevant information:

- pollutant emissions
- air quality data
- population density and degree of urbanization
- traffic and commuting patterns
- growth
- meteorology
- geography and topography
- jurisdictional boundaries
- level of control of emissions sources

Additional background information on each of the nine factors can also be found in the background section below.

EPA also computed a Contributing Emissions Score (CES) for each county. The CES is a metric that takes into consideration emissions data, meteorological data, and air quality monitoring information to provide a relative ranking of potential impacts of counties in and near an area on violating monitors. While this metric provides a useful synthesis of important relevant information, including weighting the emissions of various pollutants according to estimates of the relative importance of each pollutant, the CES is not the exclusive variable EPA uses to consider these factors. A summary of the CES is included in the background section, and a more detailed description can be found at http://www.epa.gov/ttn/naaqs/pm/pm25_2006_techinfo.html#C.

Review for the Illinois Portion of the Chicago-Gary-Kenosha, IL-IN-WI Metropolitan Area

Discussion:
EPA reviewed relevant information for the ten counties (including eight counties in Illinois) partly or fully within the area designated nonattainment for the 1997 standards as well as for surrounding counties. There are violating monitors in Cook and Will Counties and in Lake County, Indiana. Illinois recommended a definition of the

nonattainment area for the 2006 standards that reflects the same boundaries within Illinois as were established for the 1997 standards, including (within Illinois) Cook, Du Page, Kane, Lake, Mc Henry, and Will counties, Aux Sable and Goose Lake Townships in Grundy County, and Oswego Township in Kendall County. EPA agrees with this recommendation.

EPA also examined information for other counties within and adjacent to the Combined Statistical Area as well as for adjacent counties. The bulk of emissions and population are captured without including DeKalb, Grundy, Kankakee and Kendall Counties, since these counties have limited emissions and population. Nevertheless, we support the recommendation by the Illinois EPA to include the three townships in Grundy and Kendall counties in the nonattainment area to maintain consistency with the ozone designations and the prior $PM_{2.5}$ designations and thereby facilitate planning, as well as to include slightly more emissions in the planning area.

Emissions for other surrounding counties are relatively low, and no other factor warranted designating these other counties nonattainment.

Figure 1 is a map of the counties in the area and other relevant information such as the locations and design values of air quality monitors, the metropolitan area boundary, and counties recommended as nonattainment by the States.

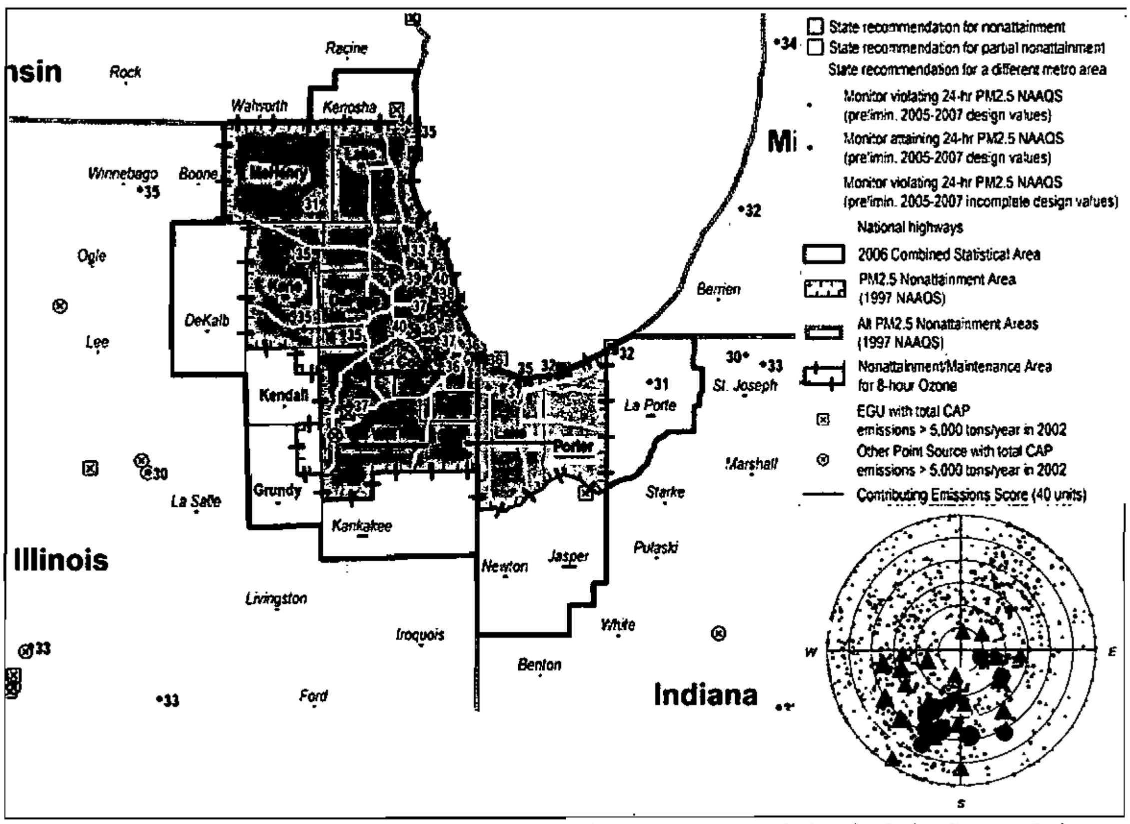

Figure 1- Note: Map produced prior to Indiana's nonattainment recommendation for Lake County, Ind.

Factor 1: Emissions data

Table 1 shows emissions of $PM_{2.5}$ components (given in tons per year) and the CESs for potentially contributing counties in the Chicago area. Counties that are part of the Chicago nonattainment area for the 1997 $PM_{2.5}$ NAAQS are shown in boldface. Counties are listed in descending order by CES.

Table 1. $PM_{2.5}$ 24-hour Component Emissions, and CESs.

County	State Recommended Nonattainment?	CES	$PM_{2.5}$ emissions total (tpy)	$PM_{2.5}$ emissions carbon (tpy)	$PM_{2.5}$ emissions other (tpy)	SO_2 (tpy)	NOx (tpy)	VOCs (tpy)	NH_3 (tpy)
Cook, IL	**Yes**	**100**	**10,081**	**5,407**	**4,674**	**35,354**	**175,267**	**152,288**	**4,550**
Lake, IN	**No**	**100**	**7,079**	**1,219**	**5,861**	**39,500**	**54,203**	**24,679**	**3,784**
Will, IL	**Yes**	**95**	**5,432**	**1,236**	**4,195**	**78,792**	**46,028**	**19,886**	**1,407**
Porter, IN	**No**	**41**	**3,901**	**719**	**3,183**	**24,458**	**29,930**	**9,795**	**909**
DuPage, IL	**Yes**	**16**	**2,075**	**1,259**	**816**	**2,013**	**36,880**	**29,541**	**1,385**
Jasper, IN	No	14	2,641	280	2,360	40,723	20,104	3,367	2,929
Kankakee, IL	No	9	1,660	419	1,242	366	7,351	6,830	1,699
Kane, IL	**Yes**	**4**	**1,997**	**733**	**1,263**	**1,037**	**16,528**	**15,578**	**1,293**
Grundy, IL	**Partial**	**3**	**1,105**	**248**	**857**	**362**	**4,057**	**4,223**	**1,027**
Lake, IL	**Yes**	**3**	**2,657**	**1,070**	**1,587**	**14,719**	**29,478**	**32,778**	**747**
Kendall, IL	**Partial**	**2**	**811**	**230**	**581**	**351**	**3,697**	**3,693**	**753**
McHenry, IL	**Yes**	**1**	**2,102**	**634**	**1,468**	**592**	**9,493**	**10,596**	**1,224**
Kenosha, WI	No	1	1,489	460	1,030	33,988	15,967	7,857	647

Within Illinois, emissions are highest in Cook, Will, DuPage, Lake, Kane, and McHenry Counties. Emissions are moderate in Kankakee, Grundy, and Kendall Counties.

Factor 2: Air quality data

The 24-hour $PM_{2.5}$ design values for counties in the Chicago area are shown in Table 2.

Table 2. Air Quality Data

County	State Recommended Nonattainment?	Design Values 2004-06 ($\mu g/m^3$)	Design Values 2005-07 ($\mu g/m^3$)
Cook, IL	Yes	42	40
Lake, IN	No	38	37
Will, IL	Yes	36	37
Porter, IN	No	31	32
DuPage, IL	Yes	33	35
Kane, IL	Yes	32	35
Grundy, IL	Partial		
Lake, IL	Yes	33	35
Kendall, IL	Partial		
McHenry, IL	Yes	31	31

For purposes of its review, EPA used data available from the Chemical Speciation Network and the Interagency Monitoring of Protected Visual Environments (IMPROVE) network to estimate the composition of fine particle mass on days with the highest fine particle concentrations. On high concentration days during cold weather months in this area, EPA found on average a total urban contribution of 8.8 $\mu g/m^3$, consisting of 0.4 $\mu g/m^3$ of sulfate, no nitrate, 8.4 $\mu g/m^3$ of organic particles, and no miscellaneous inorganic particulate. On high concentration days during warm weather months in this area, EPA found on average a total urban contribution of 3.9 $\mu g/m^3$, consisting of 0.5 $\mu g/m^3$ of sulfate, 3.1 $\mu g/m^3$ of organic particles, and 0.3 $\mu g/m^3$ of miscellaneous inorganic particulate. These estimates were used for weighting of the emissions of different pollutants in calculating the contributing emissions scores.

Factor 3: Population density and degree of urbanization (including commercial development)

Table 3 shows the 2005 population for each county in the area being evaluated, as well as the population density for each county in that area. Population data give an indication of whether it is likely that population-based emissions might contribute to violations of the 24-hour $PM_{2.5}$ standards.

Table 3. Population

County	State Recommended Nonattainment?	2005 Population	2005 Population Density (pop/sq mi)
Cook, IL	Yes	5,303,943	5545
Lake, IN	No	491,706	980
Will, IL	Yes	642,625	758
Porter, IN	No	157,408	375
DuPage, IL	Yes	931,219	2769
Kane, IL	Yes	483,208	923
Grundy, IL	Partial	43,736	102
Lake, IL	Yes	704,086	1504
Kendall, IL	Partial	79,597	247
McHenry, IL	Yes	304,701	499
Kankakee	No	107,824	158

Within Illinois, the counties with the greatest population are Cook, DuPage, Lake, Will, Kane, and McHenry Counties. The populations and population densities of Kankakee, Grundy, and Kendall Counties are significantly lower.

Factor 4: Traffic and commuting patterns

Table 4. Traffic and Commuting Patterns

County	State Recommended Nonattainment?	2005 VMT (10^6 mi)	Number Commuting to any violating counties	Percent Commuting to any violating counties	Number Commuting into statistical area	Percent Commuting into statistical area
Cook, IL	**Yes**	**35,294**	**2,113,930**	**89**	**2,352,120**	**99**
Lake, IN	**No**	**4,588**	**193,610**	**93**	**206,350**	**99**
Will, IL	**Yes**	**4,605**	**185,690**	**77**	**239,340**	**99**
Porter, IN	**No**	**1,677**	**25,470**	**35**	**70,940**	**98**
DuPage, IL	**Yes**	**8,802**	**161,940**	**35**	**464,630**	**99**
Kane, IL	**Yes**	**3,517**	**36,290**	**19**	**190,780**	**99**

Grundy, IL	**Partial**	**623**	**6,990**	**38**	**17,310**	**95**
Lake, IL	**Yes**	**6,016**	**83,930**	**26**	**313,250**	**99**
Kendall, IL	**Partial**	**678**	**4,230**	**15**	**27,860**	**99**
McHenry, IL	**Yes**	**2,104**	**31,680**	**24**	**130,520**	**98**

The listing of counties on Table 4 reflects a ranking based on the number of people commuting to other counties. The counties that are in the nonattainment area for the 1997 $PM_{2.5}$ NAAQS are shown in boldface. All counties in this table are highly integrated into the Chicago area.

Factor 5: Growth rates and patterns

Table 5 below shows population, population growth, VMT and VMT growth for counties that are included in the Chicago area. Counties are listed in descending order based on VMT growth between 1996 and 2005.

Table 5. Population and VMT Growth and Percent Change.

County	Population (2005)	Population % change (2000-05)	2005 VMT (10^6 mi)	VMT % change (1996-05)
Kane, IL	483,208	18	3,517	364
McHenry, IL	304,701	16	2,104	196
Kendall, IL	79,597	44	678	166
Will, IL	642,625	26	4,605	135
Lake, IL	704,086	9	6,016	82
DuPage, IL	931,219	3	8,802	43
Grundy, IL	43,736	16	623	30
Porter, IN	157,408	7	1,677	10
Lake, IN	491,706	1	4,588	0
Cook, IL	5,303,943	-1	35,294	-14

The growth rates are not expected to yield significant changes in the distribution of population in the area, so this factor did not significantly influence the decision-making process.

Factor 6: Meteorology (weather/transport patterns)

The pollution rose for the Chicago area is provided in the map above. Winds on high concentration days predominantly come from the southwest and southeast, but it is appropriate to include counties in all directions from the violations.

Factor 7: Geography/topography (mountain ranges or other air basin boundaries)

The Chicago area does not have any geographical or topographical barriers significantly limiting air-pollution transport within its air shed. Therefore, this factor did not play a significant role in the decision-making process.

Factor 8: Jurisdictional boundaries (e.g., existing PM and ozone areas)

The Chicago Area Transportation Study (CATS) Policy Committee is the Metropolitan Planning Organization (MPO) for the northeastern Illinois region. CATS webpage: http://www.catsmpo.com/.

The Illinois portion of the Chicago ozone nonattainment area consists of the following counties: Cook, Du Page, Kane, Lake, Mc Henry, Will, Aux Sable and Goose Lake Townships in Grundy County, and Oswego Township in Kendall County. Designating a nonattainment area matching these boundaries will facilitate planning.

Factor 9: Level of control of emission sources

The emission estimates on Table 1 include any control strategies implemented by the States in the Chicago area before 2005 that may influence emissions of any component of $PM_{2.5}$ emissions (i.e., total carbon, SO_2, NOx, and crustal $PM_{2.5}$).

Review for the Davenport-Moline-Rock Island Metropolitan Statistical Area

Discussion:
The Davenport-Moline-Rock Island area is currently designated attainment for $PM_{2.5}$. A monitor in Davenport (Scott County) is showing violations of the standard. Illinois recommended including no part of Illinois in the nonattainment area. EPA reviewed relevant information for the four counties in the metropolitan statistical area and for surrounding counties.

EPA believes that the nonattainment area should include Rock Island County in Illinois. Rock Island County has moderate emissions that commonly are blown toward the violating monitor is Scott County. We also believe that sufficient commuting occurs between Rock Island County and Scott County that Rock Island County must be considered an integral part of the Davenport area.

EPA recognizes that emissions in close proximity to the monitor may make an important contribution to the violations. Indeed, EPA recognizes the possibility that reduction of the emissions close to the monitor may suffice to address the violation. Nevertheless, our obligation under Clean Air Act section 107 in defining a nonattainment area is to identify the area that is violating the standard and the area that is contributing to the violation. The area that contributes to the violation is then included in the planning area evaluated for measures for attaining the standard. Even if the state already suspects that its control strategy will focus on sources in the immediate vicinity of the violating monitor, EPA must apply a nonattainment designation to the entire area that contributes to the violation, such that the SIP planning will address the entire contributing area.

Furthermore, the available evidence suggests that local emissions contribute only a fraction of the concentrations in Davenport. A much larger fraction of the concentrations in Davenport arise from emissions farther from the monitor. EPA believes that an important component of these concentrations arises from a contribution from emissions throughout the Quad Cities area. While the impact of Rock Island County appears to be less than that of Scott Counties, Iowa, the impact nevertheless appears sufficiently substantial to include Rock Island County in the nonattainment area.

