Acid Rain Proposals Public Hearing Chicago Ill

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BEFORE THE

U.S. ENVIRONMENTAL PROTECTION AGENCY

PUBLIC HEARING ON)
PROPOSED ACID RAIN RULE)

TRANSCRIPT OF PROCEEDINGS had in the above-entitled matter on the 9th day of January, A.D. 1992, at the Museum of Science & Industry, Chicago, Illinois, commencing at 9:30 a.m.

BEFORE:

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USEPA, Washington, D.C.

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USEPA, Washington, D. C.

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USEPA Regional Office.

REPORTED BY: EDWARD A. GANS, C.S.R.

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HEARING OFFICER KERTCHER: Welcome to the third and final public hearing being held to receive comment on EPA's December 3, 1991 Acid Rain Program regulatory proposals. My name is Larry Kertcher and I am the Chief of the Source Control Branch of the Acid Rain Rain Policy Division. I will be serving as the Hearing Officer for this public hearing.

With me today is Judy Tracy from our Office of General Counsel, and Greg Zurla, on my right, from our Regional Office.

Before we begin to receive your comments, I would like to make some brief remarks concerning the proposed rulemakings and the procedures under which this hearing will be conducted.

With respect to the rules, the principal goal of the Acid Rain Program is the achievement of significant environmental benefits through reductions in sulfur dioxide and nitrogen oxide emissions, the primary precursors of acid rain.

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EPA has tried to develop a workable, flexible, accountable program to achieve the legislatively mandated emissions reductions at the lowest possible cost. At the same time, the acid rain rules implement legislative provisions designed to encourage energy conservation and pollution prevention.

The acid rain rulemaking package proposed on December 3rd is unique for a number of reasons, not the least of which is the fact that it covers four separate but interrelated rules: Acid rain permits, monitoring requirements, S02 emission allowance trading, and excess emissions penalties.

It is our hope that proposing the core program components in this manner will facilitate a broad view of the entire program and help to elicit the most helpful comments possible.

Let me emphasize that we welcome your comments. Up until this time we have run perhaps one of the most open rulemaking

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processes in the history of the Agency. We have received the benefit of the thinking of hundreds of individuals through the Acid Rain Advisory Committee process and additional discussions at other forums.

The proposed rules benefitted greatly from this input, and we expect the final rules to benefit further from the additional comments received during the comment period.

The rules proposed on December 3rd are very important. They affect virtually all utilities in the country. The Clean Air Act Amendments require them to be promulgated by May of 1992. We appreciate your assistance in helping us to promulgate the most workable and effective rules possible.

I will now give a brief overview of each of the rules that we will be hearing comments on today, starting with the permits rule.

The the Clean Air Act Amendments requires that the Acid Rain Program be

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implemented through source operating permits. We have tried to develop the permit requirements to ensure source accountability for emissions reductions mandated by Title IV, yet afford sources the flexible planning opportunities to help minimize the cost of compliance.

Additionally we have sought to assure that the acid rain permit program integrates smoothly with the state operating permits issued pursuant to Title V, yet provide the national consistency necessary to support the allowance trading market.

The acid rain permits rule has several key components, including the requirements concerning certification of the designated representative, permit applications, revisions and challenges, and the selection of certain compliance options provided for in the legislation.

This rule also proposes a procedure for implementation of the Phase I extension provisions of the legislation.

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The allowance system rulemaking was developed to provide sources with the flexibility to meet their sulfur dioxide emissions limitations economically, while providing environmental accountability for collective compliance with the required national cap on S02 emissions.

The proposal establishes requirements for a system for tracking, holding and transferring allowances, as well as for the establishment and operation of allowance accounts. The proposal also includes requirements relating to the distribution of allowances from the conservation and renewable energy reserve.

The continuous emissions monitoring rulemaking, CEM, is designed to measure source compliance and instill confidence in the market-based approach by certifying the existence and quantity of the allowances being traded. The CEM proposal includes requirements for the continuous monitoring of sulfur dioxide,

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volumetric flow, nitrogen oxide, diluent gas and opacity for affected units.

The proposal also contains provisions covering measurement of carbon dioxide, monitor certification procedures, performance verification tests and recordkeeping and reporting requirements.

The excess emissions proposal defines the consequences for and the responsibilities of sources which fail to comply with the Acid Rain Program's sulfur dioxide and nitrogen oxide emissions requirements. The requirements embodied in this rule provide a strong market based incentive for sources to ensure compliance with the reduction requirements of the law.

In summary, EPA has proposed a set of rules which we believe will provide affected sources with the flexibility to make the most cost effective control decisions possible, and the incentives to ensure effective compliance, while at the same time providing certainty that the reduction targets required by the

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legislation will be met.

We have been working on these proposals since the legislation was passed 14 months ago and look forward to hearing your comments.

I would now like to review with you the groundrules for this public hearing.

As discussed earlier, the purpose of the hearing is for EPA to get the benefit of your comments on the proposals. As a consequence, during these proceedings EPA will not advocate any point of view or answer any substantive questions. We will, instead, listen to and record your testimony, and, where necessary to fully understand your testimony, ask clarifying questions.

Presentations will be limited to 10 minutes. The time limit will be enforced, and I will let speakers know when one minute is remaining by holding up a piece of paper which says "One Minute Remaining," which is somewhere on this desk, and when they should end their

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remarks. Any clarifying questions from the panel will be asked following the 10 minute presentation.

A list of speakers scheduled for testimony is available outside this room at the registration table. The list delineates the order in which the speakers will be called. Persons who have preregistered to speak at the hearing will speak first. To the extent we finish early or scheduled speakers are not present, we can schedule additional speakers on a first come-first served basis for the remainder of the day.

Some of you who were not preregistered to speak may have already signed up at the registration desk to be additional speakers. I would like a show of hands right now as to anyone who would like to be added to the speakers's list but has not registered at the desk.

Seeing none, as noted in the Federal Register, if all speakers can be accommodateed

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on the first day of the hearing, we will not hold a second day here. At this time it looks like that will be the case.

However, we will hold open that possibility until later in the day to be sure that other people that would like to present testimony do not arrive in sufficient numbers to require the second day.

When your name is called to speak, you should step up to the podium, announce your name and affiliation, and begin your presentation. We request that if you have not already pre-submitted your remarks to the Public Hearing Hot Line, you make a copy available to the hearing recorder and provide a copy to me prior to your remarks. If you do not have a copy, please submit one to the hearing recorder prior to the end of today's hearing. You should address your remarks to the Panel.

A transcript of this hearing will be made by the hearing recorder and will be placed in the docket at A-91-69, which is the overall

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docket for these rulemakings.

The public comment period for the proposal will remain open until February 3rd. If you have supplemental remarks in addition to your testimony, you may submit them to the central docket section of the EPA at the address listed in the proposal notice. A desk copy of this notice is at the registration table if you wish to copy the address.

Again, I would like to emphasize that we encourage your comments on all facets of the rule. While we have tried to make the proposals as clear as possible, if you have questions or believe that certain provisions are ambiguous, we encourage you to submit comments to that effect, along with recommendations for removing the perceived ambiguity. We are also particularly interested in the practical implications of the provisions which you are concerned about. Case examples are often very effective in helping EPA understand the consequences of the proposal.

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Additionally, while it is important for us to understand your concerns, it is also important to the rulemaking process that you submit comments of support for those provisions which you believe should be retained. Failure to do so could provide an unbalanced perception of lack of support for specific provisions.

Finally, we are committed to promulgating these rules as expeditiously as possible. You can help in this effort by providing any supplemental comments to the docket as soon as possible, but in any event not later than the close of the comment period, which is noted in the Federal Register as February 3rd.

I expect we will take a thirty minute to one hour break for lunch in the event it does not appear we will be finished overall by one o'clock.

With that, I would like to proceed and call the first speaker, who is James McLarney, American Hospital Association.

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Mr. McLarney?

MR. JAMES McLARNEY (Director, Hospital Engineering Services, American Hospital Association, Chicago, Illinois): Good morning. My name is James McLarney, and I am the Director of the American Hospital Association's Division of Health Facilities Management.

We do plan to submit two copies of our comments to the panel by the end of today.

On behalf of the the nation's nearly 5,400 institutional members of the American Hospital Association we welcome the opportunity to testify on the proposed rules of Title IV of the Clean Air Act. All hospitals and many other types of health care facilities have generators to ensure the availability of electric power for life-sustaining equipment during public utility power failures.

The American Hospital Association supports the goal of the Clean Air Act to reduce the adverse effects of acid rain. The rule proposed by U.S. EPA on December 3, 1991 would

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begin the implementation of the Acid Rain

Program by capping sulfur dioxide and nitrogen oxide emissions from electric generators. It would require that existing generators with an output capacity greater than 25 megawatts, as well as all new generators after November 15, 1990, meet these emission caps by the year 2000.

As a first step EPA would require that all operators of affected generators install continuous emissions monitoring systems for sulfur dioxide and nitrogen oxide. In addition, they would be required to apply for a permit certifying their compliance with these new requirements.

Most most backup generators fall under the 25 megawatt threshold for exception from these new requirements. However, the threshold applies only to existing generators, not to new generators. All new generators would be required to have a permit, use continuous emissions monitoring systems and adhere to the

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limitations of the Acid Rain Program.

AHA believes it would be appropriate to exclude all standby hospital emergency generators from these rules. Application of these rules would impose a significant financial burden on hospitals with little gain; it would yield little new information or emissions control from the required monitoring technology, because the generators are used seldom.

Hospitals are required by their voluntary accreditation organizations and by state and federal standards to maintain generators in case of public utility electrical failures to ensure a constant source of power to life-sustaining equipment. Small hospitals typically have one generator; the larger hospitals may have as many as five generators. Between 8,000 and 10,000 of these units are believed to be located in U. S. hospitals. Typically these generators are rarely called into full use. Their usage is usually confined to one or two hours per month to ensure that

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they are operational.

The AHA has compiled cost estimates for continuous emission monitoring systems for generators from four manufacturers. Capital costs range from $200,000 to $300,000 for steam plants and $100,000 to $120,000 for small diesel and dual fuel engine powered generators. Operating costs are expected to be $30,000 a year. These costs would add significantly to the price of new equipment.

The AHA contacted its member hospitals to learn the typical usage of standby generators. Diesel fuel consumption was chosen as a good measure of usage. John Crowley of St. John's Hospital in Lowell, Massachusetts, spoke with six other hospitals in Massachusetts to see how many gallons they burned. He found that those hospitals typically burned from 200 to 400 gallons of diesel each year.

The number of gallons burned depended upon the size of the hospital and how frequently the generators were operated. At St. John's,

for example, a 250 bed hospital, they burned 250 gallons of diesel in 1991 and they expect to burn 300 gallons in 1992. The hospital expects this increase as a result of the procurement of an additional generator.