EPA also examined information for Henry and Mercer Counties as well as for nearby counties outside the metropolitan area. EPA found that these other counties have relatively low emissions, and no other factor warranted inclusion of the counties in the nonattainment area.

Figure 2 is a map of the counties in the area and other relevant information such as the locations and design values of air quality monitors, the metropolitan area boundary. Iowa did not make formal recommendations, and Illinois recommended that no Illinois counties be included, so this map shows no state recommended nonattainment area.

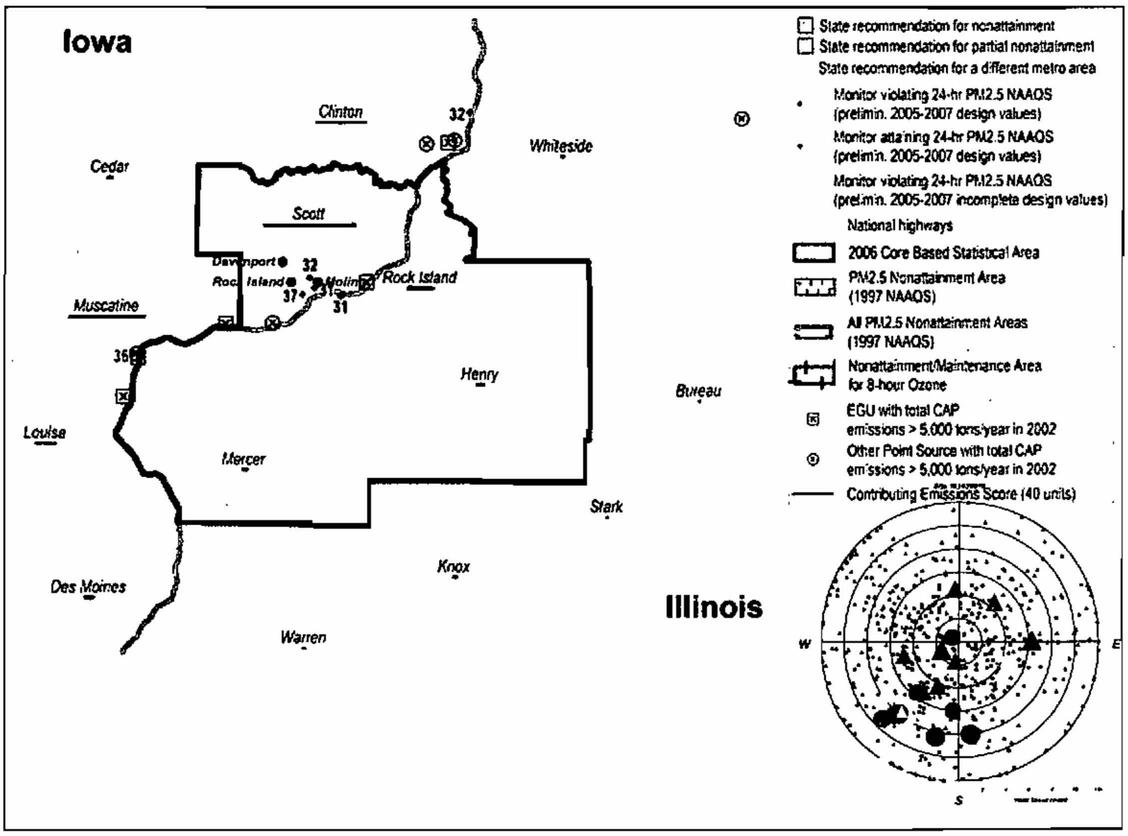

Figure 2

Factor 1: Emissions data

Table 1 shows emissions of $PM_{2.5}$ components (given in tons per year) and the CESs for potentially contributing counties in the Quad Cities area. Counties are listed in descending order by CES.

Table 1. $PM_{2.5}$ 24-hour Component Emissions, and CESs.

County	State Recommended Nonattainment?	CES	$PM_{2.5}$ emissions total (tpy)	$PM_{2.5}$ emissions carbon (tpy)	$PM_{2.5}$ emissions other (tpy)	SO_2 (tpy)	NOx (tpy)	VOCs (tpy)	NH_3 (tpy)
Scott, IA	No recommendation	100	2,034	395	1,639	9,173	11,317	9,323	1,986
Muscatine, IA	No recommendation	80	1,702	283	1,419	27,020	10,717	4,910	1,083
Clinton, IA	No	52	2,711	354	2,357	11,506	13,217	11,503	4,870
Rock Island, IL	No	27	932	269	663	2,169	6,140	7,359	664
Henry, IL	No	7	1,273	252	1,021	268	6,648	3,431	2,805
Mercer, IL	No	4	793	149	644	133	1,120	1,469	1,026

Rock Island County has a substantial fraction of the area's emissions.

Factor 2: Air quality data

The 24-hour $PM_{2.5}$ design values for counties in the Quad Cities area are shown in Table 2.

Table 2. Air Quality Data

County	State Recommended Nonattainment?	Design Values 2004-06 ($\mu g/m^3$)	Design Values 2005-07 ($\mu g/m^3$)
Scott, IA	No recommendation	32	37
Rock Island, IL	No	30	31
Henry, IL	No		
Mercer, IL	No		
Muscatine, IA	No recommendation	34	36
Clinton, IA	No recommendation	34	32

For purposes of its review, EPA used data available from the Chemical Speciation Network and the Interagency Monitoring of Protected Visual Environments (IMPROVE) network to estimate the composition of fine particle mass on days with the highest fine particle concentrations. On high concentration days during cold weather months in this area, EPA found on average a total urban contribution of 7.1 $\mu g/m^3$, consisting of 2.0 $\mu g/m^3$ of sulfate, 2.5 $\mu g/m^3$ of nitrate, 2.3 $\mu g/m^3$ of organic particles, and 0.3 $\mu g/m^3$ of miscellaneous inorganic particulate. On high concentration days during warm weather months in this area, EPA found on average a total urban contribution of 4.3 $\mu g/m^3$, consisting of 3.9 $\mu g/m^3$ of sulfate and 0.4 $\mu g/m^3$ of organic particulate emissions. These estimates were used for weighting of the emissions of different pollutants in calculating the contributing emissions scores.

Factor 3: Population density and degree of urbanization (including commercial development)

Table 3 shows the 2005 population for each county in the area being evaluated, as well as the population density for each county in that area. Population data give an indication of whether it is likely that population-based emissions might contribute to violations of the 24-hour $PM_{2.5}$ standards.

Table 3. Population

County	State Recommended Nonattainment?	2005 Population	2005 Population Density (pop/sq mi)
Scott, IA	No recommendation	161,170	345
Rock Island, IL	No	147,454	327
Henry, IL	No	50,508	61
Mercer, IL	No	16,840	30
Muscatine, IA	No recommendation	42,567	95
Clinton, IA	No recommendation	49,744	70

Rock Island County has a substantial fraction of the area's population. Other Illinois counties have substantially lower populations.

Factor 4: Traffic and commuting patterns

Table 4. Traffic and Commuting Patterns

County	State Recommended Nonattainment?	2005 VMT (10^6 mi)	Number Commuting to any violating counties	Percent Commuting to any violating counties	Number Commuting into statistical area	Percent Commuting into statistical area
Scott, IA	No recommendation	1,614	61,500	79	74,020	95
Rock Island, IL	No	1,313	14,240	20	67,530	97
Henry, IL	No	695	1,870	8	22,340	91
Mercer, IL	No	135	1,200	15	6,570	85
Clinton, IA	No recommendation	423	2,610	11	3,600	15
Muscatine, IA	No recommendation	372	17,330	85	1,060	5

The listing of counties on Table 4 reflects a ranking based on the number of people commuting to other counties. The percentage of Rock Island County commuters commuting into Scott County, Iowa, is moderate but sufficient to view Rock Island County as integrated into a Quad Cities area.

Factor 5: Growth rates and patterns

Table 5 below shows population, population growth, VMT and VMT growth for counties that are included in the Quad Cities area. Counties are listed in descending order based on VMT growth between 1996 and 2005.

Table 5. Population and VMT Growth and Percent Change.

Location	Population (2005)	Population % change (2000-05)	2005 VMT (10^6 mi)	VMT % change (1996-2005)
Muscatine, IA	42,567	2	372	43
Clinton, IA	49,744	-1	423	39

Scott, IA	161,170	2	1,614	25
Henry, IL	50,508	-1	695	7
Rock Island, IL	147,454	-1	1,313	3
Mercer, IL	16,840	-1	135	-12

The growth rates are not likely to yield significant changes in the distribution of population during the SIP planning time horizon.

Factor 6: Meteorology (weather/transport patterns)

The pollution rose for the Quad Cities area is provided in the map above. The pollution rose for this area suggests that Rock Island County is upwind of Davenport on most high concentration days.

Factor 7: Geography/topography (mountain ranges or other air basin boundaries)

The Quad Cities area does not have any geographical or topographical barriers significantly limiting air-pollution transport within its air shed. Therefore, this factor did not play a significant role in the decision-making process.

Factor 8: Jurisdictional boundaries (e.g., existing PM and ozone areas)

Bi-State Regional Commission represents the Metropolitan Planning Organization (MPO) for urbanized area transportation planning in the Quad Cities area. The MPO serves Henry, Mercer, and Rock Island Counties in Illinois and Scott and Muscatine Counties in Iowa. Its web site is: **www.bistateonline.org**. This suggests that the MPO is already engaged in multi-county planning, which would facilitate multi-county SIP planning.

Factor 9: Level of control of emission sources

The emission estimates on Table 1 include any control strategies implemented by the States in the Quad Cities area before 2005 that may influence emissions of any component of $PM_{2.5}$ emissions (i.e., total carbon, SO_2, NOx, and crustal $PM_{2.5}$).

Review for the Paducah-Mayfield Combined Statistical Area

The only monitor in the Paducah-Mayfield area is in McCracken County, Kentucky. Kentucky requested concurrence on several claims that elevated concentrations were attributable to exceptional events, in particular due to wildfires. EPA reviewed this request, denied some of these claims, and concluded that the Paducah area is violating the 24-hour $PM_{2.5}$ standard.

The Paducah-Mayfield combined statistical area includes one county in Illinois: Massac County. This county has a relatively high fraction of the emissions in the area, and the winds commonly blow from Massac County into McCracken County on high concentration days. A substantial fraction of the Massac County emissions are attributable to the Joppa Steam Plant.

In considering county-level emissions, EPA considered 2005 emissions data from the National Emissions Inventory. EPA recognizes that the Joppa Steam Plant may have installed emission controls or otherwise significantly reduced emissions since 2005 and that this information may not be reflected in this analysis. EPA will consider additional information on emission controls in making final designation decisions. In cases where specific plants already have installed emission controls or plan to install such controls in the near future, EPA requests additional information on:

- the plant name, city, county, and township
- identification of emission units at the plant, fuel use, and megawatt capacity
- identification of emission units on which controls will be installed, and units on which controls will not be installed
- identification of the type of emission control that has been or will be installed on each unit, the date on which the control device became / will become operational, and the emission reduction efficiency of the control device
- the estimated pollutant emissions for each unit before and after implementation of emission controls
- whether the requirement to operate the emission control device will be federally enforceable by December 2008, and the instrument by which federal enforceability will be ensured (e.g. through source-specific SIP revision, operating permit requirement, consent decree)

In the designation process for the 1997 PM2.5 standards, in some cases EPA identified a nearby county as contributing to a violating monitor, and it was determined that a very high percentage of the county's emissions came from a large power plant. In certain cases, EPA concluded that only the portion of the county including the source with the contributing emissions needed to be designated as nonattainment. If Illinois believes that a similar situation exists for Massac County, the State should provide EPA the necessary information to demonstrate that the source dominates the overall county emissions and to identify a reasonable partial county boundary.

In its designations for the 1997 standards, EPA included portions of counties in a number of cases in which large sources dominated the emissions from the county, such that EPA concluded that the relevant portion of the county was the only portion of the county that contributed to the violations. If Illinois believes this is the case in Massac County, for example if Illinois believes that only a single township containing the Joppa Steam plant contributes to violations in Paducah, Illinois should provide the information necessary to support this view.

EPA also examined information for other Illinois counties around the Paducah-Mayfield area. These other counties have relatively low emissions, and no other factor warrants their inclusion in the Paducah-Mayfield nonattainment area.

Figure 3 is a map of the counties in the area and other relevant information such as the locations and design values of air quality monitors, the metropolitan area boundary. Kentucky recommended that Paducah be found to be attaining the standard, and Illinois recommended that no Illinois counties be included if in fact the area was found to be violating, so this map shows no state recommended nonattainment area.

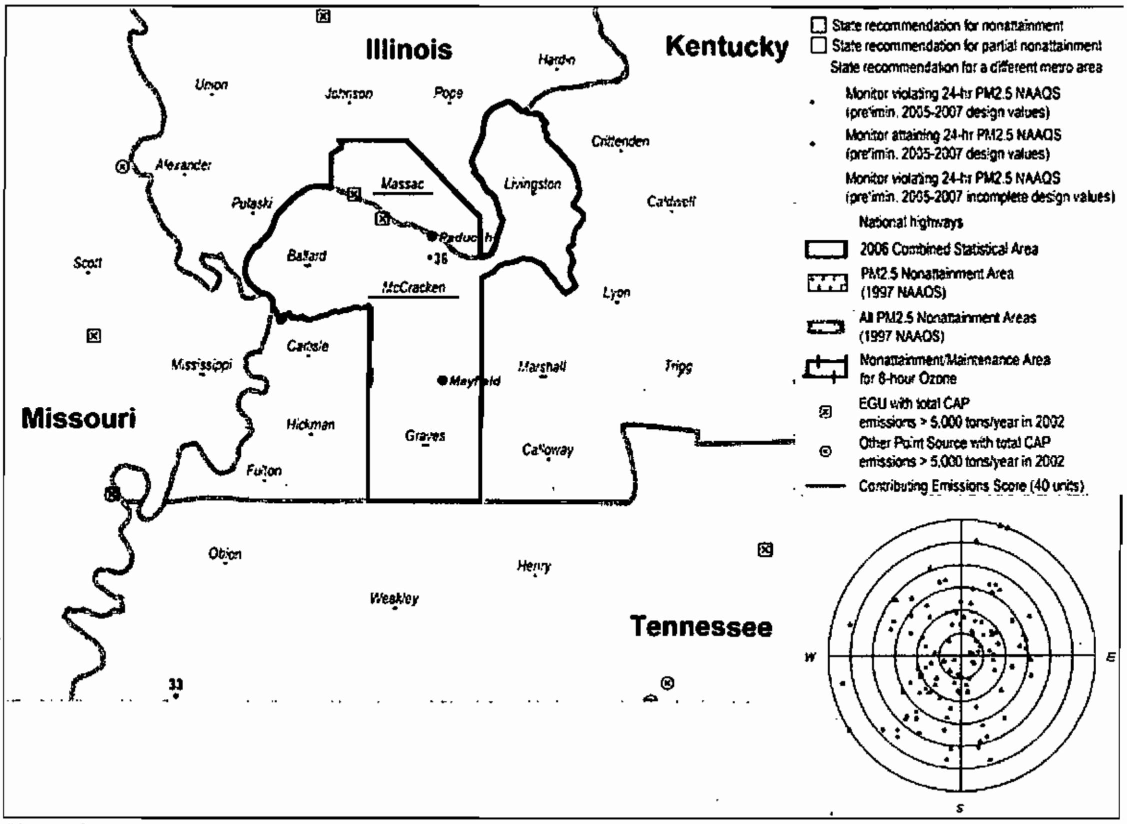

Figure 3

Factor 1: Emissions data

Table 1 shows emissions of $PM_{2.5}$ components (given in tons per year) and the CESs for potentially contributing counties in the Paducah area. Counties are listed in descending order by CES.

Table 1. $PM_{2.5}$ 24-hour Component Emissions, and CESs.

County	State Recommended Nonattainment?	CES	$PM_{2.5}$ emissions total (tpy)	$PM_{2.5}$ emissions carbon (tpy)	$PM_{2.5}$ emissions other (tpy)	SO_2 (tpy)	NOx (tpy)	VOCs (tpy)	NH_3 (tpy)
McCracken, KY	No	100	1,339	293	1,046	38,956	24,803	6,661	366
Massac, IL	No	66	1,958	159	1,799	26,884	12,369	2,612	417
Graves, KY	No	6	797	278	520	413	1,735	1,867	2,538
Ballard, KY	No	5	596	140	456	927	2,785	1,661	855
Livingston, KY	No	3	318	121	197	337	2,155	1,200	239

McCracken and Massac Counties have substantially greater emissions than any other nearby county.

Factor 2: Air quality data

The 24-hour $PM_{2.5}$ design values for counties in the Paducah area are shown in Table 2. The design value of McCracken County, Kentucky is above the 2006 $PM_{2.5}$ standard. There is no $PM_{2.5}$ air quality data for the other area counties.

Table 2. Air Quality Data

County	State Recommended Nonattainment?	Design Values 2004-06 (μg/m^3)	Design Values 2005-07 (μg/m^3)
McCracken, KY	No	33	36
Massac, IL	No		
Graves, KY	No		
Ballard, KY	No		
Livingston, KY	No		

For purposes of its review, EPA used data available from the Chemical Speciation Network and the Interagency Monitoring of Protected Visual Environments (IMPROVE) network to estimate the composition of fine particle mass on days with the highest fine particle concentrations. On high concentration days during cold weather months in this area, EPA found on average a total urban contribution of 4.3 μg/m^3, consisting of 0.9 μg/m^3 of sulfate, 2.2 μg/m^3 of nitrate, 1.2 μg/m^3 of organic particles, and no miscellaneous inorganic particulate. On high concentration days during warm weather months in this area, EPA found on average a total urban contribution of 5.2 μg/m^3, consisting of 3.0 μg/m^3 of sulfate and 2.2 μg/m^3 of organic particulate emissions. These estimates were used for weighting of the emissions of different pollutants in calculating the contributing emissions scores.

Factor 3: Population density and degree of urbanization (including commercial development)

Table 3 shows the 2005 population for each county in the area being evaluated, as well as the population density for each county in that area. Population data give an indication of whether it is likely that population-based emissions might contribute to violations of the 24-hour $PM_{2.5}$ standards.

Table 3. Population

County	State Recommended Nonattainment?	2005 Population	2005 Population Density (pop/sq mi)
McCracken, KY	No	64,690	241
Massac, IL	No	15,225	63
Graves, KY	No	37,650	68
Ballard, KY	No	8,262	30

Livingston, KY	No	9,783	29

McCracken County has most of the area's population; the population of Massac County is not a significant factor in determining the nonattainment area boundaries.

Factor 4: Traffic and commuting patterns

Table 4. Traffic and Commuting Patterns

County	State Recommended Nonattainment?	2005 VMT (10^6 mi)	Number Commuting to any violating counties	Percent Commuting to any violating counties	Number Commuting into statistical area	Percent Commuting into statistical area
McCracken, KY	No	832	24,200	84	26,830	93
Graves, KY	No	435	2,350	15	12,880	83
Massac, IL	No	225	1,950	30	5,860	90
Livingston, KY	No	174	1,770	41	3,580	82
Ballard, KY	No	102	1,290	35	3,380	92

The listing of counties on Table 4 reflects a ranking based on the number of people commuting to other counties. A modest number of people from Massac County commute into McCracken County.

Factor 5: Growth rates and patterns

Table 5 below shows population, population growth, VMT and VMT growth for counties that are included in the Paducah area. Counties are listed in descending order based on VMT growth between 1996 and 2005.

Table 5. Population and VMT Growth and Percent Change.

County	Population (2005)	Population % change (2000-05)	2005 VMT (10^6 mi)	VMT % change (1996-2005)
McCracken, KY	64,690	-1	832	26
Massac, IL	15,225	1	225	25
Graves, KY	37,650	2	435	21
Ballard, KY	8,262	-1	102	12
Livingston, KY	9,783	0	174	56

The growth rates are not expected to change the population distribution of the area significantly during the SIP planning time horizon.

Factor 6: Meteorology (weather/transport patterns)

A pollution rose for the Paducah area is provided in the map above. Both the pollution roses and the trajectory frequency information suggest that emissions from the full range of directions, including from the direction of Massac County, contribute to PM2.5 on high concentration days in Paducah.

Factor 7: Geography/topography (mountain ranges or other air basin boundaries)

The Paducah area does not have any geographical or topographical barriers significantly limiting air-pollution transport within its air shed. Therefore, this factor did not play a significant role in the decision-making process.

Factor 8: Jurisdictional boundaries (e.g., existing PM and ozone areas)

The Paducah maintenance area from its former one-hour ozone designation was comprised of Livingston and Marshall Counties in Kentucky. No portion of Illinois was in the Paducah ozone nonattainment area.

Factor 9: Level of control of emission sources

The emission estimates on Table 1 include any control strategies implemented by the States in the Paducah area before 2005 that may influence emissions of any component of $PM_{2.5}$ emissions (i.e., total carbon, SO_2, NOx, and crustal $PM_{2.5}$).

Review for the Saint Louis Combined Statistical Area

Discussion:

EPA reviewed relevant information for the nine counties (including four counties in Illinois) partly or fully within the area designated nonattainment for the 1997 standards as well as for surrounding counties. There are violating monitors in Madison County. Illinois recommended a definition of the nonattainment area for the 2006 standards that is similar to the boundaries that were established for the 1997 standards, including Madison, Monroe and St. Clair Counties along with a portion of Randolph County. Illinois recommended that the nonattainment area for the 2006 standards differ from the nonattainment area for the 1997 standards by the exclusion of the portion of Baldwin Township in Randolph County that is west of the Kaskaskia River.

EPA concurs with Illinois's recommendation to include Madison, Monroe, and St. Clair Counties in the St. Louis nonattainment area. However, EPA believes that all of Baldwin Township of Randolph County should be included as well. The most important factor influencing this judgment is the factor relating to jurisdictional boundaries. The inclusion of a full township will make nonattainment requirements easier to administer, since information on emissions and source locations are more readily available on a township basis than with respect to a specially defined subset of the township. Furthermore, EPA believes that establishment of a nonattainment area that fully matches the nonattainment area established for the 1997 standards would simplify nonattainment planning by assuring that identical requirements apply for an identical area. At the same time, as addressed in more detail in our documentation of our designations for the 1997 standards, Baldwin Township contains almost all of the emissions and therefore makes almost the entirety of the contribution of Randolph County to the violations, so that a designation of just Baldwin Township as nonattainment will suffice to address the contribution of this portion of the area.

In considering county-level emissions, EPA considered 2005 emissions data from the National Emissions Inventory. EPA has signed a consent decree that requires Dynegy to install and operate highly effective SO_2 control equipment at its Baldwin power plant by the end of 2010, 2011, and 2012 for its first, second, and third unit installations, respectively. EPA notes that these dates are between 2 and 4 years after the time we are judging what areas contribute to nonattainment. The company has already installed effective NOx control equipment. EPA welcomes any further relevant information that Illinois may have. EPA will consider additional information on emission controls in making final designation decisions. In cases where specific plants already have installed emission controls or plan to install such controls in the near future, EPA requests additional information on:

- the plant name, city, county, and township
- identification of emission units at the plant, fuel use, and megawatt capacity
- identification of emission units on which controls will be installed, and units on which controls will not be installed
- identification of the type of emission control that has been or will be installed on each unit, the date on which the control device became / will become operational, and the emission reduction efficiency of the control device
- the estimated pollutant emissions for each unit before and after implementation of emission controls
- whether the requirement to operate the emission control device will be federally enforceable by December 2008, and the instrument by which federal enforceability will be ensured (e.g. through source-specific SIP revision, operating permit requirement, consent decree)

EPA reviewed the relevant information for other counties within the combined statistical area as well as counties adjacent to the combined statistical area in order to determine the appropriate nonattainment area. Sangamon County has moderate emissions but is rarely upwind on days with elevated 24-hour $PM_{2.5}$ concentrations. Other Illinois counties in or near the combined statistical area have relatively low emissions, and no other factor warranted inclusion of the counties in the nonattainment area.

Figure 4 is a map of the counties in the area and other relevant information such as the locations and design values of air quality monitors, the metropolitan area boundary, and the counties recommended as nonattainment by the states.

 IEPA ATTACHMENT NO. 2

Progress Energy

OFFICIAL COPY

March 31, 2008

FILED
MAR 31 2008
Clerk's Office
N.C. Utilities Commission

Ms. Renne Vance
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

Re: Annual NC Clean Smokestacks Act Compliance Report
Docket No. E-2, Sub 815

Dear Ms. Vance:

Progress Energy Carolinas, Inc. submits the attached report for calendar year 2007 regarding the status of compliance with the provisions of the North Carolina Clean Smokestacks Act. Section 9(i) of the Act requires that an annual report of compliance progress be submitted to the Commission by April 1 of each year for the previous calendar year.

Very truly yours,

Len S. Anthony (by dhs)
Len S. Anthony
General Counsel-Progress Energy Carolinas

LSA:mhm

Attachment

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Clerk's
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Mailed to
Ross
Overcash
Givens
Goldsmith
Rose

Progress Energy Service Company, LLC
P.O. Box 1551
Raleigh, NC 27602

Progress Energy **OFFICIAL COPY**

March 31, 2008

Mr. William G. Ross, Jr.
Secretary
North Carolina Department of Environment and Natural Resources
1601 Mail Service Center
Raleigh, NC 27699-1601

Dear ~~Secretary Ross~~: Bill –

Progress Energy Carolinas, Inc. (PEC, Company) submits the attached report for calendar year 2007 regarding the status of its compliance with the provisions of the North Carolina Clean Smokestacks Act (Act).

As you know, 2007 was a significant year for the Clean Smokestacks Act – the first year in which the nitrogen oxides (NOx) emissions cap became effective. During 2007, we completed installation of the NOx controls necessary to meet our limit. As the report shows, the Company's annual NOx emissions from its North Carolina coal-fired units totaled less than 25,000 tons. We have developed plans and processes to assure that we continue to meet the requirement.

We regularly review and refine our compliance strategy, weighing a number of factors such as system load projections, expected fuel selection, available control equipment and anticipated performance and costs of emissions controls. Because of the increased cost for Furnace Sorbent Injection (FSI) technology, continuing development of dry scrubber technology, changes in the fuel markets, long-term impact of (Clean Air Interstate Rule) requirements and continuing evolution of our resource plans (including the impact of Senate Bill 3), we are studying the compliance options for Cape Fear 5 and 6 to determine whether FSI still represents the most cost-effective long-term compliance option. This study, to be completed later this year, will reflect the results of the Robinson FSI testing and the latest available information regarding FSI and dry scrubber costs and performance. At this time, we are maintaining an option for either FSI or dry scrubber technology for Cape Fear 5 and 6, whichever our studies indicate to be most cost-effective.

Progress Energy Service Company, LLC
PO Box 1551
Raleigh NC 27602

We appreciate the excellent work of the Department staff, particularly those in the Air Quality and Water Quality divisions, who support our efforts to complete the projects in a timely manner to assure compliance with the Act's requirements. We look forward to continuing our positive working relationship to facilitate fulfillment of the Company's obligations with this important law.

Please don't hesitate to contact me at (919) 546-3775 if you have any questions.

Sincerely,

Caroline Choi

Caroline Choi
Director, Energy Policy and Strategy

c: North Carolina Utilities Commission
Keith Overcash, DAQ

Progress Energy Carolinas, Inc. (PEC)
North Carolina Clean Smokestacks Act
Calendar Year 2007 Progress Report

On June 20, 2002, North Carolina Senate Bill 1078, also known as the "Clean Smokestacks Act," was signed into effect. This law requires significant reductions in the emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) from utility owned coal-fired power plants located in North Carolina. Section 9(i), which is now incorporated as Section 62-133.6(i) of the North Carolina General Statutes, requires that an annual progress report regarding compliance with the Clean Smokestacks Act be submitted on or before April 1 of each year. The report must contain the following elements, taken verbatim from the statute:

1. A detailed report on the investor-owned public utility's plans for meeting the emissions limitations set out in G.S. 143-215.107D.
2. The actual environmental compliance costs incurred by the investor-owned public utility in the previous calendar year, including a description of the construction undertaken and completed that year.
3. The amount of the investor-owned public utility's environmental compliance costs amortized in the previous calendar year.
4. An estimate of the investor-owned public utility's environmental compliance costs and the basis for any revisions of those estimates when compared to the estimates submitted during the previous year.
5. A description of all permits required in order to comply with the provisions of G.S. 143-215.107D for which the investor-owned public utility has applied and the status of those permits or permit applications.
6. A description of the construction related to compliance with the provisions of G.S. 143-215.107D that is anticipated during the following year.
7. A description of the applications for permits required in order to comply with the provisions of G.S. 143-215.107D that are anticipated during the following year.
8. The results of equipment testing related to compliance with G.S. 143-215.107D.
9. The number of tons of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emitted during the previous calendar year from the coal-fired generating units that are subject to the emissions limitations set out in G.S. 143-215.107D.
10. The emissions allowances described in G.S. 143-215.107D(i) that are acquired by the investor-owned public utility that result from compliance with the emissions limitations set out in G.S. 143-215.107D.
11. Any other information requested by the Commission or the Department of Environment and Natural Resources.

Information responsive to each of these report elements follows. The responses are given by item number in the order in which they are presented above.

1. A detailed report on the investor-owned public utility's plans for meeting the emissions limitations set out in G.S. 143-215.107D.

Under G.S. § 143-215.107D(f), "each investor-owned public utility…may determine how it will achieve the collective emissions limitations imposed by this section." PEC originally submitted its compliance plan on July 29, 2002. Appendix A contains an updated version of this plan, effective April 1, 2008. We continue to evaluate various design, technology and generation options that could affect our future compliance plans.

2. The actual environmental compliance costs incurred by the investor-owned public utility in the previous calendar year, including a description of the construction undertaken and completed that year.

In 2007, Progress Energy Carolinas, Inc. incurred actual capital costs of $330,124,000.

<u>Asheville</u>

Construction was completed, and Asheville Unit 1 SCR was successfully placed in service in May 2007. This completed the Clean Smokestacks Act work planned for the Asheville plant.

<u>Lee</u>

For Unit 3, we completed tuning of the Rotamix equipment for NOx emissions control and placed the system in service in March 2007. This completed the Clean Smokestacks Act work planned for the Lee plant.

<u>Mayo</u>

In 2007, we executed contracts for the wastewater treatment bioreactor equipment and engineering, and initiated work on the wastewater treatment systems. With respect to wet scrubber scope of work, engineering, procurement and construction activities continued throughout 2007. Major milestones include: completed construction of the chimney shell; initiated installation of the absorber tower internals; received onsite a majority of absorber recycle pump, oxidation air blower, ID Fan and ball mill pieces/parts; and obtained authorization to construct the wastewater treatment facility. At year end, the Mayo scrubber project was 41% complete.

<u>Roxboro</u>

Construction work on the scrubber project continued for all four units in 2007. Specific project activities include the following:

Common
In the common area, construction of the limestone handling and preparation, gypsum dewatering and handling, oxidation air system, make-up and service water system, and

major piping was completed and commissioned in support of Unit 2 scrubber startup in April. Work was also started on installation of the limestone silo. Limestone conveyors and stack-out conveyors were completed as well.