Emissions from all diesel fired utility units comprise less than one-tenth of one percent of the total utility emissions, and hospitals account for just a small fraction of these units.

Given that the intent of the program is to significantly limit sulfur dioxide and nitrogen oxide emissions, very little emissions control will be achieved by requiring such small systems, used so infrequently to adhere to the Acid Rain Program rules. Large sources of sulfur dioxide, such as industrial facilities, are exempt from the Acid Rain Program. Hospital sources contributing such a small amount of sulfur dioxide should also be exempt from such costly regulation.

In summary, the imposition of these

requirements on units that contribute so little to the problem would provide no real benefit to the Acid Rain Program's objectives, while being very costly to hospitals that have replaced generators since 1990 or that will replace generators in the future.

Most importantly, these costs would redirect scarce resources from hospitals' primary mission, and that is the care of patients.

Again, the American Hospital Association would like to thank the Panel for the opportunity this morning to present our comments. We would be very happy to answer any questions you might have.

HEARING OFFICER KERTCHER: Thank you very much for your testimony. We will move to the next speaker, then.

Tom Zordan, Science Applications International Corporation -- if Mr. Zordan is not here, nor a stand-in, we will move to the third speaker, who is Jack Kegel, Iowa

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Association of Municipalities.

MR. JACK KEGEL (General Counsel, Iowa Association of Municipal Utilities, Des Moines, Iowa): Good morning. My name is Jack Kegel. I am General Counsel for the Iowa Association of Municipal Utilities. Our association represents the interests of more than four hundred cities which operate electric, gas and water utility systems throughout the State of Iowa. Our membership includes 134 of Iowa's 137 municipal electric utility systems.

I would like to take just a moment to tell you a little about Iowa's municipal electric utilities. Iowa is a small state. Our entire population is less than that of the City of Chicago, where we are today. We don't have any large cities, and we have only a handful with populations over 50,000. The essence of Iowa can be found in the hundreds of small farm communities which dot the landscape every few miles from border to border.

By and large, our municipal electric

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utilities serve these small communities. We have only three utilities, those at Ames, Cedar Falls and Muscatine, with 10,000 customers or more. We have one other system, Spencer, that has more than 5,000 customers. That leaves 97 percent of our municipalities with fewer than 5,000 customers. 116 of our systems, about 85 percent, have fewer than two thousand customers, and about 60 percent of our systems have fewer than a thousand customers. 30 percent actually have fewer than five hundred customers. And they are the very smallest communities in Iowa.

These very small utilities have been

providing quality service for generations, and in many of these communities the presence of a municipal electric utility has been a key factor in maintaining a healthy local economy through the agricultural depression of the 1980s.

But a utility with five hundred or a thousand or two thousand customers operates with a small staff, whose time is fully committed to operating and maintaining the system. There is

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little staff time available to take on significant new duties, and these utilities have relatively low kilowatt hour sales with which to recoup large capital costs.

We hope that when the final regulations are issued under the acid rain portion of the Clean Air Act, EPA will bear in mind that these regulations don't apply only to huge corporations with hundreds of millions of dollars in annual revenues. They also will place a heavy regulatory burden on these small systems with 500, 1,000, or 2,000 customers.

We believe there are several ways EPA can mitigate the burden on small systems without weakening any way the effectiveness of the Clean Air Act. I would like like to address some of those.

The first area I would like to address concerns small unit generation. Many of our members own and operate diesel and dual fueled internal combustion generating units. By and large, these units are very small. Of 273

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internal combustion units included in our 1991 survey, only 7, that is 2.6 percent, exceeded 5 megawatts in capacity. Further, these units operate only during peak hours or as standby units in case of emergency outage.

Of our 273 internal combustion units, only 3 had a capacity factor of greater than two percent. That is 175.2 hours of operation in the entire year. The average capacity factor for all units was 0.46 percent, which is only 40.3 hours of operation per year.

Every one of our units that operated at a capacity factor of one percent or greater, which is 87.6 hours per year, is dual fueled and runs primarily on natural gas. Emissions from these units are absolutely minimal.

Over the next 5 to 10 years a number

of our members may see a need to install new very small units similar to the ones I have just described. Given the minimal emissions from these units and the few annual hours of operation, we believe that very small units

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should be exempted from the rules.

We recommend an exemption from the rules for units of 5 megawatts or less, and we would also recommend that small units above 5 megawatts in capacity, in the 5 to 10 megawatt or 5 to 15 megawatt range, also be exempted if they meet limitations on annual hours of operation.

I would also like to discuss the question of alternatives to CEMs for internal combustion units. We have worked very closely with our national affiliate, the American Public Power Association, in developing an alternative protocol for diesel and dual fueled units. We know that the EPA staff has worked very hard on this issue, and we appreciate the effort that has gone into developing the alternative to CEMs in the proposed rule.

We believe that a lot of progress has been made in developing a workable alternative for new internal combustion units, but we still have a ways to go.

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The proposed rules would still require new, very small diesel units to install NOx and opacity monitors, as well as conducting extremely stringent fuel sampling and analysis for S02. If these requirements remain in the final rule, we are afraid new small diesel units will be virtually eliminated as a viable option for our member utilities.

These new units, just like the current ones, would be intended to operate only a few hundred hours a year. And, as we see it, the annualized costs of emissions monitoring alone required under these rules at a new small diesel would roughly equal the entire annual revenue produced by the unit.

Offering an alternative to CEMs for S02 offers little meaningful savings for a new diesel if NOx CEMs and opacity monitors are still required. We have to find a more cost effective approach for these units.

EPA should allow oil-fired and

gas-fired units to use a reasonable and
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practicable NOx CEMs alternative based on emissions factors drawn from load curves produced from a stack test performed every five years upon permit renewal or after 365 days of operation, whichever occurs first.

Oil-fired diesels should be exempted from opacity monitoring. As we have noted, these units operate few hours in a year and produce de minimis emissions. The same considerations that led EPA to exempt gas-fired units from opacity monitoring in the proposed rules support an exemption for oil-fired units as well in the final rules.

We also have several concerns regarding the alternative S02 oil sampling and monitoring procedure. It would require hourly automatic as-fired oil samples blended into a 24-hour based composite sample, which must then be sent to a labor on-site facility for sulfur content analysis, with results returned within 24 hours. The proposed rule also requires analysis of daily oil samples for oil heat
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content.

Hourly fuel sampling would be time consuming and expensive. It would likely not be cost effective for a small diesel unit which operates at a capacity factor of one to two percent. The requirement to return results of lab testing of oil samples within 24 hours will not increase the accuracy of the monitoring, and it will be virtually impossible to meet for small utilities which don't have testing facilities on site. Daily heat consent analysis may be appropriate for the heavier varied oils burned in large oil-fired steam units, but it is not appropriate and is not needed for the constant heat content of the fuels used in internal combustion units and in combustion turbines.

EPA has asked for comment on the appropriateness of using less precise, less continuous samples in exchange for a default value for sulfur content. The default value would be the highest measured value in the last
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30 days. We believe that use of this or some other appropriate default value is a far better

approach. We strongly urge EPA to include use of a default value for sulfur content in the final rule.

In large measure, the alternative S02 oil sampling and monitoring protocol was designed for large, oil-fired steam generating units. We believe that the protocol should be modified to include reasonable and practicable proposals that are more appropriate for engines as opposed to boilers. The procedures developed by Kilkelly Environmental associates for the American Public Power Association provide a workable alternative, and we urge EPA to adopt these or comparable proposals in the final rule.

I would like to turn now from small units to an issue that relates to large, jointly-owned base load units. Many of our members have minority interests in large baseload coal units operated by other

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utilities. We believe that the rules need to provide additional protections for minority owners in the selection of the designated representative.

We urge EPA to require unanimous consent of all co-owners for the selection of a designated representative and establishment of a designated representative agreement. We believe that this is consistent with Congress's intent to protect the interests of minority owners. If unanimous consent is not required, we believe EPA at a minimum should provide that minority owners have some measure of control over the use of their proportional share of the allowances allocated to the unit, particularly if the allowances are not required for operation of the unit.

A closely related issue concerns liability of co-owners. The proposed rule eliminates the "joint and several liability" language of the draft rule, but there is little practical change in the distribution of

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liability among owners. The current language would still make minority owners liable for the compliance activities of the operator.

The concept of joint and several or shared liability has been used effectively as an enforcement tool in other areas, such as the

Superfund program, and it may be an appropriate enforcement mechanism when it is likely that the party against whom enforcement should be directed cannot be reached.

In the Superfund program, for example -- we don't believe that is the case in this program. We believe that the operators of Title IV sources are stable entities. EPA will clearly be able to reach the operator of a unit without having to extend liability to the other owners.

We urge EPA to give full consideration to Section 810 of the statute, which requires EPA to "determine the impact on small communities." The preamble to the rules states that "EPA has provided all the relief available

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under the statute to help the most affected small utilities." We disagree that all available steps have been taken at this point.

We have outlined a number of steps today. There are some in my comments which I have not had time to address which EPA could take to lessen the heavy burden of compliance for Iowa's municipal utilities. I believe the modifications we propose are well within EPA's discretion under the statute and would further the congressional mandate set out in Section 810. We urge EPA to adopt these recommended modifications in the final rule.

Finally, I would like to extend my appreciation and that of all of Iowa's municipal electric utilities for the opportunity to present our concerns at this hearing.

Thank you.

HEARING OFFICER KERTCHER: Thank you.

The next speaker is Michael Menne of Union Electric Company.

MR. STEVEN C. HUGHES (Engineer, Air

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Quality Program, Union Electric Company, St. Louis, Missouri): Good morning. My name is Steven Hughes. Mike Menne had a death in the family yesterday and wasn't able to make it, so I am filling in for him.

I am an engineer in the Air Quality Program for Union Electric Company, located in St. Louis, Missouri. Union Electric Company is an investor-owned electric and gas utility serving over one million customers throughout

Missouri, West Central Illinois and Southeastern Iowa.

The Title IV regulations will have a significant impact on Union Electric Company. The company owns and operates six Phase I affected units and twenty units that will be affected under Phase II. Detailed written comments on the proposed Title IV implementation regulations will be provided before the comment deadline in February, but today I want to emphasize just a few points which are particularly troublesome to Union Electric.

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The first major concern to the company involves the extensive liability of the designated representative in the permit section under Part 72. According to Sections 72.7 through 72.9 of the proposed regulations, the DR will be held liable along with owners and operators of affected units for any data, plan or compliance issue regarding the affected units the DR represents.

In addition, the DR must sign a sworn statement that all information in each submittal is, at least to the DR's knowledge, true. The DR is expected to interrogate those who supply him with the information. Section 72.8 is particularly disturbing, because it makes it a violation to delegate any responsibility to take any action or comply with any standard or requirement of the Title IV rules.