Unit 1
Significant construction included completion of foundations for the booster fan and duct supports. Fabrication of the duct was also completed. Erection of the absorber shell was completed in October, and assembly of the absorber internals began. Erection of the pump-house and electrical building structural steel started in September 2007 and is planned to be completed in the first quarter of 2008. We also started installation of the recycle pumps, bleed pumps, and booster fans.

Unit 2
Significant milestones for 2007 include completion of the duct tie-in outage in April and the successful startup of the Unit 2 scrubber on April 24, 2007.

Unit 3
Significant construction included completion of the duct support and booster fan foundations, installation of the booster fans, and installation of duct support steel and duct work. The absorber erection was completed as well as installation of absorber internals and absorber hood/elbow. Commissioning began checkout of several systems in preparation for the April 2008 tie-in outage and scrubber startup.

Unit 4
The significant milestone was completion of the duct tie-in outage in December and the successful startup of the Unit 4 scrubber on December 1, 2007.

Wastewater Project
Significant construction activities included completion of the wastewater blow-down line, settling and flush ponds. Construction of the bio-reactor facility was started and completed in 2007. Commissioning activities started in December with the first two trains planned to be operational in early 2008. The remaining two trains are planned for commissioning later in the second quarter of 2008.

3. The amount of the investor-owned public utility's environmental compliance costs amortized in the previous calendar year.

Progress Energy Carolinas, Inc. amortized $33,881,190 in 2007.

4. An estimate of the investor-owned public utility's environmental compliance costs and the basis for any revisions of those estimates when compared to the estimates submitted during the previous year.

Appendix B contains the capital costs incurred toward compliance with G.S. § 143-215.107D through 2007 and the projected costs for future years through 2013. The costs shown are the net costs to PEC, excluding the portion for which the Power Agency is responsible. The estimated total capital costs, including escalation, are currently projected to be between $1.5 and $1.6 billion, with the current point estimate being $1.546 billion. This represents an increase from the 2007 cost estimate of $1.355 billion. Prior reports have discussed the cost impact of project scope changes and the impact of significant increases in the cost of materials and labor which have impacted construction projects across the Southeast. The current estimates continue to reflect those impacts as well as the impact of additional planning, especially with respect to the emission controls for Sutton Unit 3 and Cape Fear Units 5 and 6.

The current estimate for a dry scrubber at Sutton 3, while still conceptual, reflects the impact of more definitive site characteristics on the overall cost of the project. Space is at a premium at this site, the coastal location requires more stringent wind loading criteria, and the soil characteristics are quite different from what we have at our other plants where we have installed scrubbers. As these criteria are reflected in the conceptual design, we are seeing quantity increases (structural steel, concrete, and piping) due to the need for stronger foundations, increased structural steel, longer duct runs and other utilities than previously envisioned. To the extent that these increases can be quantified based on the limited engineering completed to date, the costs have been reflected in the current estimate.

In our last filing we noted that Furnace Sorbent Injection (FSI) technology offered a potentially more cost effective compliance option for our Cape Fear Units 5 and 6 and discussed our plans to test that technology at our Robinson Unit 1. Installation of the test unit at Robinson is nearing completion and the testing should begin this summer with operating results available by the end of the year. The engineering knowledge we have gained to date from the installation of the FSI test system at Robinson is being reflected in updated cost estimates for the installation of FSI technology at Cape Fear. One significant unknown regarding the use of this technology at Cape Fear is whether the precipitator will have to be replaced in order to maintain compliance with existing particulate emission limits. A final determination will require further engineering analysis and the benefit of test results from the Robinson demonstration. At this time, the estimate for Cape Fear Units 5 and 6 includes an allowance for replacement of the precipitator.

Because of the increased cost for FSI technology, continuing development of dry scrubber technology, changes in the fuel markets, the long term impact of the CAIR requirements, and continuing evolution of our resource plans (including the impact of Senate Bill 3), PEC has initiated a study to revisit the compliance options for Cape Fear 5 and 6. This study, to be completed later this year, will reflect the results of the Robinson FSI testing and the latest available information regarding FSI and dry scrubber costs and performance. At this time, we are maintaining an option for either FSI or dry scrubber technology, whichever our studies indicate to be most cost-effective.

5. A description of all permits required in order to comply with the provisions of G.S. 143-215.107D for which the investor-owned public utility has applied and the status of those permits or permit applications.

Progress Energy applied for the following permits in 2007:

Roxboro Plant

Air Permit

An update to the air permit for coal handling and limestone equipment was submitted on November 14, 2006. This request was approved on March 15, 2007.

A Notice for Intent to Construct for a diesel-fired emergency fire water pump was approved on February 8, 2007 and Air Quality Permit revision No. 01001T39 was issued on April 5, 2007.

Agency approval was received August 22, 2007 for our request for Alternative Method of Reporting of Annual Average Opacity for units equipped with Flue Gas Desulfurization.

A Renewal Title V Air Permit application was submitted on November 27, 2007. This renewal application met the requirements of the Construction Permit for the Flue Gas Desulfurization (FGD) System to submit a complete Title V Air Quality Permit Application on or before 12 months after commencing operation.

Mayo Plant

NPDES

A request for authorization to construct a Flue Gas Desulfurization (FGD) Wastewater Treatment System, submitted May 4, 2007, was approved and issued on November 28, 2007.

NPDES Permit modification approving our request for a mixing zone for chlorides was issued on December 14, 2007.

Erosion and Sediment Control Plan

Revision G. to the Erosion and Sediment Control Plan for the increase in disturbed land (from 35 acres to 98 acres) for the flue gas desulfurization system was submitted January 29, 2007 and was approved on April 12, 2007.

Lee Plant

Air Permit

A Title V Air Permit application was submitted on April 19, 2007 in accordance with permit requirements associated with the Low NOx Burner installation. This application was required by the Construction Permit to be submitted within 12 months after commencing operation of the low-NOx Burner.

NPDES

The NPDES Permit revision for the Rotamix Urea Injection System on Unit 3 was issued on March 23, 2007.

6. A description of the construction related to compliance with the provisions of G.S. 143-215.107D that is anticipated during the following year.

Mayo

During 2008, construction activities will focus on completion of the chimney lining and installation of absorber internals. Concurrently, placement of ID fan foundations, placement of the wastewater treatment bioreactor cells, erection of structural steel, fabrication of field erected tanks, and installation of electrical and I&C will be completed. Engineering activities will continue, with the focus shifting to the wastewater treatment related scope of work. Starting in the summer, commissioning activities will intensify in preparation for the spring 2009 plant outage and subsequent mechanical completion and placement in service of the wet scrubber and wastewater treatment systems.

Roxboro

Common
For 2008, significant construction activities planned in the common area include completion of the railroad track installation, and final site grading and paving. Specific unit activities are described below:

Unit 1
Significant construction activities planned include completion of Unit 1 absorber internals, installation of the absorber hood/elbow, completion of the pump-house and electrical building, and installation of the booster fans and duct work. Commissioning is planning to start activities in June in preparation for the October tie-in outage.

Unit 3
Significant construction activities planned include completing electrical power and control cabling and the balance of commissioning activities in preparation for the April tie-in outage.

Unit 4
In service. Major activities include issue of as-built drawings, evaluation of performance, and conducting performance tests as needed.

Wastewater
Significant construction activities planned for the bio-reactor include completing

commissioning activities for the first two bio-reactor trains with a continuation of commissioning activities on the remaining two bio-reactor trains in the 2nd quarter.

7. A description of the applications for permits required in order to comply with the provisions of G.S. 143-215.107D that are anticipated during the following year.

General

We appreciate the collaborative efforts the DAQ and DWQ staffs have made to assure our construction and installation schedules remain on track. However, the potential for longer permit processing times continue to be a serious concern for future projects. PEC will work collaboratively with the agency staff to prevent any delays from occurring.

The following permit applications and permit approvals are anticipated for 2008:

Roxboro Plant

Erosion and Sedimentation Control Plan

Plan revisions may be necessary as construction plans are further developed.

Mayo Plant

NPDES Permit

A request for authorization to construct a new oil/water separator was submitted on March 7, 2008 with a response expected by the end of April.

Erosion and Sedimentation Control Plan

Plan revisions may be necessary as construction plans are further developed.

Sutton Plant

Air Permit

An application for construction of a Dry Scrubber for Unit 3 is expected to be submitted during the fourth quarter 2008 with response expected in the second quarter 2009.

8. The results of equipment testing related to compliance with G.S. 143-215.107D.

Performance testing of the SCR at Asheville Unit 1 was completed in October 2007. The testing indicated that the system met its performance guaranteed emissions rate of 0.04 lb NO_x/MMBtu.

Performance testing of the SNCR system at Lee Unit 3 was completed in March 2007. The testing demonstrated that the system met its performance guarantee of a 31% reduction in NO_x emissions over the load range of the unit.

Performance testing of the Scrubber at Roxboro Unit 2 was completed in September 2007. The testing confirmed that the scrubber achieved its performance guarantee of 97% SO_2 removal efficiency.

9. The number of tons of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emitted during the previous calendar year from the coal-fired generating units that are subject to the emissions limitations set out in G.S. 143-215.107D.

The affected coal-fired PEC units have achieved a 59% reduction in NOx and a 25% reduction in SO_2 since 2002. The total calendar year 2007 emissions from the affected coal-fired Progress Energy Carolinas units are:

NOx 24,383 tons
SO_2 147,242 tons

10. The emissions allowances described in G.S. 143-215.107D(i) that are acquired by the investor-owned public utility that result from compliance with the emissions limitations set out in G.S. 143-215.107D.

During 2007, PEC did not acquire any allowances as a result of compliance with the emission limitations set out in N.C. General Statute 143-215.107D.

11. Any other information requested by the Commission or the Department of Environment and Natural Resources.

There have been no additional requests for information from the North Carolina Utilities Commission or the Department of Environment and Natural Resources since the last report.

Appendix A

Progress Energy Carolinas, Inc's (PEC) Air Quality Improvement Plan Supplement

April 1, 2008

On June 20, 2002, Governor Easley signed into law SB1078, which caps emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) from utility owned coal-fired power plants located in North Carolina. Under the law, G.S. § 143-215.107D, PEC's annual NOx emissions must not exceed 25,000 tons beginning in 2007 and annual SO_2 emissions must not exceed 100,000 tons beginning in 2009 and 50,000 tons beginning in 2013. These caps represent a 56% reduction in NOx emissions from 2001 levels and a 74% reduction in SO_2 emissions from 2001 levels for PEC.

PEC owns and operates 18 coal-fired units at seven plants in North Carolina. The locations of these plants are shown on Attachment 1. Under G.S. § 143-215.107D(f), "each investor-owned public utility...may determine how it will achieve the collective emissions limitations imposed by this section."

<u>Nitrogen Oxides Emissions Control Plan</u>

PEC has been evaluating and installing NOx emissions controls on its coal-fired power plants since 1995 in order to comply with Title IV of the Clean Air Act and the NOx SIP Call rule adopted by the Environmental Management Commission (EMC). Substantial NOx emissions reductions have been achieved (24,383 tons of NOx in 2007 compared with 112,000 tons in 1997), and compliance with the Clean Smokestacks Act's 25,000 ton cap was achieved in calendar year 2007. This target was achieved with a mix of combustion controls (which minimize the formation of NOx), such as low-NOx burners and over-fire air technologies, and post-combustion controls (which reduce NOx produced during the combustion of fossil fuel to molecular nitrogen), such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies.

Attachment 2 details PEC's North Carolina coal-fired electric generating units, their name plate generation capacity, and installed NOx control technologies.

<u>Sulfur Dioxide Emissions Control Plan</u>

PEC is installing wet flue gas desulfurization systems (FGD or "scrubbers") to remove 97% of the SO_2 from the flue gas at its Asheville, Roxboro and Mayo boilers. PEC is continuing its evaluation of the potential to use Furnace Sorbent Injection (FSI) technology at our Cape Fear Plant. Use of the FSI technology eliminates the need for a costly wastewater treatment system. We plan to test the FSI technology at PEC's Robinson Unit 1 beginning in summer 2008. Since Robinson Unit 1 is similar in design to the Cape Fear units, the Robinson test will indicate whether the use of this technology will be effective at Cape Fear. While PEC continues to evaluate the use of FSI at Cape

Fear, because of expected increased cost for Furnace Sorbent Injection (FSI) technology, continuing development of dry scrubber technology, changes in the fuel markets, the long term impact of the CAIR requirements and continuing evolution of our resource plans (including the impact of Senate Bill 3), we are re-evaluating all compliance options for Cape Fear 5 and 6.

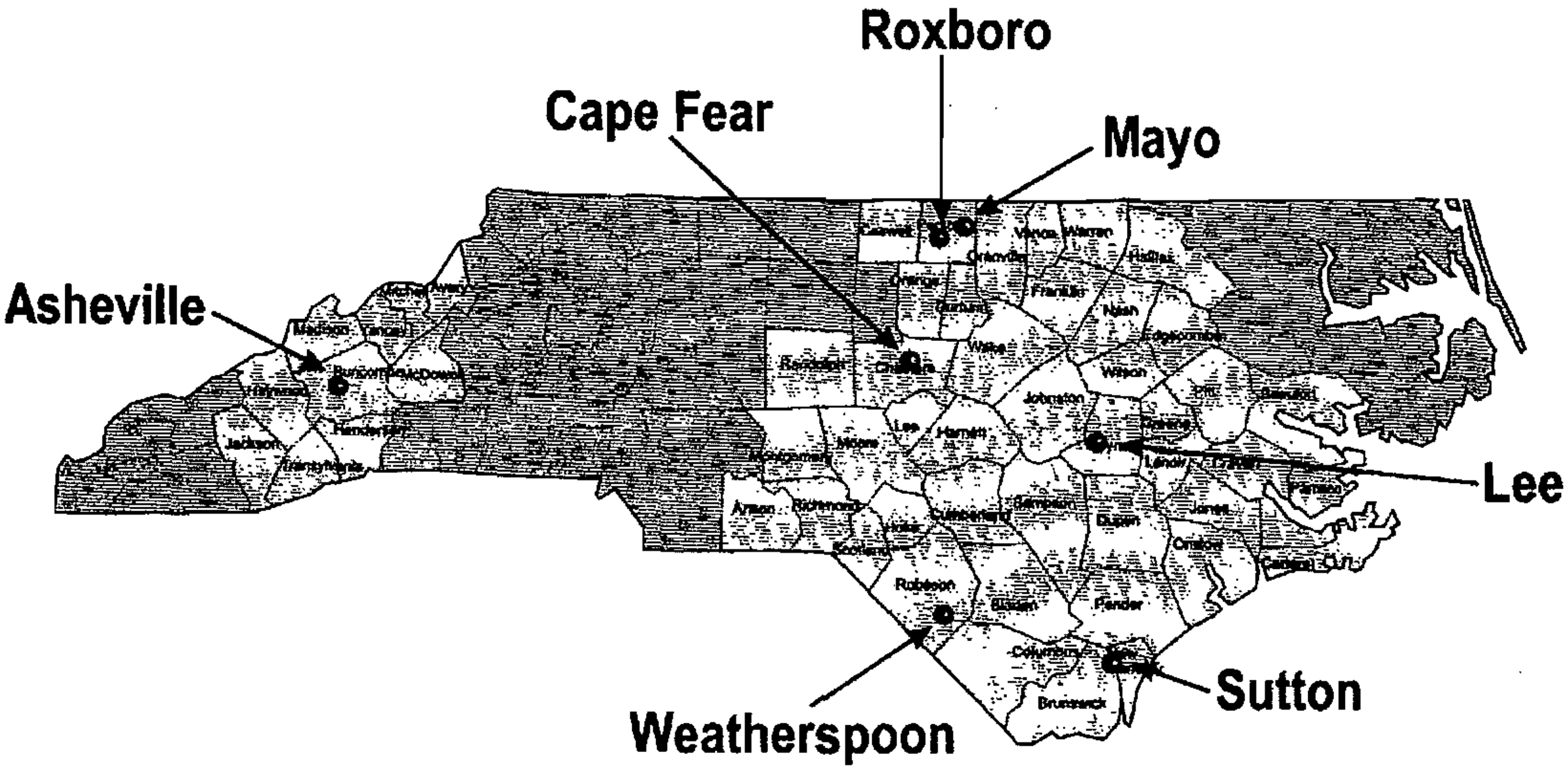
The current compliance plan also contemplates the use of a dry scrubber at Sutton Unit 3. A dry scrubber at that unit represents a more cost-effective compliance solution and also eliminates the need for a costly wastewater treatment system.

Wet scrubbers produce unique waste and byproduct streams. Issues related to wastewater permitting and solid waste disposal are being addressed for each site. PEC is treating the scrubber wastewater stream at the Asheville Plant using an innovative constructed wetlands treatment system to ensure compliance with discharge limits. A bioreactor technology will be used for the Roxboro and Mayo Plants

A contract has been executed with a gypsum product end-user that will construct a facility near the Roxboro Plant to use the synthetic gypsum produced by the Roxboro and Mayo Plants for the manufacture of drywall products. PEC also has entered into an agreement that enables PEC to market and sell synthetic gypsum produced at the Asheville Plant.

Attachment 3 details PEC's North Carolina coal-fired electric generating units, their summer net generation capability, installed SO_2 control technologies and those planned for installation. As technologies evolve or other circumstances change, a different mix of controls may be selected. Attachment 3 also projects annual SO_2 emissions on a unit-by-unit basis based on the energy demand forecast and expected efficiencies of the SO_2 emissions controls employed. These projections are based on the planned removal technologies and PEC's current fuel and operating forecasts. This information is provided only to show how compliance may be achieved and is not intended in any way to suggest unit-specific emission limits. Actual emissions for each unit may be substantially different.

Attachment 1: Location of PEC's Coal-Fired Power Plants in North Carolina



Attachment 2: PEC's 2008 NOx Control Plan for North Carolina Coal-fired Units

Unit	MW Rating	Control Technology	Operation Date[1]
Asheville 1	191	LNB/AEFLGR/**SCR**	2007
Asheville 2	185	LNB/OFA/SCR	
Cape Fear 5	144	ROFA/ROTAMIX	
Cape Fear 6	172	ROFA/ROTAMIX	
Lee 1	74	WIR	
Lee 2	77	**LNB**	2006
Lee 3	248	LNB/**ROTAMIX**	2007
Mayo 1	742	LNB/OFA/SCR	
Roxboro 1	369	LNB/OFA/SCR	
Roxboro 2	671	TFS2000/SCR	
Roxboro 3	705	LNB/OFA/SCR	
Roxboro 4	698	LNB/OFA/SCR	
Sutton 1	93	SAS	
Sutton 2	102	**LNB**	2006
Sutton 3	403	LNB/ROFA/ROTAMIX	
Weatherspoon 1	48		
Weatherspoon 2	49		
Weatherspoon 3	76	WIR	
Total	5,047		

AEFLGR – Amine-Enhanced Flue Lean Gas Reburn
LNB = Low NOx Burner
SNCR = Selective Non-Catalytic Reduction
OFA = Overfire Air
ROFA = Rotating Opposed-fired Air
ROTAMIX = Injection of urea to further reduce NOx
WIR = Underfire Air
TFS2000 = Combination Low-NOx Burner/Overfire Air
SAS = Separated Air Staging

[1] This is the operation date for the control technology installed to comply with the North Carolina Improve Air Quality/Electric Utilities Act only (shown in bold).

Attachment 3: PEC's 2008 SO_2 Control Plan for North Carolina Coal-Fired Units

Unit	MW Rating	Technology	Operation Date	Projected SO_2 Tons, 2009[1]	Projected SO_2 Tons, 2013
Asheville 1	191	Scrubber	2005	296	333
Asheville 2	185	Scrubber	2006	280	352
Cape Fear 5	144	FSI	2011	6,791	3,634
Cape Fear 6	172	FSI	2012	8,274	4,330
Lee 1	74			2,947	2,902
Lee 2	77			2,694	2,671
Lee 3	248			9,906	9,265
Mayo 1	742	Scrubber	2009	7,183	1,602
Roxboro 1	369	Scrubber	2008	685	942
Roxboro 2	671	Scrubber	2007	1,048	1,235
Roxboro 3	705	Scrubber	2008	1,046	1,493
Roxboro 4	698	Scrubber	2007	976	1,394
Sutton 1	93			4,534	3,851
Sutton 2	102			5,381	4,429
Sutton 3	403	Scrubber	2012	19,614	884
Weatherspoon 1	48			1,628	1,138
Weatherspoon 2	49			1,583	1,214
Weatherspoon 3	76			2,997	2,792
Total	5,047			77,863	44,461

FSI = Furnace Sorbent Injection

[1] Unit by unit emissions are illustrative only and specific emissions limits should not be inferred. Actual emissions in 2009 and 2013 may be different from unit to unit.

Appendix B
PEC's Actual Costs Through 2007 and Projected Costs Through 2013 for Clean Smokestacks Act Compliance (in thousands)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Asheville 1 FGD	$ 100	$ 9,652	$ 33,574	$ 35,769	$ 3,930	-$ 1,850	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 81,175
Asheville 1 SCR	$ 0	$ 0	$ 688	$ 1,423	$ 14,608	$ 11,942	-$ 262	$ 0	$ 0	$ 0	$ 0	$ 0	$ 28,400
Asheville 2 FGD	$ 100	$ 7,742	$ 28,390	$ 24,238	$ 11,701	-$ 1,543	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 70,629
Asheville FGD Common	$ 467	$ 0	$ 0	$ 0	$ 0	-$ 479	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	-$ 12
Mayo 1 FGD	$ 187	$ 0	$ 276	$ 644	$ 22,794	$104,886	$ 70,996	$ 34,623	$ 0	$ 0	$ 0	$ 0	$ 234,405
Roxboro FGD Common	$ 419	$ 5,560	$ 10,030	$ 51,717	$ 72,934	$ 36,491	$ 11,893	$ 2,208	$ 0	$ 0	$ 0	$ 0	$ 191,252
Roxboro 1 FGD	$ 0	$ 0	$ 0	$ 3,135	$ 12,164	$ 32,841	$ 42,475	$ 3,791	$ 0	$ 0	$ 0	$ 0	$ 94,406
Roxboro 2 FGD	$ 120	$ 3,574	$ 6,848	$ 30,782	$ 46,014	$ 18,975	$ 573	$ 0	$ 0	$ 0	$ 0	$ 0	$ 106,885
Roxboro 3 FGD	$ 0	$ 0	$ 244	$ 10,628	$ 36,661	$ 49,985	$ 13,555	$ 1,275	$ 0	$ 0	$ 0	$ 0	$ 112,349
Roxboro 4 FGD	$ 0	$ 0	$ 0	$ 9,075	$ 28,550	$ 57,610	$ 2,704	$ 916	$ 0	$ 0	$ 0	$ 0	$ 98,854
Cape Fear 5 ESI	$ 0	$ 0	$ 0	$ 0	$ 88	$ 0	$ 0	$ 7,752	$ 42,383	$ 11,914	$ 0	$ 0	$ 62,137
Cape Fear 6 ESI	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 39,636	$ 27,191	$ 0	$ 66,828
Lee 3 Rotamix	$ 0	$ 0	$ 0	$ 198	$ 6,424	$ 600	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,222
Sutton 3 FGD	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 760	$ 49,926	$ 152,772	$ 111,683	$ 958	$ 316,100
Lee 2 LNB	$ 0	$ 0	$ 133	$ 273	$ 1,886	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,292
Sutton 2 LNB	$ 0	$ 0	$ 0	$ 236	$ 1,900	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,136
Total without Wastewater	**$ 1,393**	**$ 26,528**	**$ 80,184**	**$ 168,118**	**$ 259,654**	**$ 309,456**	**$ 141,934**	**$ 51,324**	**$ 92,309**	**$ 204,323**	**$ 138,875**	**$ 958**	**$ 1,475,056**
Asheville WWT	$ 0	$ 0	$ 0	$ 12,365	$ 1,289	-$ 306	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 13,348
Mayo WWT	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,042	$ 15,059	$ 3,120	$ 0	$ 0	$ 0	$ 0	$ 22,221
Roxboro WWT	$ 0	$ 0	$ 0	$ 791	$ 11,965	$ 16,932	$ 5,203	$ 142	$ 0	$ 0	$ 0	$ 0	$ 35,033
Sutton WWT	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Total Wastewater Treatment	**$ 0**	**$ 0**	**$ 0**	**$ 13,156**	**$ 13,253**	**$ 20,668**	**$ 20,262**	**$ 3,263**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 70,601**
Total NC Clean Smokestacks Act	**$ 1,377**	**$ 26,528**	**$ 80,187**	**$ 181,274**	**$ 272,819**	**$ 330,124**	**$ 162,196**	**$ 54,587**	**$ 92,309**	**$ 204,323**	**$ 138,875**	**$ 958**	**$ 1,545,657**
Estimated AFUDC							$ 7,029	$ 3,877	$ 4,571	$ 18,214	$ 27,760	$ 0	**$ 60,919**

Notes: Costs reflect the Power Agency contribution. Historic year costs are actual, current year costs are projected, and future year costs are escalated.

SO2 Controls Design and Construction

SO2 Controls In-service

NOx Controls Design and Construction

NOx Controls In-service

Appendix C
PEC's Clean Smokestacks Act Compliance Plan

	Plant Project	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
General													
Asheville 1 FGD	Asheville 1 FGD												
Asheville 1 SCR	Asheville 1 SCR												
Asheville 2 FGD	Asheville 2 FGD												
Mayo 1 FGD	Mayo 1 FGD												
Roxboro 1 FGD	Roxboro 1 FGD												
Roxboro 2 FGD	Roxboro 2 FGD												
Roxboro 3 FGD	Roxboro 3 FGD												
Roxboro 4 FGD	Roxboro 4 FGD												
Cape Fear 5 FSI	Cape Fear 5 FSI												
Cape Fear 6 FSI	Cape Fear 6 FSI												
Lee 3 Rotamix	Lee 3 Rotamix												
Sutton 3 FGD	Sutton 3 FGD												
Lee 2 LNB	Lee 2 LNB												
Sutton 2 LNB	Sutton 2 LNB												

SO2 Controls Design and Construction
SO2 Controls In-service
NOx Controls Design and Construction
NOx Controls In-service

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

NOW, BEFORE ME, the undersigned, personally came and appeared, Paula Sims, who first duly sworn by me, did depose and say:

That she is Paula Sims, Senior Vice President-Power Operations of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; she has the authority to verify the foregoing Progress Energy Carolinas, Inc. North Carolina Clean Smokestacks Act Calendar Year 2007 Progress Report; that she has read said Report and knows the contents thereof; are true and correct to the best of her knowledge and beliefs.

Paula Sims
Senior Vice President-Power Operations
Progress Energy Carolinas, Inc.

Subscribed and sworn to me
this 25th day of March, 2008.

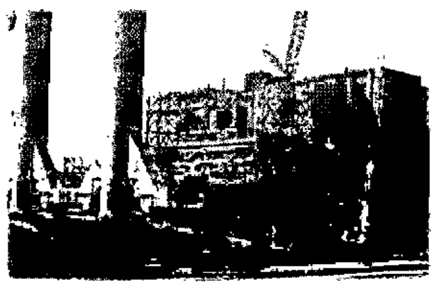
Betty Jean Young
Notary Public
My Commission Expires: October 5, 2008

BETTY JEAN YOUNG
WAKE COUNTY, N.C.

246373

SCR = Supremely Complex Retrofit

Take one giant Manitowoc crane used in the recovery efforts at the World Trade Center, 12,000-plus tons of structural steel, 2,000 cubic yards of concrete, 800-plus workers, and twin 1120 MW net supercritical boiler units, and what have you got? An engineer's playground, for sure, but also one of the largest selective catalytic reduction (SCR) projects in the U.S., at Duke Energy's Belews Creek Station in north-central North Carolina.



Click here to enlarge image

Duke Energy is installing SCR systems for NOx control at its two-unit Belews Creek power station in north-central North Carolina. The units, which will reduce NOx emissions from 0.50 lb/MMBtu to 0.10 lb/MMBtu, are scheduled to come on-line in 2003 and 2004. Photo courtesy of Duke Energy.

The $325 million Belews Creek project is a shining example of the challenges inherent to many of the large-scale SCR retrofits currently underway around the country. Tucked on a spit of land adjacent to Belews Lake, Duke Energy and its project partners - Duke/Fluor Daniel and Babcock Borsig Power - have had to fit the proverbial square peg in a round hole, adapting system design to space constraints and integrating construction activities with operational and maintenance priorities.

Despite their critical importance to NOx compliance strategies, SCR installations are primarily structural and civil projects, with a splash of process work thrown in. As the Duke workers joke at Belews, the SCR reactor is really just a "wide spot in the duct." The structural and civil challenges, however, are prodigious. At Belews Creek, for example, the SCR structure will extend above the boiler building, more than 280 feet above ground level. A key design consideration, therefore, concerned wind loads. The SCR framework had to be able to accommodate high wind loads, up to and including hurricane-force winds.

To keep the SCR structure from experiencing up-lift or tip-over, it had to be structurally anchored to the ground and to the existing boiler building, according to Harold Backman, Duke Energy Generation Services' Project Director. At ground level, rock anchors - using anchor bolts 14 feet long and 4 inches in diameter - tie the SCR addition to Mother Earth. At plant level, horizontal steel beams mate the new SCR facility to the existing boiler structure, and vertical booster columns have been built around a number of the existing steel columns to handle the additional loading from the ductwork and structure located above the existing fan room. The booster columns consist of a set of four steel members welded to the corners of the original vertical columns. A significant amount of electrical, instrumentation and plant services had to be relocated during on-line operation to facilitate these tie-ins - a significant, but not unusual, occurrence in complex SCR retrofit projects.

Some of the other unique challenges associated with the Belews Creek retrofit include:

•Increased air demand - Supply of an additional 600 scfm dedicated air compressor to satisfy all of the extra project air requirements.

•ID/FD fan upgrades - New impellers installed in all fans to handle a gas flow of 10,272,000 lb/hr. The primary air fans will be downsized as a result of the increased capacity in the FD fans.

•Equipment staging – The staging yard is located about one mile from the work site, demanding coordinated and timely movement of parts and supplies to match construction schedule.

•Air preheater design – The new vertical shaft rotary regenerative secondary air preheaters are being installed on the SCR structure beneath the SCR on both units. Outage work will require the removal of existing secondary air preheaters and associated ductwork in order to install new duct configuration.

The SCRs for Belews Creek are scheduled to come on-line in Spring 2003 (Unit 1) and Spring 2004 (Unit 2). The units are designed for a nominal 80 percent NOx reduction, from 0.50 lb/MMBtu to 0.10 lb/MMBtu, at 2 ppm slip. The SCR reactor will initially be charged with two layers of TiO_2-V_2O_5-WO_3 catalyst from Cormetech, with two spare layers available for operating flexibility. Although Belews Creek could have installed a bypass system and operated the SCRs only during the ozone season to comply with the NOx SIP Call, Duke decided that the more cost-effective option was to eliminate the bypass since year-round operation of the SCRs would be required to meet the NOx reduction provisions of the state's Clean Smokestacks legislation by 2007.

Correction:

In the October article, "Inlet Air Filtration Adapts to Evolving Gas Turbine Technology," the caption accompanying the photo on page 51 is incorrect. The correct caption should be, "Coalescer filter." Power Engineering regrets the error.