These requirements combine to make the DR a person who must do the following: He must personally verify all submitted information as correct, including compliance plans, permit

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applications, monitoring plans, QA procedures, generation and emissions data. In addition, he must be in a position of control over the operation of the affected units. He must be in a position to immediately take actions to rectify noncompliance conditions. He must be in a position to take action on continuous emissions monitoring operations and problems. And, in addition, he is the only person able to submit forms or negotiate with the Agency on compliance issues.

To sum it all up, he has got a lot on his back.

Most utility management structures do

not provide for a person to be capable of handling such responsibilities. While we totally recognize and understand the need for the Agency to want to specify a single individual to represent an affected unit, there must be some means established to limit the personal liability of the DR from operations which are not under his or her control.

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We recommend that the wording of Sections 72.7 through 72.9 and throughout the regulations be modified to allow for the designated representative to be the person who legally represents an affected unit for purposes of supplying the required information to the regulatory agencies, yet limit the ability of the Agency to enforce personal criminal penalties against the DR for operations over which he has no control.

We also recommend deleting that portion of 72.8 which prohibits the delegation of responsibility. As currently written, the designated representative, owner or operator, must physically perform all tasks associated with compliance in order for that person to be certain that each action taken will not result in personal criminal action.

At this point I would like to make some comments on Part 75 of the Continuous Emissions Monitoring.

Union Electric has been monitoring S02

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for over a decade on six of our coal-fired units, so we do have some experience in the field of monitoring S02.

The first comment has to do with the missing data scheme. In order to provide the backup data necessary for the proposed missing data scheme, coal samples must be taken every six hours on every coal-fired affected unit following ASTM methodologies. This requirement is very costly and overconservative.

As a company which operates 12 coal-fired units affected by this provision, this requirement would cost Union Electric tens of millions of dollars for sampler installation, maintenance, physical transport of samples, analytical laboratory analysis of the samples, and data analysis.

This is a extreme for backup data when

CEM instrumentation is not available. For those units which intend to comply with acid rain sulfur limitations strictly through the use of lower sulfur fuels, missing data should be

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filled in through interpolation routines. Other statistical methods should apply to those units where flue gas desulfurization or other chemical or mechanical controls are applied.

One of our big concerns is complexity of the missing data schemes as it is currently written, in addition to the cost involved with the coal sampling. We would like to see a much cleaner approach, where you are just looking at the previous CEM data, more like what was in the draft rules last summer.

My second comment has to do with the bias test portion of the relative accuracy audit.

The proposed method of applying a bias test to the relative accuracy audit is not appropriate. For one, if the Agency believes this test is statistically valid and the bias test is used to adjust data when readings are biased low, then adjustments should also be allowed to data when readings are biased high. It only makes sense that if this is a

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statistically valid procedure, it should be available in both directions. Otherwise, severe allowance penalties will result when readings are adjusted for bias.

I have taken some of our previous stack test data and applied the bias test to them. The penalty will be quite excessive now. We agree -- I should say we don't have any problem with the Agency making the missing data procedures in such a way that it penalizes you for not having the availability. But, based on the data that I have put together, this missing data procedure -- this bias test will really penalize Union Electric a severe amount.

Secondly, bias should not be based on once or twice a year stack tests. If possible, Union Electric would like to see this bias test not applied on a semiannual or annual basis when a stack test is done. We would like to see it done as an adjustment to the zero and span checks done each day similar to what is done in method 6(C).

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There are many more sources there in the reference method stack tests than you see on zero and span checks each day. But what really bothers us about only applying it to the stack test is that there are so many variables that could change from week to week.

Even if EPA lowers the protocol, if you change your cal gas out, plus or minus two percent of the protocol on gases, you could still change your gas model out from one day to the next, and it would be a change of 4 percent if you are two percent in one direction the first day and two percent in the other the next day. There are so many things that could change during the stack test, that to be penalized for the next six months because that doesn't seem appropriate.

That concludes my comments on the bias test.

The next comments have to do with the requirements for NOx and opacity monitors on our oil and/or gas-fired units.

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We believe the requirements for NOx and opacity CEM installations should be waived for all oil and/or gas-fired units, particularly those units which have a low capacity factor. Many older units exist across the country, particularly in urban areas, which are used primarily to supply power during periods of peak demand. These units are not economical to operate on a continuous basis. Congress limited the NOx reduction program to coal-fired units in the Clean Air Act, and therefore we find no basis for requiring NOx monitors on such peaking units.

NOx emissions, if needed, could be estimated through various emissions factors calculations.

Opacity and NOx emissions are typically intermittent, quite low, and maybe insignificant from such sources. According to the proposed regulations, Union Electric Company will be required to spend millions of dollars in capital and operations and maintenance costs for

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establishing CEM systems on 8 oil and/or gas-fired units which only run a limited number of hours each year. The contracting, stack sampling, maintenance force, engineering, lab work, data analysis and reporting, which is part of the CEM requirements, would hardly seem justified for such a small source of annual emissions.

We strongly urge EPA to waive the NOx and opacity CEM requirements for oil and/or gas-fired units. If this is unacceptable, then EPA should waive these requirements for oil and/or gas-fired units which operate below a defined capacity factor, and we recommend that capacity factor be in the neighborhood of 30 percent.

The only comment I would like to make in regard to this NOx and opacity problem is in many cases we will be required to fire these units simply to do the semiannual or annual stack tests. In that case, we wouldn't even need the generation. These units operate on a

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much higher cost per kilowatt hour than any of our other units. So it would be quite a penalty to have to do that.

The last item I would like to talk about has to do with the 10 percent relative accuracy requirement on the combined S02 velocity, which would be required to the year 2,000. We don't feel there is enough data available at this time to substantiate that we can obtain that 10 percent. We would like to see that delayed until later in the 1990s -- 1998 -- at which time, if it is appropriate, the Agency can propose that portion of the regulation.

I appreciate having the opportunity to express our views at this hearing.

HEARING OFFICER KERTCHER: Thank you.

Our next speaker will be David Baker of the Illinois Department of Energy and Natural Resources.

MR. DAVID BAKER (Manager of Policy, Illinois Department of Energy & Natural

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Resources, Sprinfield, Illinois): My name is David Baker. I am Manager of Policy Research for the Illinois Department of Energy and Natural Resources.

This testimony is intended to register initial concerns regarding the proposed rules on the national Acid Rain Program issued by the

U.S. EPA on December 3, 1991. The State of Illinois may also submit additional comments on the proposed rules before the deadline in February.

The State of Illinois and its affected agencies of government recognize and accept both the difficulty and importance of establishing both an effective and economical national program to ensure clean air, including the Clean Air Act Amendments of 1990. Illinois government has already taken significant steps through recent legislation and administrative actions to ensure Illinois sources comply with Title IV of that federal law, and you may expect that Illinois will meet or exceed emission control

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requirements of Title IV of the act in a timely manner.

However, such actions to achieve the environmental betterment can be taken only at a cost. The enormous near-term costs which Illinois and other high sulfur coal producing states will experience as a result of Title IV implementation have already become apparent. Electric utility customers in Illinois will pay in the range of $200 million or more annually for electricity to reduce emissions of sulfur and nitrogen oxide. While this cost is significant, the cost to the coal industry in Illinois and the related regional economy will be devastating.

Illinois is a supplier of fuel to a dozen states in the Midwest and Southeast. Forty electric utility companies, owning 106 Phase I affected units, burn Illinois coal. The Illinois Department of Energy and Natural Resources recently surveyed the 30 utilities which annually burn 50,000 tons or more of

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Illinois coal. Sixteen of them plan to reduce or eliminate their purchases of coal from Illinois as a part of their compliance plans. Only 5 have plans for the installation of flue gas desulfurization. Overall we expect a loss of 26 to 38 percent of our coal sales, a loss of three to four thousand mining jobs and perhaps seven to eleven thousand related jobs.

The ten-county region that will be hardest hit will experience an unemployment rate of over 20 percent. Demands on state government services will grow significantly, and state and local revenues from the economic activity in that region will decline. Other states in the Midwest will also face the dual repercussions of higher utility costs and lost economic activity.

The State of Illinois emphatically maintains that the Agency must take deliberate cognizance of these circumstances and the unfair burden which they represent in the formulation of its final rules to govern Title IV. The self

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evident obligation in promulgating such rules is to use its discretionary powers to ensure regional fairness and to avoid further economic harm to Illinois and similarly situated states to the fullest extent possible.

With regard to the particular provisions of the proposed rules, the State of Illinois believes that the Agency has both the power and the duty to encourage the deployment of quality control technology which permits the use of high sulfur coal.

The preamble to the proposed rules notes, and I quote, "Section 404(d) was included in the act to reduce the impact of the acid rain reduction program on employment in high-sulfur coal mining communities and to defray the compliance costs and consequent electric rate increases that would otherwise be charged by some of the utilities using high sulfur coal." And the Congressional Record was cited in making that statement.

The clear and undisputed intent of

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Section 404(d) was to foster the installation of 90 percent control technology, that is scrubbers, as a method of compliance by rewarding such actions vis-a-vis others, such as fuel switching, which would reduce high sulfur coal use.

Consequently, the State of Illinois must take serious umbrage with the Agency's proposal for Phase I early extension ranking procedures at Subpart L of Part 72 of the proposed rules. The proposed telephone queuing procedure for determining order of receipt of applications undermines the clear intent of Section 404(d) of the act and ignores the Agency's discretionary authority to allocate

Phase I extension allowances on other bases that would be more appropriate or more consistent.

The phone queuing procedure unnecessarily fosters uncertainty about the likelihood of obtaining extension allowances, thereby substantially reducing their expected value to utilities which might seek them. As a

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result, the many utility companies for which scrubbing and switching compare closely in cost are already favoring the latter option. Only five utilities that burn Illinois coal and approximately 20 utilities nationwide are seriously considering installation of scrubbers.

Rather than encouraging the maximum amount of technological control in Phase I, the proposed rule is discouraging at least some utilities from adopting them. Most of the alternatives to the telephone queuing procedure described in the preamble to the Proposed Rules, namely the modified phone queue approach, the lottery, the date stamp and the stand-in-line, have this same shortcoming. All of these approaches undermine the intent of Congress in Section 404(d).

Unfortunately, the agency's interpretation of Section 404(d)(3) reflected in proposed Subpart L focuses narrowly and inappropriately on only a portion of the

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relevant statutory language. I cite the language in here. I won't read it.

The fundamental error in the Proposed Rules is the assumption that Section 404(d)(3) requires each applicant be either approved or denied the full amount of eligible extension allowances. The act contains no such all-or-nothing requirement.

The final action referred to in the first sentence of that section does not require total approval or total rejection of a proposal. It only requires a decision that is consistent with the authority granted to the Agency in the second sentence of that section. That second sentence allows approval in whole or in part and with any necessary modifications or conditions.

It is difficult to imagine that any member of Congress who voted for passage of the

Clean Air Act Amendments of 1990 envisioned a circumstance in which the EPA would allocate extension allowances based on a telephone queue

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which separates applicants by milliseconds or nanoseconds.

Only one of the alternatives described by the Agency is within its administrative discretion and consistent with the intent of Congress. This is the pro rata allocation approach. As explained in the preamble, the Agency has the discretion to provide that all applications received on a given day would be considered to have been received at the same time. And if the extension allowances are oversubscribed, the Agency, as well, has the clear authority to approve requests for extension allowances on a pro rata basis.

As the language in there says, the Administrator may approve an extension proposal in whole or in part and with such modifications or conditions as may be necessary.

Finally, the EPA also acknowledges in its preamble that a pro rata allocation could encourage the installation of more control technology than the other alternatives.

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This is what Congress intended. The pro rata distribution is most consistent with that intent to maximize the installation of control technology and minimize the detrimental effects on high-sulfur coal states. Its own Advisory Committee, the Acid Rain Advisory Committee to the EPA in the report from its Permits Subcommittee, recommended adoption of the pro rata approach.

We believe, therefore, for all of the above reasons, that the Agency has the duty to adopt the pro rata approach in its Phase I early extension ranking procedures.

We recommend that the Agency consider all applications received on a given day to be received at the same time, and, if extension allowances are oversubscribed, that the Agency allocate them on a pro rata basis. We believe this rule could and should be adopted in a timely manner to allow utilities to make decisions about their Phase I compliance plans.

I would like to thank you on behalf of

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director John S. Moore of the Illinois Department of Energy and Natural Resources.

I would just like to say one more thing. Separate from the testimony, when I heard that you were holding the hearing at the Museum of Science and Industry here, I assumed you would be holding it in the coal mine. (Laughter).

Thank you.

HEARING OFFICER KERTCHER: Thank you.

The next speaker will be Marty Blake, Louisville Gas and Electric Company.

MR. MARTY BLAKE (Director, Regulatory Strategies, Louisville Gas & Electric Company, Louisville, Kentucky): Good morning. My name is Marty Blake, and I am the Director of Regulatory Strategies of the Louisville Gas and Electric Company.

LG&E appreciates the opportunity to submit oral comments on the Environmental Protection Agency's proposed rules which were published in the Federal Register on December 3,
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1991, implementing the Clean Air Act Amendments of 1990.

In order to implement the market-based approach adopted by the Congress in the amendment, it is critical for EPA's regulations to provide utilities with the flexibility to achieve S02 reductions in the most cost effective manner possible. All 8 of LG&E's coal-fired electric generating units are fully scrubbed. In 1991 LG&E had a system-wide average annual S02 emissions rate of about 0.85 pounds per mmBtu, with its best unit having an annual average S02 emissions rate of about 0.52 pounds per mmBtu. All 8 of LG&E's coal-fired electric generating units meet the Phase II S02 requirements and LG&E's scrubbers prevented about 116,000 tons of S02 from being emitted into the atmosphere in 1991.

The current compliance status of companies like LG&E allows those companies to play an important role in helping Phase I-affected utilities to meet their S02
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reduction obligations. LG&E wants to assist in accomplishing this by using its scrubbed units as compensating generation and as compensating units for utilities with Phase I affected

units.

The ability to purchase compensating generation from these LG&E units could greatly assist other utilities with Phase I units in dealing with any unplanned underutilization problems on a timely basis in order to comply with EPA's regulations. These units will provide a ready source of compensating generation, which, because of their low emission rates, could help other Phase I utilities to minimize the year-end surrender of allowances required under the regulations in the event of net underutilization, caused, for instance, by forced outages.

Creative use of reduced utilization options will help to realize the efficiencies and compliance cost reductions which Congress envisioned coming from market-based solutions.

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LG&E believes that the proposed rules will facility the implementation of these reduced utilization options. The rules proposed by EPA are a significant improvement over the OMB/ARAC draft of June 21, 1991, in the areas of NOx emissions limitations for compensating units, the requirements for designated representatives for utilities using reduced utilization alternatives, and representatives for utilities using reduced utilization alternatives and in clarifying the treatment of joint and several liability.

It is clear that EPA is trying to make the market-based approaches to compliance with the Clean Air Act Amendments viable alternatives for utilities with Phase I affected units without any degradation of the air quality improvements which the amendments envision.

The proposed rules provide the flexibility necessary for utilities with relatively low average annual emission rates to participate in reduced utilization alternatives

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and to come into compliance earlier than is specified in the amendments.

A critical element in determining the viability of implementing reduced utilization alternatives for compliance is the treatment of NOx emission limitations. Through its comments today, LG&E supports the proposed treatment of NOx emission limitations on non-designated Phase

I utility generating units, specifically "compensating units."

Congressional intent is clear, that one of the major goals of the amendments was to achieve S02 reductions in the most cost effective manner. The proposed exemption from the Phase I NOx control requirements provide a significant incentive for the utilities to explore and adopt cost effective compliance plans without risking double jeopardy with respect to NOx controls on units that Congress did not specifically identify as requiring Phase I NOx reductions.

The double jeopardy would be a result

of the application of Phase I NOx controls followed by a second more stringent Phase II NOx emission limitation and the associated additional controls. Such treatment is not cost effective, in that installation of low NOx burners at $25 to $40 per kilowatt to attain an emission rate of .45 to .50 pounds per mmBtu would be followed by further and as of yet indeterminate investments to achieve more stringent Phase II limitations.

Thus, the investment in Phase I technology might be wasted if the achievement of the Phase II allowable NOx emission rates is not possible with low NOx burner technology. Subsequently, significant reinvestment in NOx abatement technology might be required.

The proposed regulation also eliminates another potential double jeopardy situation with respect to NOx emission limitations. There currently exists substantial uncertainty concerning the treatment of NOx emissions from utility units in a ozone

non-attainment area. Were a unit to be subject to Phase I NOx emission limitations solely due to its designation as a compensating unit and then further be subject to NOx emission limitations pursuant to Section 182(f) of Title I, it would subject the unit to excessive and unnecessary NOx reduction costs.

The proposed treatment allows for the proper development of Title I NOx regulations for utility units in ozone non-attainment areas. Absent such treatment, units in ozone non-attainment areas would risk making significant investments in NOx reductions, only to find out that those reductions aggravate ozone formation, as alluded to in Section 182(f).

The proposed treatment allows EPA to give due consideration to the NOx volatile organic compound study required in Section 185 B and thus allows consideration of all pertinent information before mandating what may prove to be unnecessary NOx reductions.

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LG&E believes that the current proposed treatment of NOx emissions for non-listed Phase I units is consistent with congressional intent, recognizes the risk associated with premature NOx limitations in ozone non-attainment areas, and provides some cost certainty for utility units contemplating designation of compensating units as part of their compliance plans, thus playing an important role in the development of an efficient allowance market.

If the proposed treatment of NOx emission limitations on non-designated Phase I utility generating units is not retained, LG&E believes that there will be few, if any, utilities interested in offering to use their clean generating units as compensating units for other utilities. Thus, it is necessary to retain the proposed treatment if the compensating unit provision is to contribute to the achievement of the congressional goals of air quality improvement and compliance cost

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minimization.

Louisville Gas and Electric Company would like to thank EPA for the opportunity to make these verbal comments this morning. Thank you very much.

HEARING OFFICER KERTCHER: Thank you.

Our next speaker will be Bill Washburn, the Missouri Public Services Commission.

MR. BILL WASHBURN (Manager, Policy & Federal Department, Missouri Public Service Commission, Jefferson City, Missouri): My name is Bill Washburn. I am Manager of Policy and Federal Department, Missouri Public Service Commission -- I know it is on the list as "Public Services," but it is still "Public Service."

We appreciate the opportunity to present these comments today.

The Public Service Commission of the State of Missouri files these comments concerning the notice of proposed rule making published by the Environmental Protection Agency

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in the Federal Register on December 3, 1991.

The MoPSC is a governmental Agency created under the laws of the State of Missouri with jurisdiction to regulate electrical corporations in the State of Missouri, including the rates and charges for the sale of electricity to consumers within the state. Therefore, the Missouri Public Service Commission has a significant interest in the implementation of the Clean Air Act Amendments of 1990 and the effect of such implementation on electrical utilities and their customers.

As Section VI.A.2. of the preamble of the proposed rules points out, in order to properly function, the Clean Air Act Amendments depend on the accurate measurement of the actual quantity of S02 emissions from affected units. In place of the measurement of the gas concentrations required under previous legislation, the Clean Air Act Amendments require that the emissions from the regulated plants be measured in tons of sulfur dioxide.

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In fact, the entire allowance trading program seems to be predicated upon the belief that instrumentation exists which can accurately measure the tons of sulfur dioxide being emitted when such instrumentation is installed at a typical power plant.

As proposed, the EPA would require that a power plant's exhaust gas velocity be measured. This arises from the need to report emissions in tons rather than a concentration -- i.e. parts per million. The accuracy of the measurement of a plant's emissions in tons is at best no better than the accuracy of the measurement of the gas flow rate. We believe that the assumptions of the EPA regarding the accuracy of the instrumentation necessary to make these measurements are flawed.

We make this statement based on a survey of the regulated electric utility in Missouri regarding their experience with the instrumentation necessary for the measurement of exhaust gas flow. Their independent but

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unanimous response conveyed very little confidence in the accuracy of this type of instrumentation when placed in in exhaust gas stream of a coal-fired boiler. The biggest reason for this lack of confidence was the recognition of the problem of stratification of the gas stream flow. The problem of locating the flow measurement transducers within the exhaust gas system, so that they will produce measurements falling within the EPA's proposed relative accuracy and bias requirements under the full range of plant loads, operating conditions and atmospheric conditions is seen as one with which neither the utilities nor the EPA have had much experience. Furthermore, our information indicates that even in the area of S02 measurements, the proposed EPA bias test will be difficult to pass without repeated and expensive retests.

We requested data from the regulated electric utilities in Missouri regarding results of recent S02 tests conducted at several

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different plants, each using state of the art equipment. These tests showed a 40 percent failure rate of the bias test as it is currently proposed.

An analysis of the proposed EPA procedures quickly reveals its basic weakness, one that received very little attention in the EPA's discussion of the proposed rule. Although the drafters of the Clean Air Act Amendments assumed that instrumentation was available which would accurately measure the total quantity of sulfur dioxide being emitted by a power plant, apparently no consideration was given as to how this instrumentation was to be calibrated.

The currently proposed EPA methods are the same time-worn tests that the EPA has been using for years, but they are now being extended to flow measurements. They are awkward, time consuming to undertake, since they are often performed on a stack 200 or more feet off the ground on a very exposed platform by a set of transducers mounted on lances and extended into

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the stack. Taking a set of measurements is so time consuming that only a limited number of samples can be obtained transversing the stack, and by the time one settlement is complete, the fuel, operating conditions, or atmospheric conditions may have changed sufficiently to introduce significant errors into the measurements.