Power Engineering November, 2002
Author(s) : Steve Blankinship

Find this article at:
http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit

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COVER STORY

SPECIAL REPORT

FEATURES

On the cover
The Tennessee Valley Authority's Allen Plant represented a unique challenge for catalyst management due to its two-layer catalyst limitation and because the units were built without a selective catalytic reduction bypass. The units started with an 8.2-mm-pitch Cormetech honeycomb catalyst, but a 7-mm catalyst was also qualified during the initial design and installation. In the second year of service, after approximately 16,000 hours of operation, catalyst management options were investigated ranging from in-kind replacement to in-situ washing, external washing, and rejuvenation. The solution involved an in-situ replacement of the 8.2-mm-pitch product with an extension of the prequalified 7-mm-pitch product. The same process has been successfully carried out on all three units over the past 18 months. *Photo courtesy of Tennessee Valley Authority*

DEPARTMENTS

Estimating SCR installation costs

The EUCG surveyed 72 separate installations of selective catalytic reduction (SCR) systems at coal-fired units totaling 41 GW of capacity to identify the systems' major cost drivers. The results, summarized in this article, provide excellent first-order estimates and guidance for utilities considering installing the downstream emissions-control technology.

By Mark Marano and George Sharp, American Electric Power, and the EUCG Fossil Productivity Committee

The goal of the Clean Air Interstate Rule (CAIR) signed into law almost a year ago is to reduce NO_x emissions by 60%, relative to 2003 levels, across 28 eastern states and the District of Columbia by 2015. Though SCR systems worth more than $4 billion are expected to be purchased worldwide next year, in the U.S. more than 40 GW of capacity in CAIR-affected states are expected to be equipped with the technology by 2010.

This increased level of SCR installation activity comes on the heels of the 1995 NO_x SIP (State Implementation Plan) Call Rule, which motivated the installation of almost 85 GW of SCR installations at central station steam plants over the past decade. Many utilities will have to place orders this year to comply with the NO_x Phase I in-service deadline of 2009. Full implementation of CAIR will occur in 2015. One of the challenges facing utilities affected by CAIR and actively analyzing their cap-and-trade options is to understand the capital costs involved in retrofitting an SCR system.

Survey results

The EUCG, an association of 24 electric utilities representing 302 individual coal-fired units, is a forum through which the utilities can enhance their O&M and construction practices to improve their operational and cost performance.

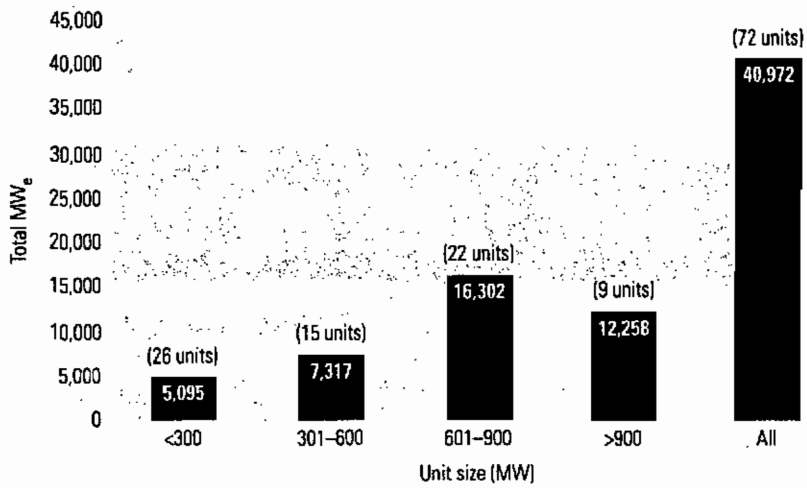
One vehicle used by the EUCG is member surveys. One recently completed survey focused on SCR system installation costs and the project and design attributes that contribute to them. Specifically, it identified the costs of construction labor; equipment; materials; and project management, engineering, and construction management (PMEC). The survey addressed 11 specific scope/design unit attributes such as the type of ammonia system used, the NO_x-removal efficiency design basis of the system, and SCR-related plant upgrades (such as economizer, air heater, and fans) on a $/kW basis.

Responses to the survey yielded scope, cost, and design information on 72 individual units totaling 41 GW (representing 39% of installed SCR systems in the U.S. by MW at the time of the study) owned by eight large utilities from SIP Call states located in the East and Midwest. The sample also reflected the distribution of installations in the U.S., so the survey results can be considered a valid top-level view of system costs.

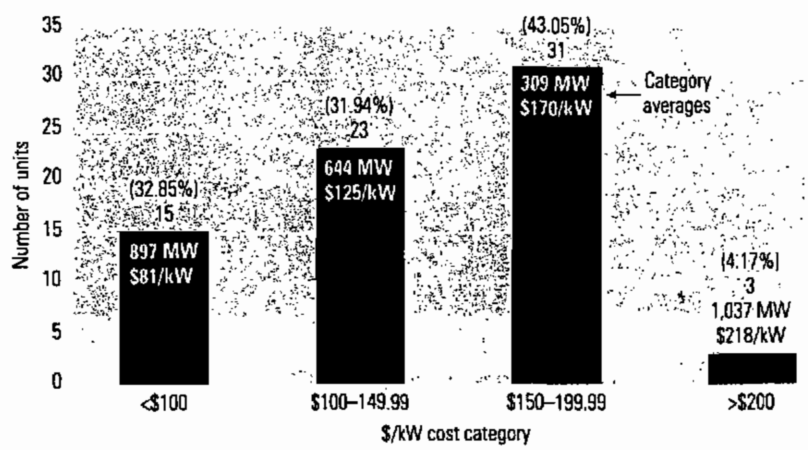
Economies of scale

As Figure 1 shows, although almost three-fourths of the surveyed units have a capacity of 300 to 900 MW, together they

1. SCR cost survey results. Survey results, categorized by plant size, covered approximately 39% of the new selective catalytic reduction (SCR) capacity installed through early 2004. *Source: EUCG Inc.*



2. What they spent. Most surveyed utilities spent between $100 and $200/kW for a selective catalytic reduction system. *Source: EUCG Inc.*



The variation in material costs was constant over the survey period, most likely reflecting increased competitiveness among SCR suppliers.

represent only a little over half of the total capacity studied. Overall, costs were reported to be in the $100 to $200/kW range for the majority of the systems (Figure 2), with only three reported installations exceeding $200/kW. System size (with a 644-MW average unit size in the $100 to $150/kW range) seems to dominate; larger average system costs are significantly less than the next survey category (the $150 to $200/kW range, with a 309-MW average unit size). The data also suggest that the larger units were installed earlier: The average unit size retrofit before 2003 was 623 MW, versus 466 MW since 2003.

The range of category costs by unit size ($/kW) provides insight into SCR projects' relative complexities. For example, the aggregated reported costs in the defined categories (Figure 3) point to several conclusions:

- The cost of construction labor on smaller projects exceeds the average construction labor cost in all categories by about 50%. The implication is that small plants will be cost-penalized by their lack of economies of scale because they may be more difficult to retrofit.
- Construction labor costs were relatively constant for plants larger than 300 MW, with an average cost of just over $64/kW.
- As expected, economies of scale also affect SCR material costs, with larger units costing less to retrofit, on a $/kW basis, than smaller units.
- Sophisticated regression modeling techniques (multivariate analysis) generally did a poor job of predicting overall installed costs; too many site-specific variables impact construction costs.
- PMEC costs are relatively consistent regardless of unit size.

The good old days

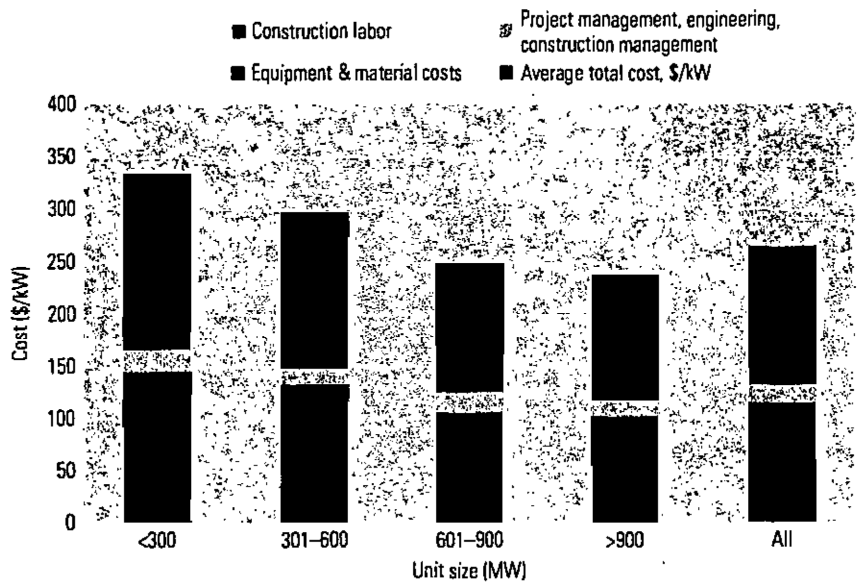
The survey data also revealed that deviations from average installation costs correlate strongly with project timing, especially for those units installed after 2003 (Figure 4). The significantly higher construction labor costs for later projects most likely reflect increased project complexity—"easier" projects were already completed—but also perhaps increased competition for skilled labor resources as the number of SCR installation projects under way in the U.S. skyrocketed.

Interestingly, the variation in material costs was constant over the survey period, most likely reflecting increased competitiveness among SCR suppliers. By contrast, PMEC costs showed higher variability, which—as in the case of construction labor costs—reflected the greater complexity of later projects. Average cost variation by cost category is summarized in the table.

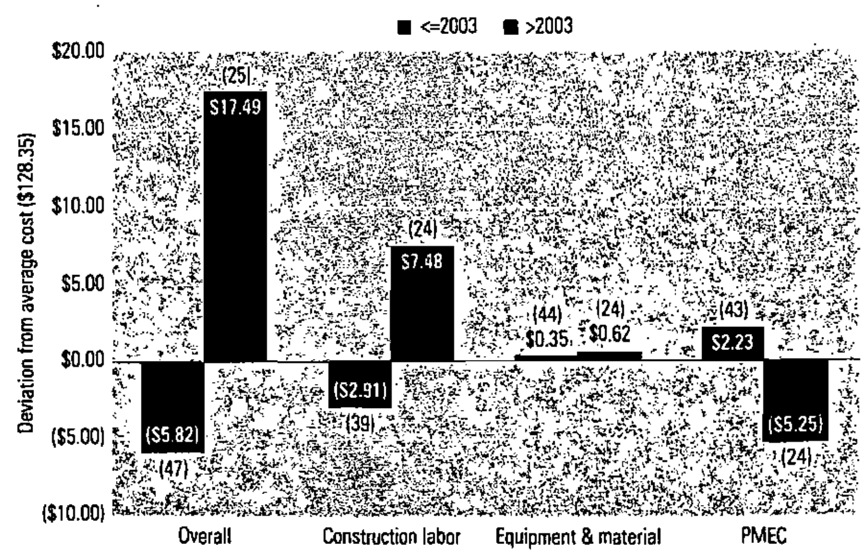
One survey, many conclusions

Although the survey results provide useful insight into expected installed costs, they

3. Cost by unit size. The cost distribution for 72 units with SCR installed shows expected economies of scale. *Source: EUCG Inc.*



4. Timing affected costs. The deviation of category costs as a function of SCR project completion date shows that early adopters paid less than those that lagged behind. *Source: EUCG Inc.*



Notes: Numbers in parentheses indicate number of collected survey datapoints for grouping.
PMEC = project management, engineering, construction management

Variation of surveyed cost categories by unit size

	Unit size (MW) <300	301–600	601–900	>900
Construction labor				
Minimum	63.27	34.65	34.64	33.22
Average	92.78	57.11	65.90	54.45
Maximum	116.85	109.65	125.59	76.96
Equipment and material costs				
Minimum	32.28	21.97	13.90	31.46
Average	52.44	75.25	38.66	47.56
Maximum	64.54	57.79	66.28	79.44
Project management, engineering, construction management (PMEC)				
Minimum	15.02	10.00	0.26	3.61
Average	21.67	15.63	19.72	16.39
Maximum	35.84	32.48	45.01	38.44
Total cost ($/kW), average	**166.89**	**147.99**	**124.28**	**118.4**
Total cost ($/kW), maximum	186.20	192.13	220.79	194.84

Source: EUCG Inc.

also confirm that there is no one-size-fits-all SCR design. What the data also make clear is that site-specific characteristics of units and plants can drive a project's cost much higher than anticipated. Together, these conclusions suggest that "retrofit difficulty" is indeed relative. Units with a capacity of 600 to 900 MW appear to be more difficult to retrofit than those in other size ranges.

Because SCRs are unitized, greater economies of scale were expected from the survey results. Some possible explanations for the modest advantage of scale include:

- The impact of newer plants' tighter layouts, which often necessitate much more complex duct installations, which raises costs).
- Plants' limited ability to use the most cost-effective method of equipment transportation. Some 41% of the units surveyed in the 600- to 900-MW range are close to navigable waters, versus 76% of units larger than 900 MW.
- The increasingly modular design of SCR systems, which reduces their capital costs but still requires them to be delivered by sea or river. ■

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SCR FOR COAL-FIRED BOILERS: A SURVEY OF RECENT UTILITY COST ESTIMATES

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Abstract

Accurate projections of SCR capital cost are critical both for prudent NOx control rulemaking by federal and local environmental regulators, and to establish realistic utility compliance plans. Within the last few years, many utilities have engaged architect/engineers and/or SCR vendors to project SCR cost for selected units in their system, employing detailed site-specific assessments. This paper reports results of SCR cost studies conducted by eleven utility companies, addressing 24 dry-bottom boilers, and 27 Group 2 boilers. The results show significant uncertainty characterizes SCR capital cost estimates, as a wide range of values is projected for both boiler types. This paper discusses and evaluates cost trends, demonstrates the impact of capital cost uncertainty on the cost per ton of NOx removed, and compares capital cost results with those from a computer algorithm widely used in NOx control rulemaking.

Introduction

The availability of selective catalytic reduction (SCR) NOx control technology at reasonable cost is a key consideration in the promulgation of NOx emission limits by federal and local environmental agencies. The cost of SCR is a topic of considerable disagreement among the various "stakeholders" participating in the NOx emissions debate - most significantly the utility industry, federal and local environmental regulatory agencies, and vendors of SCR technology. This disagreement is capital cost translates into equal uncertainty regarding projections for cost per ton of NOx reduced. Specific concerns have been summarized in written comments submitted by the utility industry (UARG, 1997) to the Environmental Protection Agency's Acid Rain Division (ARD), and in technical reports submitted by industry for use by the Ozone Transport Assessment Group (OTAG, 1996a). Rebuttal positions have been formally issued by the EPA ARD (EPA, 1996a), and OTAG stakeholders that support SCR-based NOx limits (OTAG, 1996b).

In December 1996, the EPA ARD issued NOx emissions for Group 2 boilers based on an evaluated cost per ton of NOx removed, which required EPA to project SCR capital cost for the national boiler population. In June of 1997, the OTAG Policy Committee issued general recommendations for the control of NOx emissions, which may require broad application of SCR from generating units in the 38 states that comprise OTAG's interest. Both the EPA ARD and the OTAG Policy Committee base their understanding of SCR cost on discussions with equipment suppliers, and experience from Europe. EPA ARD developed a cost algorithm to project SCR capital cost as a function of generating capacity, and used this algorithm to select the NOx levels proposed in December 1996 (EPA, 1996b), as well as support OTAG analysis.

During approximately the same time period, many utilities sponsored detailed studies by architect/engineering firms and/or SCR vendors to estimate SCR capital and operating cost. Given the significant cost implications of NOx policy decisions, it is prudent to summarize cost results derived from these utility-sponsored engineering studies, for discussion and comparison with other cost sources.

Objective

The objective of this paper is to report the range of SCR capital cost determined by site-specific engineering studies, estimated by either architect/engineering firms and/or SCR technology vendors.