The EPA appears to have taken the position that, given the reliance on the Clean Air Act Amendments on CEMs, it should formulate its rules and its penalties under the assumption that the results from the reference calibration methods are in fact correct, when in fact they may not be any better than the accuracy of the instruments they are supposed to be checking.

Our data indicate that during the periodic retests of CEMs, the bias tests proposed in Appendix A to Part 75 will probably cause the most failures. Thus, we have concentrated our comments on this part of the proposed rules.

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We would note that EPA's original OMB/ARAC draft of the proposed rules provided that if a CEM failed the bias test during a periodic retest, the owner might be subjected to penalties for overcompliance with the law. For example, assume that during a periodic retest a CEM was found to be reading high when compared to the reference calibration method to the extent that it failed the bias test. Although the owners would already have been penalized by using up allowances at a rate faster than if the CEM readings accorded with the reference calibration method, the CEM would also be declared to be inoperative, thus increasing its out-of-service hours and subjecting its owners to more severe penalties under the out-of-service provisions of the rule.

There was considerable criticism of this overly harsh provision, and the EPA has commendably changed it in the latest draft of the proposed rules. However, the rules currently proposed by the EPA are unfortunately

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not much of an improvement. Under the rule as proposed, CEMs can only fail the bias test if they are reading low enough to fall below a certain allowable range centered on the average measured by the reference calibration method.

In statistical jargon, this type of criterion is called a one-tailed test. Using a one-tailed test in the context of this rule may at first seem to be a significant improvement over the previous version of the rule. Nevertheless, what it actually creates is essentially a no-win situation for the utility and eventually its customers, that is to say that there are no winners unless the EPA believes that a reduction of S02 beyond the goals of the Clean Air Act Amendments by means of administrative rule making is a desirable goal.

According to Paragraph 7.6.5 of Appendix A to Part 75, if during a periodic performance test a CEM measures sufficiently less emissions than the reference calibration method, it fails the bias test. Until the CEM

is retested, the owners are required to calculate a factor, greater than one, by which the plant's emissions as measured by the CEM, will be multiplied. This equates to the burning of valuable allowances until the next required test or until the utility can schedule another expensive retest.

However, if the CEM reads high by the same amount, there is no offsetting factor less than one by which the plant's emissions are to be multiplied. It should be remembered that the CEM was originally certified using the same reference calibration method. The CEM is the same, the location is the same, and most likely the plant operators are the same. It is quite possible that the CEM is operating just as well as when it was first qualified, but another crew or firm operating the reference calibration equipment has made a series of measurements that indicates a bias in the CEM. It must also be remembered that the time necessary to run a set of reference measurements while maintaining

plant output at a constant level means that in a statistical sense a very small number of measurements constitutes the reference measurement.

Under these circumstances, it is quite possible that an impartial expert observer would conclude that it is as likely that the reference measurements are inaccurate as it is that the CEM is inaccurate, or, because of stratification, that they are both incorrect.

As mentioned previously in these comments, the data which we have received indicates there will be a high incidence of plants failing the bias test of their CEMs and that the instruments will as likely fail by reading high as by reading low.

If the instrumentation is reading too high, it will cause the utility to expend more allowances than necessary, if the reference test was in fact correct. However, if the instrumentation is reading too low, the utility will have to factor up the readings of the CEM

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so that it agrees with the latest reference method measurements or at least until it can schedule a retest. Even if it then passes the bias test, the extra allowances expended in the interim are gone forever.

If the bias test were a double-tailed test, that is to say if a CEM failed the bias test on the high side, the utility would be permited to factor down the CEM readings until the next retest, and then the current for factoring up a low CEM reading might be acceptable. However, as currently proposed, the EPA rules mean in effect that utilities and their customers will be paying for at least some degree of overcompliance with the Clean Air Act Amendments beyond what Congress intended. Under such circumstances, it seems appropriate to question such a one-tailed enforcement measure and ask who will pay for this decision. At the very least, the EPA should explain its rationale for such a proposal and who it believes ultimately will pay the price.

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Based on our review, this one-sided measure could cost one of our electric utilities we regulate in excess of $5 million annually.

In conclusion, given the nature of the utility industry, we fear that it will ultimately be the customers of the electric utilities who who pay the price for Clean Air Act Amendments overcompliance brought about by EPA's proposed rules. Accordingly, we urge the EPA to revise Appendix A to Part 75, particularly paragraphs 7.6.4 and 7.6.5, in order to restore fairness to the proposed rule and adopt a double-tailed test that is not biased against electric utilities and, ultimately, the customers of such utilities.

Thank you.

HEARING OFFICER KERTCHER: Thank you.

Our next speaker will be Mike Neundorfer, Neundorfer, Inc.

MR. MICHAEL NEUNDORFER (Chief Executive Officer, Neundorfer, Inc., Willoughby, Ohio): I am Mike Neundorfer. I am a mechanical

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engineer and president of Neundorfer Inc., in Cleveland, Ohio.

Our small, privately-owned company has been in business since 1958. Our major products and services improve the performance of electrostatic precipitators and energy conversion systems. I am here today to suggest clarifications and minor modifications to the proposed Clean Air Rule.

Our customers have installed as-fired coal sampling systems to facility energy conservation through system and unit heatrate improvement and generation cost reduction. Tests have shown that these systems produce reliable unit sulfur input data in addition to as-fired Btu information.

Our proposed modification to the law will enable our customers to use the sulfur data as a substitute for missing CEM data. This approach is simpler than the proposed rules. It is conservative and preserves the incentive to maintain high CEM availability.

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As-fired coal sampling and analysis can be simply and generally applied as an acceptable back up alternative to a primary CEM in meeting the objectives of the proposed acid rain rule. The purpose of this testimony is to suggest clarifications in system configuration and sampling procedure which can assure that complete and accurate S02 emissions data are obtained using well defined, easy to implement proposals.

Our comments will address:

1. As-fired coal sampling system configuration. An as-fired coal sampler should be installed on each unit feed pipe below the bunker.

2. Sampling procedure. The as-fired sampling procedure should provide a composite

(gross sample) proportional to and representative of the fractional lot of coal actually dired during the sampling period.

3. Composite sample period. The proportional composite sample of fuel fired for

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each 24 hour period of unit operation will meet and exceed missing S02 -- will exceed the S02 data objectives.

4. Missing data substitution. Based on meeting objectives 1, 2 and 3, as-fired sample analysis sulfur data should be directly substituted for missing CEM data. This will eliminate the need for Table C-2 in Appendix C to Part 75.

Neundorfer, Inc., has developed and demonstrated the Coal Lantz, a cutting edge technology for as-fired coal sampling. The Coal Lantz was developed to enable coal-fired utilities to more accurately measure daily unit health rate. The Btu input data used to -- I am sorry. Excuse me. -- accurately measure daily unit Btu input. The Btu input data is used to calculate unit daily heatrate. The daily heatrate data is used for economic dispatch decisions and operational health rate improvement feedback.

These original system design

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objectives are focused on energy conservation and power generation cost reduction. However, tests have shown that this technology also provides reliable as-fired unit sulfur input.

A typical Coal Lantz installation requires that a Coal Lantz sampler be installed on each coal fieldpipe below the bunker and above the feeder. Each sampler is controlled to incrementally sample the coal from its feed pipe within a few minutes of firing. It is important that the coal passing through each pipe is sampled, since coal feedrates can vary very widely from pipe to pipe. This process of proportionally sampling all pipes assures that each increment retrieved represents the corresponding fractional lot of coal fired.

The composite of these increments (gross sample) will therefore truly represent the entire coal lot fired during the sampling period.

Increment spacing is user selectable.

Typically the spacing is automatic and

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proportional to the mass of coal-fired.

The Coal Lantz system has been demonstrated to be reliable, both mechanically and with regard to sample bias. Once per day the samples from each coal pipe sampler are gathered, combined and analyzed. Tests have shown that this sampling technology, combined with good this sampling technology, combined with good analysis, provides reliable as-fired total BTU, total sulfur and total ash input for each sampling period.

We propose that utilities who have installed and implement as-fired coal sampling and analysis as described above, and in accordance with the appropriate ASTM standards, be allowed to directly use as-fired sulfur values (as calculated from the fired mass and percent sulfur from the 24 hour proportional gross sample) as substitute data for S02 compliance. We do not proposed that as-fired coal sampling and analysis be mandated as either a primary or back up technology. However,

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utilities who install and validate as-fired coal sampling and analysis should be allowed to use the results to demonstrate conformance.

Direct substitution of as-fired sulfur values as described above can simplify both Sections 1 and 4 of Appendix C to Part 75. Direct substitutes will not compromise the proposed acid rain rule and CEM objectives of providing complete and accurate emissions data.

The proportional as-fired sample will produce a reliable measurement of unit sulfur input for the sampling period. The sampling period for heatrate measurement is typically 24 hours. The 24 hour sampling period follow sulfur input will certainly meet the objectives and intent of the proposed rule and specifically of Part 75.21 (alternative monitoring systems) and Appendix C to Part 75 (missing data statistically estimating procedures).

The data obtained from proportional as-fired sample analysis can be directly substituted for missing CEM data. The as-fired

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sample analysis can provide the maximum value for total unit sulfur input during the sampling period. This is a conservative value, since sulfur is extracted from the combustion train downstream of the sample and before combustion products reach the stack. Sulfur is removed between the firing and the stack as follows:

1. Some fraction of sulfur is removed from the fuel as pyrites during the pulverization.

2. Some fraction of sulfur is absorbed in bottom ash during combustion and removed from the steam generator as part of the bottom ash removal process.

3. Some fraction of sulfur is extracted from the flue gas by adsorption and absorption by flyash and removed from the economizer hoppers, mechanical collector hoppers, fabric filter hoppers or electrostatic precipitator hoppers.

The amount of sulfur extracted downstream of the sample and before the stack is

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site and condition specific depending on coal chemistry, SO_2 to SO_3 conversion rates, particle characteristics, particulate collection efficiencies, and other factors. However, the amount of sulfur in the effluent as SO_2 is certainly less than the as-fired sulfur.

Therefore, data obtained from analysis of proportional as-fired samples should be allowed as direct substitutes for missing CEM data, and the rule should be written to allow a 24 hour rather than a 6-hour deposit sample.

We propose that units implementing an appropriate coal sampling and analysis be allowed to utilize the sulfur content data to directly substitute for any missing data periods. For short periods of missing data, CEM values for the hours before and after the missing data can be substituted. For longer periods, the total sulfur input as calculated from the analysis of the proportional as-fired sample should be directly substituted. This approach accomplishes the conservatism required

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as an incentive for maintenance of high CEM availability. It accomplishes this with a more economical, simpler methodology.

We appreciate the opportunity to comment on the proposed acid rain rule. We hope our suggestions can be implemented and incorporated into the final rule.

HEARING OFFICER KERTCHER: Thank you very much.