Subsequently, the impact of capital cost on the cost per ton of NOx removed is calculated. The influence of two economic parameters that strongly dictate SCR cost - capacity factor and capital recovery factor - is also demonstrated.

Approach

Utilities known to have sponsored major NOx planning studies that employed detailed site assessments were requested to volunteer cost results for summary and comparison.

Given the competitive climate within the utility industry, disclosure of factors that affect the cost of generation has become extremely sensitive. With the exception of two studies entered into the public record as part of CAAA Section 407 rulemaking (OVEC, 1997, and TECO, 1996), utility companies only shared cost information on the basis that specific units remain anonymous.

This evaluation considered only engineering studies that employed a site assessment by the architect/engineer, or SCR vendor. Cost estimates were required to be developed from specific equipment lists, derived after considering plant layout, design specifications of the plant and components, and condition of existing equipment (e.g. flue gas handling components). In most cases, the studies employed a general arrangement drawing to identify the location of the reactor and ancillary equipment, as well as flue gas routing.

Eleven utility companies provided engineering studies for review that addressed SCR capital cost for selected units in their system. These utilities are located in the midwest, portions of the northeast, and the mid-Atlantic states. The data set consists of a total of 24 dry-bottom boilers (e.g. wall- and tangential-fired), and 27 Group 2 boilers (cyclone, wet-bottom, and cell-fired).

The number of boilers represented is a small fraction of the national inventory. Within the 38 state OTAG region alone, approximately 700 dry-bottom boilers exist. The total number of cyclone, wet-bottom, and cell-fired boilers nationally number approximately 140. No rigorous statistical analysis is possible with this data set, as the details of sites are unknown.

Description Of Cost Methodology

This section summarizes the cost methodology followed by most studies.

Cost Methodology

A detailed description of SCR cost methodology has been presented in an earlier paper (Cichanowicz, 1993). This discussion highlights the following cost elements that are of particular interest in this evaluation: Process Capital, Installation Charge, Process/Project Contingency, Utility Indirect Charge, and Allowance for Funds During Construction (AFDC)

Process Capital. Process Capital reflects acquisition cost for equipment required for both the SCR process, and modifications to the balance-of-plant or ancillary components. The Process Capital reflects the sum of expenditures for equipment delivered to the site, but not an installation charge.

Table 1 summarizes the major Process Capital components. The first three items (SCR catalyst, reactor, reagent storage, and reagent vaporization) are direct SCR capital requirements, with remaining items denoted as balance-of-plant components or installation expenditures. A subsequent section of this paper addresses how costs partition between these two categories.

Installation Charge. The Installation Charge reflects primarily the labor charge and lease of special equipment required for installation/erection, as well the upgrade of balance-of-plant equipment or ancillary components.

Process/Project Contingency. These cost elements comprise a "reserve" fund for unanticipated expenses due to either project-specific or process-specific issues. Most of the engineering studies used 15-20% (of Process Capital and Installation Charge) for the sum of both contingency funds.

Utility Indirect Charge. Utility-incurred costs are comprised of staff engineering, project management, and facilities such as access roads, buildings, etc., and is usually 5-10% of Process Capital and Installation Charge.

Allowance for Funds During Construction (AFDC). AFDC is a finance charge, incurred for time periods when equipment is not employed in power production. Although not necessarily a significant cost component compared to the sum of all other components, AFDC represents a real incurred cost, and is included for completeness. All planning studies reviewed included a modest charge of nominally 4-5% annually, for a period of usually 1-2 years.

Most results were derived for a 1995-1997 dollar basis, and for generally similar process conditions (major exceptions are noted). These similarities, and the desire to observe only gross trends, allow the use of results as directly reported, thus not corrected for cost year basis and process conditions.

Capital Cost Components

Two cost indices are proposed to further characterize capital cost: (a) the Process Capital/Installation Charge ratio, and (b) the sum of the catalyst, reactor, and reagent storage/vaporization components to the Process Capital. These cost ratios are further described as follows:

Ratio of Process Capital/Installation. Process Capital/Installation Cost ratio, determined before application of Process/Project Contingencies, Utility Indirect Costs, and AFDC indicates whether the bulk of direct costs are driven by capital procurement (ratio >1) or manpower for installation (ratio <1).

It is anticipated a difficult retrofit site with significant obstacles that complicate access of construction equipment would be characterized by a relatively low Process Capital/Installation Cost ratio; a site with relatively unrestricted access would be characterized by Process Capital/Installation Cost ratio of >1.

Ratio of SCR Process/Process Capital. SCR Process/Process Capital ratio, determined before application of Process/Project Contingencies, Utility Indirect Costs, and AFDC indicates whether the bulk of process equipment acquisition costs are for SCR components, or balance-of-plant equipment to allow the boiler/plant to accommodate SCR process impacts.

It is anticipated that sites requiring few modifications would be characterized by a relatively high SCR Process/Process Capital ratio; retrofit sites that require boiler modifications and upgrades to accommodate the SCR process would be characterized by a relatively low SCR Process/Process Cost ratio.

Results

Results from this survey are presented according to two major boiler categories: dry bottom and Group 2 (cyclone, wet-bottom, and cell-fired). Ideally, separate cost comparisons would be developed for each of the five major boiler categories. However, the relatively small number of units and the desire to observe only general trends allows this simplification. Results are discussed according to (a) capital cost, and (b) components of capital cost.

Capital Cost

Dry-Bottom Boilers. Figure 1 summarizes SCR capital cost for dry-bottom boilers, presented as a function of generating capacity. The NOx reduction efficiency for all units is 80-90%, with residual NH3 a maximum of 5 ppm (2 ppm for selected sites). With the exception of two units, boiler initial NOx production rates are approximately equivalent to the Phase 1, Group 1 limits of 0.45-0.50 lbs/MBtu, depending on boiler type (e.g. tangential- or wall-fired). Note several of the data represent multiple units at the same station.

Group 2 Boilers. Figure 2 summarizes SCR capital cost for cyclone, wet-bottom, and cell-fired boilers, presented as a function of generating capacity. The wet-bottom boilers, all which feature SCR designed for 50% NOx removal from approximately 1.1-1.3 lbs/MBtu, are identified separate from the cyclone and cell-fired boilers. The SCR NOx reduction efficiency for the cyclone and cell-fired boilers is 80%, with one case at 50% noted. Except as indicated, all cyclone/cell-fired boiler NOx production rates are 1.2-1.5 lbs/MBtu. All costs reflect sufficient catalyst to maintain a residual NH3 level of at most 5 ppm, throughout the entire operating period.

Capital Cost Components

Figure 3 presents trends in both the Process Capital/Installation Cost and SCR Process/Process Capital cost ratios, as a function of projected capital cost, for dry-bottom boilers. As suggested, the highest capital cost sites are characterized by a Process Capital/Installation Cost ratio of 1-1.25; the lowest capital cost sites can have values exceeding 2. The SCR Process/Process Capital ratio ranges from 0.50 for high cost sites, to 0.75 for low cost sites.

Results Discussion

Results presented in this paper are based upon an extremely small sample of the boilers, compared to the candidates considered to deploy SCR NOx control. Clearly, caution should be exercised in extrapolating any results or observations in cost trends from this sample to the national or the OTAG regional population.

Average Capital Cost

Dry-Bottom Boilers. The average of capital cost for dry-bottom boilers for all 24 boilers presented in Figure 1 is $86/kW. The average for units greater than 175 MW capacity is $75/kW.

Figure 1 demonstrates the wide variation in capital cost depending on site-specific conditions. If only generating capacity is considered as an indicator of "average" SCR capital cost, significant variations from the $75/kW average for units >175 MW are witnessed. Specifically, within the cluster of units at approximately 550 and 625 MW, any unit can vary in cost by $30-50/kW.

Group 2 Boilers. The average of capital cost for Group 2 boilers for all units presented in Figure 2, calculated with four different averaging techniques, ranges from $79-86/kW. The lowest cost ($79/kW) was determined by eliminating boilers of less than 200 MW capacity, using only 2 boilers at each of the Kyger and Clifty Creek sites in the average, and eliminating balance-of-plant upgrades necessary to accommodate SCR at three large cyclones. The highest cost was determined by employing all boilers in Figure 2 in the average (all 11 Kyger and Clifty Creek units, and not eliminating small boilers), and including balance-of-plant costs for the large cyclones.

For units above 200 MW capacity, if generating capacity alone is used to project SCR capital cost, significant variations from the nominal $83/kW average are witnessed. These variations appear to be $15-50/kW.

Economies of Scale

SCR is generally recognized by most observers to exhibit economies of scale with respect to capital cost. This trend is dependent upon the assumption that all other plant and SCR process design factors are maintained equivalent, as generating capacity increases.

Figure 1 shows that cost per unit capacity decreases as generating capacity increases from 100 to 200 MW. The average SCR cost for the units at approximately 600 MW suggests continued cost reduction at larger capacities. For the Group 2 boilers, the different boiler designs prevent identifying any trend between cost and generating capacity.

For both boiler categories, the reduction in SCR unit cost with increasing generating capacity is most pronounced for increases from lowest (~100 MW) to intermediate capacities (~175-200 MW). SCR capital cost may not exhibit economies-of-scale anticipated at larger capacities, as the design basis for the SCR process and host unit changes significantly with increased capacity. An example is the utilization of two reactors (each of 50% treating capacity) in place of one reactor (at 100% capacity), to maintain turndown for larger units.

Cost Per Ton Evaluation

The cost of NOx control per ton of NOx removed - sometimes referred to as cost-effectiveness - is an important cost index. The EPA ARD has issued NOx regulations for Group 2 boilers based on the "cost-effectiveness" of low NOx burners on Group 1 boilers compared to the "cost-effectiveness" of candidate NOx control technologies on Group 2 boilers. Essentially all NOx trading programs proposed or presently in place employ this cost index. Also, several states have proposed definitions of Reasonably Available Control Technology (RACT) depending on the "cost-effectiveness" of NOx reduction achieved by any given technology. It is instructive to examine the significance of the uncertainty in capital cost observed in Figures 1 and 2 on the evaluated cost per ton of NOx removed. Also, the impact on cost-effectiveness of two economic factors of particular significance for SCR - the capital recovery factor and generation capacity factor - is addressed.

Capital Cost

Table 2 summarizes NOx control cost per ton provided by SCR, as applied to (a) dry bottom boilers in a "post-RACT" mode, and (b) Group 2 (cyclone) boilers. Table 2 also presents the sensitivity of cost per ton to uncertainties in capital cost, capacity factor (CF), and capital recovery factor (CRF).

Dry-Bottom Boilers. Cost results apply only to the specified conditions of 80% NOx reduction, initial NOx production rates of 0.45-0.50 lbs/MBtu, 4 year mean catalyst life, and a final space velocity of 3200 1/h. The generation capacity factor and annual capital recovery factor are 65% and 0.15, respectively. For the average SCR cost (as approximated from Figure 1) of $75/kW, Table 2 shows that SCR NOx control cost is $1600-1768/ton, for boiler NOx production rates of 0.50 and 0.45 lbs/MBtu, respectively.

Table 2 also shows the impact of $15/kW variations in capital cost. Increasing capital cost by $15/kW to $90/kW would increase the $1600-1768/ton cost range by $220-250/ton. Similarly, decreasing capital cost by $15/kW to $60/kW would decrease the $1600-1768/ton range by approximately the same.

Group 2 Boilers. Cost results apply only to the specified conditions of 80% NOx reduction, 4 year average catalyst life, initial NOx production rate of 1.3 lbs/MBtu, and a final space velocity of 2000 1/h.

For the average SCR cost (as approximated from Figure 1) of $79/kW, Table 2 shows that SCR NOx control cost is $696/ton, for NOx production rates of 1.3 lbs/MBtu. Adjustments to capital cost by $15/kW impact cost by $80/ton.

Sensitivity Analysis: Additional Factors

Although the focus of this paper is SCR capital cost, it is prudent to briefly consider two other factors that can dominate the evaluated cost per ton of NOx reduced by SCR. The ability to recover capital cost, as determined by unit capacity factor and financing conditions, is particularly important with SCR, due to the high capital requirement compared to alternatives. This section demonstrates how the range of capacity factor and capital recovery factor impact the evaluated cost per ton.

Capacity Factor. Future projections of capacity factor for the deregulated industry have received considerable attention recently. Projections for system capacity factor averages range from 65% to as high as 85%, depending on the economic conditions presumed for the relevant time period. This differential of 20 percentage points translates into a considerable difference in cost per ton of NOx. As shown in Table 2, simply increasing capacity factor from historical norms of 65% to 85% lowers SCR cost per ton for dry-bottom boilers by $340 to $380/ton, for boiler NOx productions rates of 0.50 and 0.45 lbs/MBtu. For Group 2 boilers, the same increase in capacity factor lowers evaluated cost by approximately $120/ton.

Capital Recovery Factor. Utility planning studies reviewed documented the range in capital recovery factor employed for cost evaluations. This factor depends not only on the details of financing capital, but also the secondary cost of equipment ownership, such as property taxes, insurance, etc. Most significantly, the term over which the utility intends to operate the facility - either 10, 15, or 20 years - exerts a dominant role in determining the capital recovery factor. The studies reviewed for this paper show the range in capital recovery factor to be 0.14- 0.167. Within the NOx policy debates, stakeholders supporting the application of SCR have proposed a capital recovery factor of 0.115, for a 20 year plant life. Accordingly, a sensitivity analysis was conducted to determine the impact of capital recovery factor to levels as low as 0.115.

Table 2 shows for dry bottom boilers reducing capital recovery factor to 0.115 lowers evaluated cost by $650/ton, for a boiler NOx production rate of 0.50 lbs/MBtu. For Group 2 boilers, the same variation in capital recovery factor lowers evaluated cost by $90/ton. Accordingly, the role of capital recovery factor is significant, and is equal to or greater than the impact of reasonable changes in capacity factor or capital cost.

Observation

Results from this evaluation highlight how uncertainty in capital cost, capacity factor, and capital recovery factor impact cost per ton of NOx.

Depending on the value of capital cost, capacity factor, and capital recovery factor, the evaluated cost per ton of NOx can vary by almost 50%. Specifically, Table 2 reports cost per ton for both dry-bottom and cyclone boilers, employing inputs that based on the studies reviewed for this paper, discussions with utilities, and economic projections, appear extreme. These values are $60/kW capital cost, 85% capacity factor, and 0.115 capital recovery factor. Employing these values for dry-bottom boilers produces a cost of $935-1029/ton, approximately 55% of that estimated for the "baseline" case. For cyclone boilers, cost is $424/ton, or 60% of the "baseline"

The cost per ton is further reduced, when employing capital cost estimates based on the computer algorithm describing capital cost versus generating capacity, that was derived by EPA ARD. For dry-bottom boilers, using 550 MW as a reference case, this correlation used in OTAG rulemaking projects a capital requirement of $47/kW, for an SCR process designed for 80% NOx removal from Phase 1/Group 1 boiler NOx production rates. A generating capacity of 650 MW is anticipated to require SCR capital cost of $44/kW, according to this correlation.

These algorithm-derived estimates are 60-65% of the average capital cost at 550 and 650 MW presented in Figure 1. Using these algorithm-derived capital costs results in estimates of cost per ton of $791-818/ton, half of the baseline case. Similar trends were noted with Group 2 boilers, where the algorithm also significantly underpredicted cost for 50% NOx reduction cases.

Summary

Engineering studies submitted by 11 utility companies revealed trends in SCR capital cost, based on detailed site-specific assessments. For dry bottom boilers, the projected cost for SCR was $86/kW, and reduced to $75/kW when boilers less than 175 MW were eliminated. For cyclone boilers, the average cost was $79-86/kW, depending on how the average was calculated.

This significant capital cost uncertainty translates into equivalent uncertainty in cost per ton. Economic and technical premises selected from this survey suggest deploying SCR delivers NOx reduction for $1600-1768/ton, in a post-LNB application. For cyclone boilers, the cost per ton anticipated for these conditions is $674/ton.

Both capacity factor and capital recovery factor exert significant impact on cost per ton. By using values for these inputs that based on the utility site-specific studies appear to be extreme, evaluated cost can be reduced to 55-62% of the previously cited values. Further complicating the matter is the apparent tendency of the SCR capital cost algorithm developed for NOx rulemaking by EPA ARD to underpredict SCR capital cost, producing estimates approximately 60-65%% of those inferred from Figure 1. In summary, estimates of SCR cost that do not employ a detailed site-specific analysis could be significantly in error, and generating capacity and capital recovery factor should be carefully considered to reflect authentic industry experience.

References

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TABLE 1

SUMMARY OF PROCESS CAPITAL COMPONENTS
FOR SCR RETROFIT

Cost Component	Comment
SCR Catalyst, Reactor	usually the largest cost components
Reagent Storage	facilities for the unloading, transfer, and storage for aqueous or anhydrous ammonia reagent
Reagent Vaporization/Injection	equipment to vaporize reagent, and monitor and control injection rate
Sootblowers	included in almost all SCR designs and cost estimates; sometimes not seperately identified
Foundations	re-inforcing of existing foundations, or construction of new foundations depending on reactor location
Structural Steel	re-inforcing of existing structures, or construction of new structures depending on reactor location
Ductwork Modifications	modifications to existing ductwork to accommodate SCR equipment
New Ductwork	new ductwork for process bypass, reactor access, etc.
Process I&C	control systems for process operation
Fan Modifications	improvements to existing fans to increase flow rate rating, or replacement with new fans
Balanced Draft Conversion	reinforcement of ductwork structure, and addition of fans as necessary to convert from forced to balanced draft.
Electrical	additional auxiliary power supply for reagent, blowers, etc. can require an increase in power delivery capabilities on-site
Boiler Modifications	installation of economizer bypass, removal or addition of heat absorbing surface area as necessary to provide correct flue gas temperature vs. load
Other (BOP)	modifications to the air heater to improve tolerance to increased SO3; improvements to particulate control equipment to tolerate residual NH3, SO3; etc.
Duct Burner, Gas/Gas Heater	heat exchange equipment necessary for post-FGD applications
Misc/General	flow modeling, construction management, demolition charge, etc.

FIGURE 1. DRY BOTTOM BOILERS: SCR CAPITAL COST VS. CAPACITY

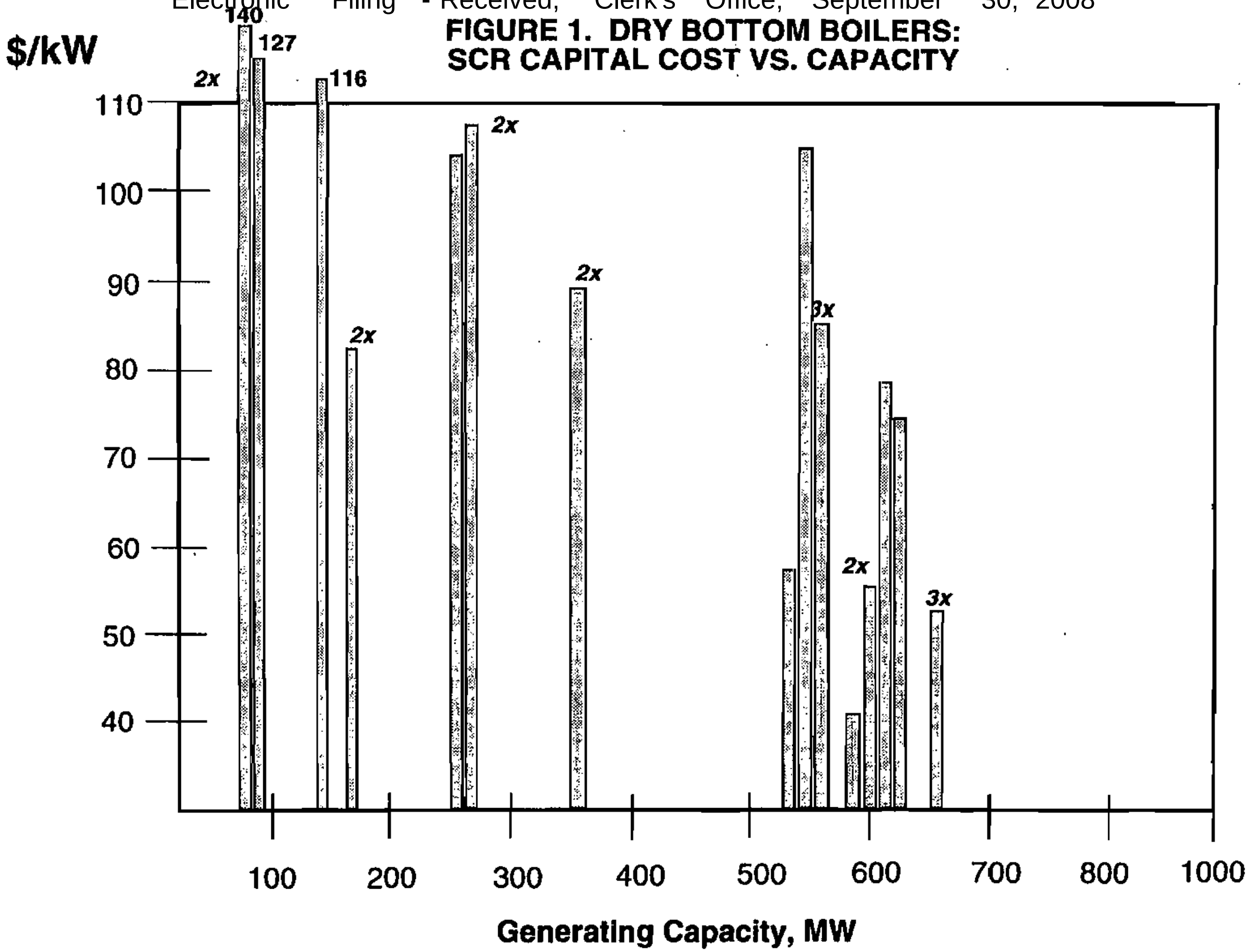

FIGURE 2. GROUP 2 BOILERS: SCR CAPITAL COST VS. CAPACITY

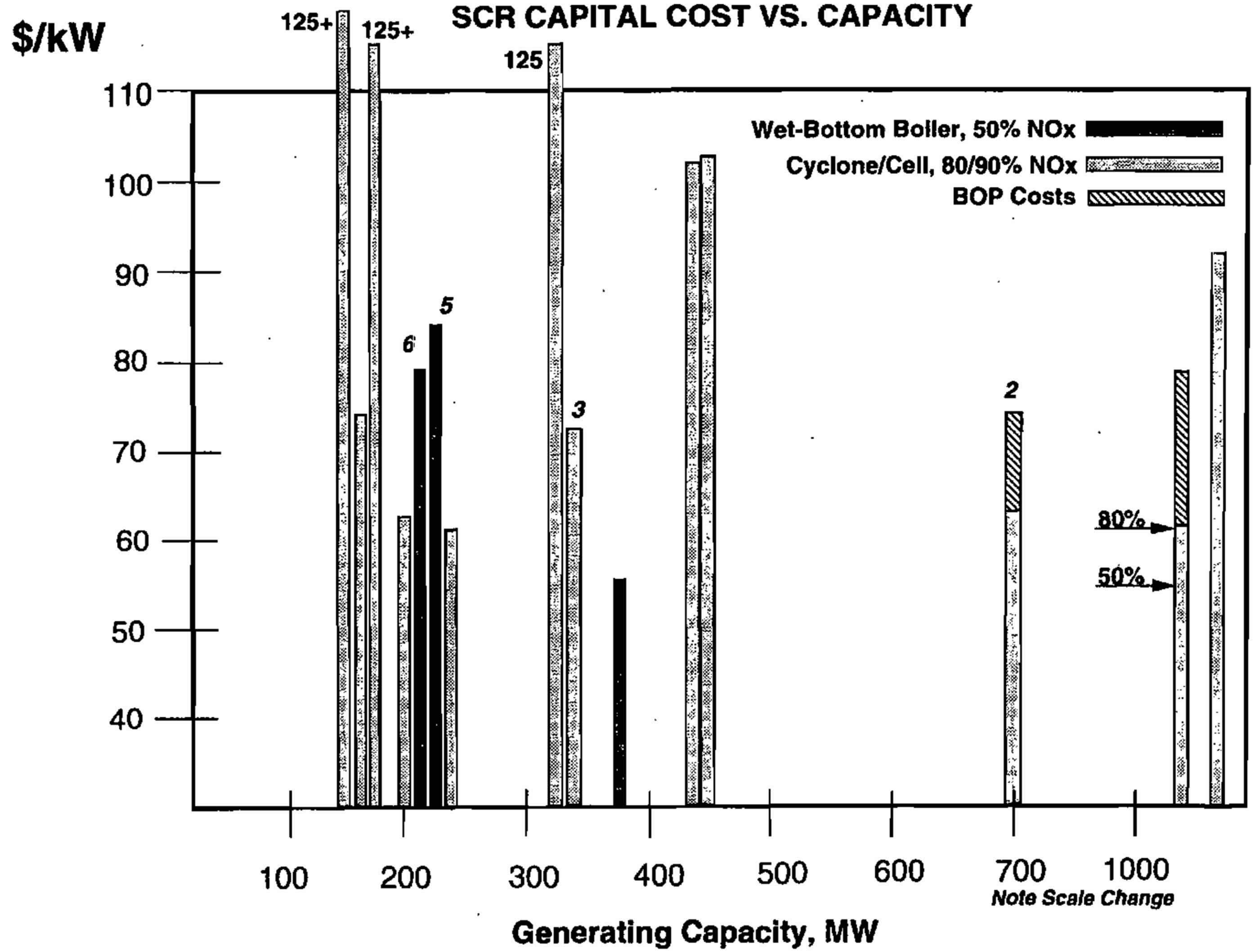

FIGURE 3. RATIO OF TOTAL PROCESS CAPITAL/INSTALLATION, SCR PROCESS/TOTAL PROCESS CAPITAL

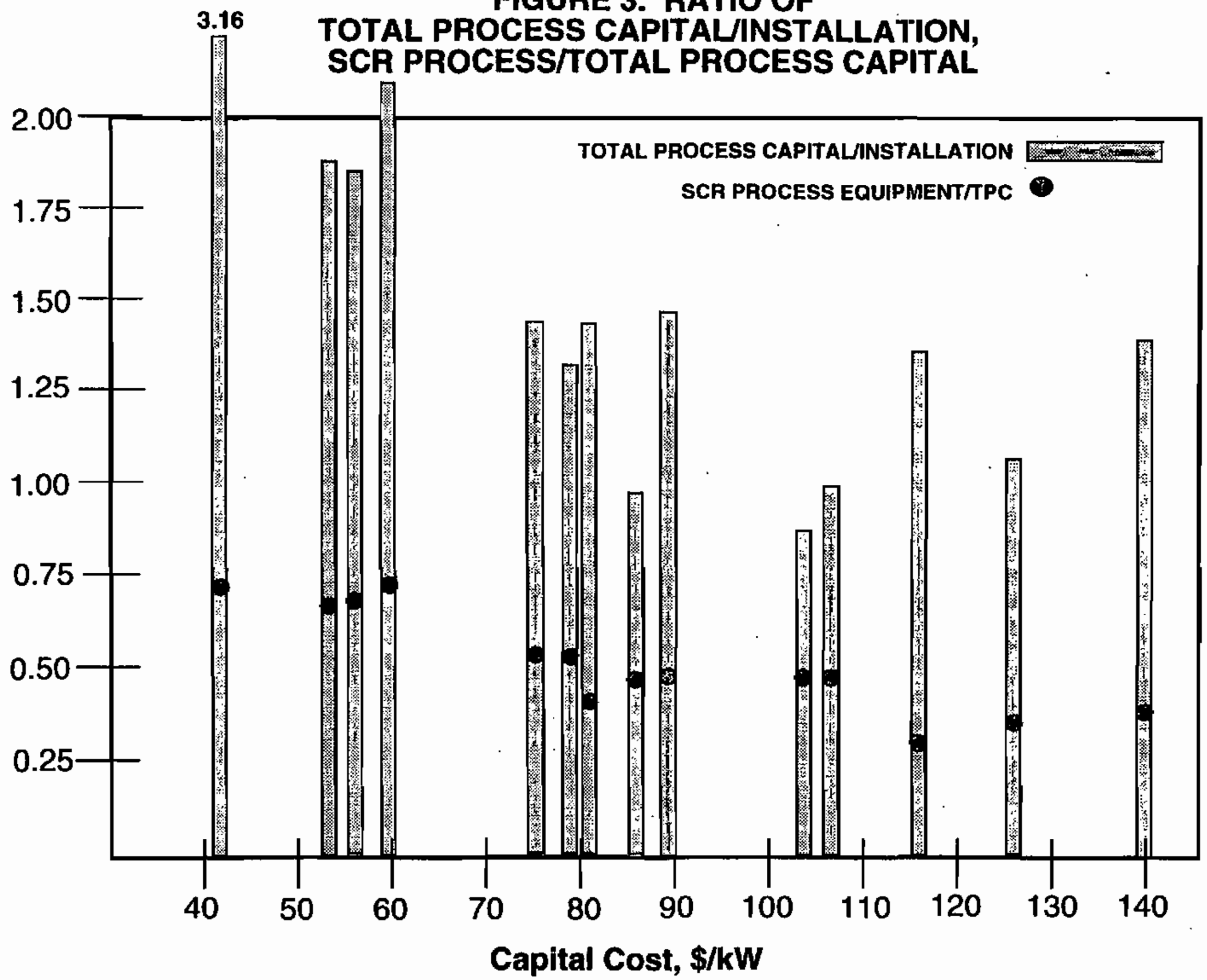

TABLE 2

COST PER TON EVALUATION
SCR ON POST-LNB DRY-BOTTOM, AND GROUP 2 BOILER
(Baseline Case And Sensitivity Analysis)

Evaluation	Process Conditions	Economic Factors	Cost Per Ton $/Ton (NOx)
Baseline: SCR Applied to Post-LNB, Dry-bottom Boiler	80% NOx reduction/ 5 ppm slip, 3200 1/h SV, 4 yr catalyst life *(Baseline)*	$75/kW, 65% CF, 0.15 CRF	**1600 (0.50)** **1768 (0.45)**
Baseline: SCR Applied to Group 2 (Cyclone) Boiler	80% NOx reduction/ 5 ppm slip, 2000 1/h SV, 4 yr catalyst life, *(Baseline)*	$79/kW, 65% CF, 0.15 CRF	**696 (1.3)**
Sensitivity: Incremental Capital (+/- $15/kW)	Dry-Bottom Baseline Boiler Case	same	**Δ 220 (0.50)** **Δ 250 (0.45)**
	Group 2 Boiler Baseline Case	same	**Δ 80 (1.3)**
Sensitivity: Capacity Factor (65% to 85% increase)	Dry-Bottom Baseline Boiler Case	same, except CF	**Δ 340 (0.50)** **Δ 380 (0.45)**
	Group 2 Boiler Baseline Case	same, except CF	**Δ 120 (1.3)**
Sensitivity: Capital Recovery Factor (0.15 to 0.115 decrease)	Dry-Bottom Boiler Baseline Case	same, except CRF	**Δ 650 (0.50)**
	Group 2 Boiler Baseline Case	same, except CRF	**Δ 90 (1.3)**
SCR/Dry-Bottom ($60/kW, 85% CF, 0.115 CRF	Dry-Bottom Case, except as noted	as noted	**935 (0.50)** **1029 (0.45)**
SCR/Group 2 ($60/kW, 85% CF, 0.115 CRF	Group 2 Baseline Case, except as noted	as noted	**424 (1.3)**