Next on the agenda we had scheduled Bob Koppelmann of Jacksonville Electric Authority, who is not her today. He and Bill Bumpers, who is the person who would have followed him, have ceded their time to the next speaker, who is Bob Bergstrom of Iowa Southern, who I believe will be accompanied by Gary Walling. They will be afforded the time that would have originally been allotted to those three speakers.

Bob Bergstrom?

MR. BOB BERGSTROM (Attorney, Iowa Southern Utilities Company, Centerville, Iowa):
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Good morning, Larry.

My name, for the record, is Bob Bergstrom. I am here representing Iowa Southern. With me today is Gary Walling from Iowa Electric. I have the easy part. Gary is going to do some of the more technically minded things here.

Secondly, mercifully for the audience, and for you, we won't take the full 30 minutes that may be allotted to us. We will tend to be over sooner than that.

These comments presented here today are the product of the combined efforts of three utility groups. We are representing the Upper Midwest Group, the Class of '85 Regulatory Response Group and some of the members of the large public power council. These three groups have found many common areas of concern and formed a coalition representing approximately 30 utilities.

Let us preface our remarks by stating we recognize the difficult task that EPA has to
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create these regulations within a very little time frame. EPA should be applauded for opening up this process in an unprecedented fashion with the Acid Rain Advisory Committee, and I may be somewhat tainted by the fact that I was a member and perhaps still am -- I am not sure where the process stands right now -- of that committee. I believe personally but for the ARAC process, the utility industry would be in total confusion at this stage, but the for the opening up of

that process. I applaud you on that.

EPA further is to be commended for listening to all the conflicting constituencies which are involved in this process. Our coalition tried to recognize the concerns of the competing viewpoints, and we have offered what we believe to be realistically sound compromises that are reasonable in nature.

Since our coalition believes that it is better to work with EPA whenever possible to achieve vital goals at the lowest cost possible, this coalition stands ready to further assist

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EPA in the months ahead as we have in the months gone by.

The intent of the Continuous Emission Monitoring rules, or CEM, is to ensure accuracy by forcing the improvement of the monitoring technology. But the rules must be realistically achievable if the program is to obtain any credibility in the emissions trading markets.

We believe the comments we offer here today are credible, achievable and technology-forcing.

I want to specifically highlight at this time some positive areas of the regulation that the coalition and the EPA should be commended for as well.

Number one, in regard to incentives EPA has really embraced the concept of economic incentives. Heretofore the concept of economic incentives employed by the EPA could be characterized as one of a sliding scale of penalties that you did not receive. In other words, "Here is the stick, and we will beat you

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with it less often."

Now the EPA has seemed to move to the concept of applying the carrot rather than the stick, and we applaud you on that, too. The proposed specification for Relative Accuracy Test Audit, or RATA, frequency to be a function of the level of accuracy obtained is a very good idea. Because of the very early deadlines for CEM installation specified in the legislation, most affected units will order CEMs within the next year or two. Utilities should and are receiving economic incentive or strong signals to improve the performance of the CEM if such an improvement in accuracy -- let me back up: -- a strong economic signal to purchase CEMs that will improve accuracy and result in a reduction in cost from RATA frequency.

Such an economic incentive can be very powerful and we would recommend that EPA maintain and include these incentives wherever possible in the regulatory process.

With proper economic incentives it is

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a win-win situation, as utility ratepayer benefits from a reduced cost to implement a regulatory requirement and the environmental goals of the Acid Rain Program are also improved by the installation of more accurate monitors.

Number two, in regard to missing data, the use of historical data from the data acquisition system for supply of missing data for NOx, flow, and diluent gas, is a very efficient use of reliable data which is already available. The use of actual operating data from the data base is a reliable method of filling missing data routines. This is a positive commonsense approach to filling the so-called missing data gaps with actual data that is not actually missing.

Some use of the 90th percentile is a sufficient penalty to provide the incentive to minimize the length of outages on the CEM system. The use of more punitive values for missing data substitution might distort the emissions reporting to such an extent as to

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jeopardize the confidence in the reporting system. And the trading market.

Number three, with regard to bias, the correction of data with a bias adjustment instead of EPA's earlier proposal, the one that came out in the OMP draft in June of 1990 -- 1991 -- excuse me. To invalidate the data, while not perfect, is a vast improvement from what we saw before. Since the data is not missing, and since the adjustment provides the statistically valid correction for the monitor bias, this proposal provides added confidence to the validity of the reported emissions. As the legislation provides an emission trading market for S02, we certainly agree with EPA that the reporting of S02 should be as accurate as possible and neither under-reporting allowed nor excessive over-reporting required.

Number four, in the preamble of the regulation published on December 3rd EPA made statements which indicated that the EPA was in favor of or was favorable to the installation of

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redundant monitors or backup monitors or perhaps even portable monitors for the collection of data during missing data periods for the primary CEM. We agree that such a back up system should not be mandatory but would be a preferred solution for supplying policing data, because it would provide the most accurate emissions data possible.

However, we can not find such a provision or language for or allowing such redundant backup or portable monitors in the body of the proposed rules. And we strongly recommend that these provisions should be included to allow the the above-mentioned systems and to provide the the most accurate emission data possible.

Number five, in regard to common stacks, the proposed rules include provisions to apportion or partition emissions from affected and non-affected units which share a common stack for sulfur dioxide emissions by the use of parametric monitoring. Since we believe the

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congressional intent was to allow unaffected units to remain outside this legislation, we agree with the EPA proposal.

However, we must raise one concern with regard to this, that the preamble appears to suggest that a similar apportioning of NOx emissions was going to be proposed. Again, in the body of the rules, Section 75.11(a)(3)(iii) appears to contain requirements which conflict specifically with this objective.

We hope that the paragraphs in this section contain typographical ererors, and we recommend that the EPA include provisions to allow parametric apportioning of emissions from unaffected units so they can continue to remain unaffected by Title IV requirements.

Number six, with regard to improving standards of Protocol 1 gas, we are supported and encouraged by EPA's commitment to enhance the quality standard for Protocol 1 gas certification program. Emission measurement data that is supported by calibration gas

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standards of 2 percent or better quality would certainly lend confidence to the quality of the emission data obtained from the CEMs and enhance the trading market.

However, we would encourage EPA to reconsider the 2.5 percent calibration error specification for certification in Appendix A, since such a specification does not allow sufficient error for even the improved quality specified for Protocol 1 gas.

Although we have many areas of agreement with the proposed rules, we are not here today just to applaud you. We have some concerns we want to put before you. There are a number of areas which cause considerable concern to the group. The following issues, which Gary will now address, are major issues which we want to highlight here today, and we believe can be improved upon.

The principal areas of concern are the bias test, requirement for combined flow S02 and the missing data routine for S02. I will now

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introduce Gary Walling from Iowa Electric.

MR. GARY WALLING (Iowa Electric): For the record, my name is Gary Walling, and I am with Iowa Electric.

As Bob mentioned, we have three areas we would like to talk about as major issues to our group, the first being the bias test.

We recognize that EPA is concerned about any potential method for affected units to be able to under-report emissions. Although we believe that the vast majority of emission sources will faithfully comply with their commitments to control emissions and to accurately report those emissions, we can recognize that EPA would want to eliminate opportunities for an unscrupulous owner or operator to manipulate those emissions. We understand and share EPA's desire to promulgate monitoring regulations which will require highly accurate instruments, as demonstrated in the the relative accuracy requirements, and instruments which are free from bias to eliminate the

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under-reporting by any source.

Industry has an obligation to provide compliance, however, in the most cost effective method possible. We do not want to be required to perform excessive numbers of tests which do nothing to improve the performance or the results from the reporting instrument systems. We believe the following is a statistically valid bias test and adjustment system, one that is more efficient and cost effective than the current EPA proposal.

First, when a bias test is used in the certification process with paired data from the CEM and the reference method, the test challenges the bias of the entire system, including the measurement site. After the initial certification or recertification, we should not need to be concerned about any bias associated with the measurement site, since that site does not change. The bias test should only be concerned, then, with any bias which may occur in the system due to changes in the

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operation of the CEM system components or electronics.

We believe that pairing of data from the Protocol 1 gas injected at the flue gas probe, with the data generated by the CEM system, can accurately detect any bias which is introduced after the system has been certified.

Second, the bias test used during certification or recertification is a pass-fail test. Since each CEM must be certified, then passing and passing this bias test is a prerequisite for certification, and a source or owner must have every opportunity to correct a faulty instrument until the desired level of quality is obtained. The EPA may require a source or owner to document the corrective action taken between each attempt to pass the bias test as an assurance that an owner or source wasn't just fishing for a good result. But the source should be allowed to perform as many tests as required to achieve the required level of performance to meet the specification.

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Third, the proposed regulations specify the use of paired data from the Relative Accuracy Test Audit to calculate a bias during the periodic quality assurance/quality control audits. We believe that the use of the paired data from the daily calibration error check is a more effective method to determine bias.

Comparison of the uncorrected daily calibration error with the Protocol 1 gas value will provide an opportunity to determine bias on a more frequent basis -- for example, if you want to calculate it as often as monthly -- and the data adjustment factor could track the contemporaneous conditions of the monitor more closely.

An analysis has been performed by our coalition using calibration error data from 49 units. These results were compared to 75 RATA tests from these same units. The figure is attached to the back of the material you have been handed.

The results demonstrate that the

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calibration error data will provide similar results. That is, if you compare the number of failed bias tests, each method provides a similar amount of pass and fail.

Since the daily calibration error test data is readily available in the data acquisition system, the use of this data for the bias adjustment would be much more efficient and more accurate as this data is traceable to the NIST Reference Materials.

We believe the accuracy in the reported emissions which would be maintained by the use of this 2 percent quality traceable to NIST Gas Standards would support the goal of establishing confidence in the allowance trading markets.

Also, the EPA has acknowledged that the results of the collaborative tests indicate that the the reference methods are only capable of achieving accuracies in the range of plus or minus 8 to 13.2 percent of the mean value.

Although we encourage EPA to undertake

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efforts to improve the reference methods in the long-run, in the proposed regulations we would recommend EPA revise the bias and the data correction procedures to utilize the quality control daily calibration error data.

Finally, if the relative accuracy of the CEM system is better than 5 percent, the data should not require a bias adjustment. Since the measurement of any parameter involves some random error, we believe that for highly accurate systems these random errors in measurement will not cause a significant amount of under-reporting of data. We recommend EPA specify some level of relative accuracy for extremely accurate systems for which no bias adjustment is required.

The second issue we want to talk about is the requirements for the combined S02-flow. There is no need to establish a relative accuracy for the combined S02 and flow instrumentation. The accuracy of each instrument is demonstrated with certification

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testing and periodic quality assurance/quality control functions to assure the reliable and accurate operation of each instrument. It is required to merely perform simple mathematical calculations to derive the actual emissions of S02 utilizing output from these instruments.

EPA must recognize that each of these instruments operates separately from the other, so that the accuracy and reliability of each instrument is not directly related. Combining the requirement for accuracy of both instruments imposes a redundant and potentially conflicting accuracy requirement which may not be possible to achieve simultaneously with individual accuracy and bias tests of each separate instrument.

This is particularly true since the EPA reference methods do not contain a combined relative accuracy procedure.

The separate reference method procedures, when merely combined mathematically, do not provide a sufficiently accurate result to

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support the EPA specification.

The last issue I would like to address is missing data for sulfur oxide emissions.

The preamble discusses the need for accuracy in reporting missing data, and we agree there should not be an opportunity to under-report emissions, nor for an operator to "game" the system. However, a missing data substitution routine should not be required which adulterates the quality of the emissions database through overly conservative data substitution routines. Substitution of inflated emissions data will not serve to achieve EPA's goal of establishing the market's confidence in emissions trading.

When discussing the installation of duplicate certified CEMs, the preamble states that this alternative was rejected by EPA due to the high cost of this alternative if this alternative was mandated. We calculated our costs for the proposed method of correlating the fuel sulfur to the database of emissions

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accumulated by the CEM. The cost of the current EPA method far exceeds the cost of a redundant CEM. Within the UMG the cost to install a coal sampling device which will meet the specification of the EPA's proposal range from a half million to one million dollars per plant.

We believe the benefit gained, if any, by the EPA's proposal cannot justify the cost. To our knowledge, there are no economical automated sampling systems commercially available to sample coal at the location specified in the regulation. The only alternative for some of our plants would be to employ manual methods to accumulate and process coal samples.

A sample method of substitution of the highest value, or some variation, involving the average of the highest five or the 90th percentile, et cetera, of the S02 accumulated in the CEM data base would be the least expensive. This is particularly true for units with coal sources which do not vary significantly in

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sulfur content.

Even for units which have variable fuel sources, the cost for reporting artificially high emissions would be only the cost of the excess emissions credits consumed during the missing data period.

The preamble suggests that the EPA is encouraging the use of backup portable CEMs as replacement for a malfunctioning primary system. However, the actual rules do not provide for substitution of data from another or portable CEM. The only method specified in Appendix C for units which do not have S02 emissions controls equipment is the use of the data from the coal sampling/correlation method.

Therefore, we recommend that the EPA allow data from redundant or portable or shared CEMs, that is shared with monitors on adjacent stacks, or adopt substitute data from the CEM data base, which is based on some variation of the maximum values over some look-back period. The variation employed could be chosen which is

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most representative of the historical emissions from the unit.

But even if the values were conservative over-reporting emissions, such values would be preferable to the coal sampling method. The cost of the lost credits would represent the incentives for the owner to improve the reliability of the CEM.

I thank you for the opportunity to offer these comments. The Coalition respectfully submits the foregoing and requests the EPA consider these when drafting the final regulations.

HEARING OFFICER KERTCHER: Thank you.

I have two questions. The data to which you referred in your testimony, has that been submitted for our review, as well?

MR. WALLING: I don't believe so. It would be available, though. It was just assembled here during the last week. I don't believe we have had time to submit it.

HEARING OFFICER KERTCHER: Were you

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expecting to send it during the public comment period?

MR. WALLING: Yes.

HEARING OFFICER KERTCHER: The second and final question is the procedure that you are recommending for the substitution of daily calibration data in terms of the calculation itself -- is that in the submitted data?

MR. WALLING: The calculation we would proposes is virtually identical to the one that is in the Appendix now. The difference is the pairs of data would be the CEM value and the Protocol 1 gas value. They would be the two pairs of data that you would use in the calculation. Otherwise, it would be the same.

HEARING OFFICER KERTCHER: With a daily adjustment, or --

MR. WALLING: You take the unadjusted, the uncorrected, daily value and the bottle gas value, and that forms a pair of data. Over 30 days you would then have 30 pairs of data. So if you want to do it monthly, you would do a

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single calculation for monthly --

HEARING OFFICER KERTCHER: So, it would be month by month, rather than by RATA.

MR. WALLING: That's correct. And, in fact, I guess we propose it could be any time period. You would just need enough days to make a large enough population of compared data. Monthly was proposed because it was easier.

HEARING OFFICER KERTCHER: Thank you.

Next is Art Smith, Northern Indiana Public Service Company.

MR. ARTHUR E. SMITH, JR. (Environmental Counsel and Manager of Environmental Affairs, Northern Indiana Public Service Company-Northern Indiana, Hammond, Indiana): Good morning. My name is Arthur Smith. I am the Environmental Counsel and Manager of Environmental Affairs for the Northern Indiana Public Service Company of Northern Indiana.

Also here with me today is John Ross, who is the Supervisor of Environmental Planning

at Northern Indiana.

Northern Indianas is an electric and gas utility, serving approximately the northern one third of Indiana. We have three coal-fired generating units impacted by the rules during Phase I, units 7 and 8 at the Bailly Station and Unit 12 at the Michigan City Station.

Northern Indiana is a member utility of the Utility Air Regulatory Group that submitted testimony at the January 6, 1992 hearing in Washington, D. C.

Northern Indiana would like to take this opportunity to provide additional general comments on the proposed rules and highlight specific areas of which we are particularly concerned. Northern Indiana will follow with additional and more detailed written comments on the proposed rules during the comment period.

My comments will focus on a few areas: Phase I extensions, reduced utilization, continuous emission monitoring, and then the allowance transfer deadline.

I first would like to address Phase I extensions. At Northern Indiana's Bailly Generating Station our contractor is currently constructing a flue gas desulfurization unit or scrubber which will serve two units, units 7 and 8. The installation of the scrubber is scheduled for completion in July of this year, well before the Phase I compliance deadline, and may be the country's first Phase I unit to do so.

Congress both intended that the requirements of the Clean Air Act encourage the installation of continuous technological controls designed to achieve at least a 90 percent reduction during Phase I and to assure that controls be installed in the most expeditious manner possible.

Northern Indiana realized such and acted early in anticipation of the acid rain rules.

Northern Indiana is primarily concerned that the proposed rules regarding

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Phase I extension plans reflect that congressional intent.

The Phase I extension provisions in the Clean Air Act Amendments were designed to not only allow a utility extra time for installation ever a control technology, while not having to purchase extra allowances to cover the shortfall, but also reward utilities that installed the control device early. These extra allowances could potentially be banked for future use or sold to offset the costs of early installation and operation of the control device. EPA acknowledges this in the proposed rules. Section 72.42(b)(1)(ii)(A) states that a "unit for which an extension is sought will install on or after November 15, 1990 but not later than December 31, 1996, a qualifying Phase I technology."

Northern Indiana generally supports EPA's proposal related to extension allowances, but would like EPA to further clarify the congressional intent. Since the word "install"

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is not defined in the act and the use in this section implies the following definition, we suggest that EPA clarify the word "install" is defined as "commenced commercial operation of a qualifying Phase I technology."

In addition, Northern Indiana insists that EPA not adopt the alternative interpretation of the statutory language of

Section 404(d)(4)(A)and (B) mentioned at 56 Federal Register 63017.

Although the application of the alternative interpretation is unclear, it appears that the strict application of this alternative interpretation would yield the award of a negative number of extension allowances.

Clearly, the intent of Congress was to project a potential uncontrolled emissions estimate for determining a positive extension allowance availability, thereby rewarding the early compliance.

Section 404(d) directs the EPA to review and take final action on each proposal in

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order of receipt. Northern Indiana is concerned about a system which would determine receipt in terms of minutes, seconds, or even fractions of seconds. We have believe that the intent of this section was that the order of receipt of a proposal could be measured or determined by the day in which it was delivered or received.

Northern Indiana believes that the EPA should specify a date on which applications can first be submitted. Should the Phase I allowance reserve be oversubscribed on that date or any future date, the reserve allowances remaining would be apportioned according to a system that would encourage the earliest possible operation of the the compliant technology units.

I would next like to address reduced utilization.

Northern Indiana believes that the general approach outlined in the proposed rules provides for a fair and workable, although somewhat complex approach to dealing with

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reduced utilization at Phase I plants. We understand that protection is required to assure that Phase I S02 reduction goals be achieved and will not be compromiseed by the unplanned shifting of generation from Phase I units to other generating units.

We support the idea that should a Phase I unit experience an unplanned reduced utilization, that several tests be available to rebut the presumption that the reason was due to a lack of consideration in a compliance plan.

Northern Indiana supports the

additional measure of an aggregate systemwide Phase I unit test. The system test should take into consideration the aggregate utilization of all Phase I units in the North American Electric Reliability Council region. Should the region Phase I unit utilization be equal to or greater than the unit's aggregate baseline, then the EPA could be assured that the S02 reduction goals are met and that compliance planning and allowance surrender requirements are not

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necessary.

Next I would like to address the monitoring certification of CEM.

The monitoring certification provision states in Section 75.23(b)(1) that a 30-day notice is required prior to certification or recertification testing. Northern Indiana believes that a 30-day notice is warranted for a certification determination, but we feel this is not necessary for the recertification testing. A 30-day notice requirement for recertification could result in the needless loss of additional data while waiting for the period to pass. As a result, we feel a recertification test should be allowed in as short a period as can be agreed upon by the utility and regulatory agency.

Additionally, Section 85.18(a)(3) states that EPA has 120 days to act on a request for recertification. Northern Indiana believes that this period is excessive and that an approval or disapproval can and should be made within a 30-day period. The 4-month waiting

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period could require the needless and costly use of an alternate monitoring system.

Next I would like to address CEM bias testing.

Northern Indiana believes that EPA's current proposal for monitor bias testing using relative accuracy test audit data is not an appropriate method to determine bias from which to apply a correction factor. The RATA is conducted over a very short time period and does not give a statistically representative picture of long-term monitor performance.

Consequently, the RATA results should not be used to adjust monitoring data for the 6-month to 12-month period between testing. Instead, we support the use of information collected during the daily calibration error test to adjust the CEM data. This would require daily retroactive adjustment of emissions data to correct any inaccuracies that are not automatically adjusted for during the daily monitor calibration.

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We believe this procedure, when combined with daily monitor calibration and other quality control requirements is the only reasonable way of reducing the possibility of biased data.

As some of the other commenters have commented on, I would also like to comment on the continuous emission monitoring-missing data.

Northern Indiana realizes that one hundred percent data retrieval is not always possible with CEMs and is concerned how the missing data values will be filled in. We support EPA's posture, stated in the proposed rules, against the use of historical maximum values which will result in outlier values not reflecting actual operating conditions.

We believe that a realistic unbiased approach to filling in periods of missing data should utilize the use of an hour before/hour after procedure. This procedure, when used with reasonable limit of its use, according to the

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duration of missing data, should result in a level of accuracy which comes closest to values that would have resulted from one hundred percent data capture.

Even though EPA has concluded that extremely high monitor availability through a biased estimation technique overrides the statutory goals of accurate annual emissions data, we encourage EPA to adopt a reasonable percentile approach without the fuel sampling and analysis procedures. This additional procedure would be very expensive to implement and would add little to a reasonable percentile approach.

Consequently, we support the proposed 90th percentile approach without the fuel sampling and analysis procedure, which would be most feasible for those sources with the less than 95 percent data capture.

Finally, I would like to address

allowance transfer deadline.

We commend the EPA for increasing the

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allowance transfer deadline from January 15 of the year, as contained in the draft, to the now proposed 30 days. However, Northern Indiana continues to share the view of many others that a period of no less than 45 days is needed. Such a period gives utilities and other market participants a reasonable period of time that Congress had intended to complete allowance trades. Extending this period to 45 days will not affect achieving the emissions reduction goals after the statute.

I thank you for your attention. I appreciate your coming out to Chicago.

HEARING OFFICER KERTCHER: Thank you.

Is Paul Reynolds, Hoosier Energy, in the audience?

Our next speaker will be Tom Albertson, Iowa-Illinois Gas and Electric Company.

MR. TOM ALBERTSON (Superintendent, Environmental Services Division, Iowa-Illinois Gas and Electric Company, Davenport, Iowa):

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Good morning. My name is Tom Albertson, and I work for the Iowa-Illinois Gas and Electric Company, an investor-owned utility headquartered in Davenport, Iowa. I am the Superintendent, Environmental Services Division at Iowa-Illinois.

I appreciate this opportunity to discuss the EPA's proposed Clean Air Act regulations at this public hearing. Today I would like to focus my remarks on the Agency's proposed Part 72 permit regulations. Specifically I would like to comment on the Agency's use of definitions in determining applicability for existing Phase II affected units as applied to Iowa-Illinois in proposed Appendix B to Part 72.

Proposed Appendix B to Part 72 lists those units which the Agency has at least preliminarily proposed as existing Phase II affected units. Contained within this listing are Iowa-Illinois Gas and Electric Company's Riverside Generating Station boilers numbers 6,

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7 and 8. It is Iowa-Illinois' position these

units are not existing Phase II affected units, based on language contained in the Clean Air Act Amendments legislation and should not be included within the proposed Appendix B of Part 72.

I recognize the Agency's request to reserve comment on the inclusion of specific units listed in proposed appendix B until the rulemaking on existing Phase II affected units is proposed. We do intend to monitor that rulemaking and provide written comments if appropriate.

However, the concerns I have today center on integral definitions contained in Part 72 that are used to determine applicability under the act. Since these definitions appear to be the primary basis for listing sources in Appendix B, the use of interpretation of these definitions as discussed in Part 72 must be addressed during this comment period.

Before I elaborate further on why

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these boilers do not meet the criteria for inclusion under Phase II and therefore should not be included in Appendix B, it is necessary to briefly review the past and present operation of the Riverside Generating Station.

This facility consists of four boilers. The largest of these is an 860,000 pounds per hour unit installed in 1961 and is a Phase I affected unit. The steam produced by this boiler serves a 136 megawatt generator.

The other three boilers in combination are somewhat smaller than the Phase I unit and were installed during the 1940s. These three boilers are connected into a headered system that jointly serves a 5 megawatt generator and supplies steam to a large industrial customer.

Prior to 1988 this headered system also served a 46 megawatt generator. This turbine was retired in 1988. The regulatory applicability of these smaller units is determined by reviewing the definitions of "existing unit" and the exclusion provided for

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cogeneration units under the "utility unit" definition.

In Section 402(8) of the act, Congress defines an "existing unit" with respect to the applicability to Title IV of the act. This section also provides that:

"For the purpose of this title, existing units shall not include simple combustion turbines or units which serve a generator with a nameplate capacity of 25 megawatts or less."

In the definition of "existing unit" proposed in Part 72, the Agency modified the language set forth in the act and limited the scope of this exclusion by adding the requirement that the unit is exempt if it only serves a generator with a nameplate capacity of 25 megawatts or less. Adding this requirement to the definition narrows the applicability of the "existing unit" exclusion previously provided by Congress for headered systems that could generate steam and electricity, such that

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Riverside Station boilers numbers 6, 7 and 8 would potentially become affected units under Phase II.

Moving from this expanded definition to the proposed applicability Section 72.7(b)(2), the Agency further narrows the "existing unit" exclusion by noting that a unit is not subject to acid rain permitting under this part if the existing unit did not and does not currently serve a generator with a nameplate capacity of greater than 25 megawatts.

Adding the proposed regulatory language "did not" is not supported in the legislation. The legislative language for this definition exclusion in the act is postulated in the present tense, speaking to units "which serve" a generator and can only be interpreted as of the time of enactment.

Congress correctly concluded that it wasn't economical to impose acid rain regulation on very small units in light of the marginal environmental benefit received. By proposing to

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brush aside this exclusion, the Agency has broadened the scope of affected units beyond what Congress intended.

Our previous meeting and discussion with key Agency personnel on this matter indicated the Agency was interpreting the phrase "which serve" to cover the 1985 or 1985-1987 baseline period. This interpretation has no support in the legislative language.

Based on these comments, the Agency must return the "existing unit" exclusion back to its congressional format, revise proposed Section 72.7(b)(2) accordingly, and remove Riverside Station boilers 6, 7 and 8 from Appendix B.

Since Riverside Station boilers 6, 7 and 8 are cogeneration units, I also wish to speak about the the definition of "utility unit" under Section 402(17)(C) of the act. This definition provides a regulatory exemption under Title IV for a unit that cogenerates steam and electric unless "the unit is constructed for the

purpose of supplying or commences construction after the date of enactment of this title, and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale."

Based on this definition, it is Iowa-Illinois' position that the small boilers at Riverside would also be excluded under this provision from being existing Phase II affected units due to their cogeneration operation.

The legislative exclusion uses the present tense by saying "unless the unit is constructed," indicating a cogeneration unit in existence on the date of enactment of the act is exempt from acid rain permitting.

We have discussed with Agency personnel how the Riverside situation is impacted by this cogeneration exemption. It was suggested by EPA that the determination of the applicability to these small boilers as affected units would depend upon the intent of their

installation in the 1940s. Iowa-Illinois disagrees with this position. It is not supported by legislative language. It is also not practical to expect that the Agency can consistently implement this provision on unit applicability, particularly when confronted with situations like ours, where intention would have to be determined from actions taken almost 50 years ago.

In summary, Iowa-Illinois believes Riverside Station boilers numbers 6, 7 and 8 are not affected Phase II units. We urge the Agency to be especially mindful of congressional definitions contained in the act during its numerous rulemakings, so that congressional intent is accurately reflected in the final regulations promulgated.

Thank you.

HEARING OFFICER KERTCHER: Thank you.

Our next speaker will be Tom Coleman, Chicago Board of Trade.

MR. MICHAEL WALSH (Advisory Economist,

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Chicago Board of Trade, Chicago, Illinois): Mr. Coleman was not available to make a comment today, so he asked me to speak on his behalf. Mr. Coleman is the Vice President and Director for Economic Analysis and Planning at the Chicago Board of Trade. My name is Mike Walsh. I am an Advisory Economist at the Chicago Board of Trade, in his department.

My comments address the emission allowance market provisions in the acid rain section of the Clean Air Act Amendments. My comments are sort of a broader perspective. In doing so, I would like to step back and register a vote of confidence and explain that vote of confidence and support for the market approach that is used in Title IV. I hope that these comments can remind us all of the importance of the detailed efforts you are all undertaking.

I would also like to explain the Board of Trade's plans for participating in this market.

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The Chicago Board of Trade applauds the EPA for its extensive efforts to make this innovative program a reality. Congress and the administration did a great deal of work to pass the legislation. The emission allowance market program is a creative step to improve regulatory efficiency. The decision to use a flexible market oriented approach to reducing sulfur dioxide emissions makes fundamental economic sense. If it succeeds, it will significantly lower the cost of reducing emissions.

This means electric rates will be lower, which saves consumers money and helps industrial competitiveness.

The Chicago Board of Trade is the world's oldest and largest futures exchange. We currently support open outcry market trading in

36 futures and options contracts based on agricultural commodities and financial instruments. The Chicago Board of Trade will offer a mechanism for trading sulfur dioxide emission allowances, and we have proposed to

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offer a futures contracts on emission allowances. These futures contracts will give utilities and others a tool for managing the price risk for emission allowances and thus will help improve utility planning and cost control.

In addition, the Chicago Board of Trade will propose to be designated as the official administrator of the annual emission allowance auctions and direct sales.

While we are not experts on the electric utility industry, we do know markets, and we are working with firms in the industry and its regulators to make sure the services we offer meet their needs.

The importance of our efforts is highlighted by comments made to our regulator by a major midwestern utility. They said, "The Chicago Board of Trade's proposal will facilitate the development of a nationwide allowance trading market, which should help to ensure that emission allowances can be freely traded and that the robust allowance trading

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market envisioned by Congress in the amendment remains viable. A national futures market will allow trading and discovery of allowance prices and give utilities a way to manage risk."

They added: "The flexibility for compliance options provided in the amendment will not be realized without a fair and efficient way to value and trade allowances. CBOT's proposal provides such a mechanism.

We believe our experience in running active, fair and open markets will help make the emission allowance market program a success. We also hope the success of this program leads to adoption of other market based environmental regulations.

The emission allowance market program tries to remedy the well-known problems inherent in command and control regulation. Command and control environmental regulations generally provide no incentives to those who can efficiently make extra pollution reductions.

They do not recognize or take advantage of the

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fact that different companies face different compliance costs, and they do not focus on the big picture -- cutting overall emissions at the minimum overall cost to society.

Command and control regulations and command control economies are inflexible. They don't encourage ingenuity among individual businesses, and they require costly government involvement in numerous business decisions.

We seem to be in an era when the value of free markets and market mechanisms are becoming more fully appreciated. For example, consider the People's Republic of China and the republics of the former Soviet Union. In those cases a conscious decision was made by government officials to move from command and control toward free markets.

At the Chicago Board of Trade we are particularly aware of the worldwide growth of organized futures markets, which may be the purest form of free markets. In the 1980s futures markets have not only been established

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in the spheres of developed market economies, such as London and Tokyo, often with the help from the Chicago Board of Trade, but also in developing economies such as China and Hungary.

Given these trends, it is entirely appropriate for Congress and the EPA to bring the strength of market forces to bear on solving environmental problems.

The emission allowance program uses market incentives and sales to business. "We will let you earn rewards in the marketplace if you can cut emissions more efficiently."

This is the same signal given to producers of other products in a market economy. It also introduces flexibility that encourages those utilities that are most efficient at cutting emissions to make more of the emission reductions.

This feature means less resources are used up in cutting emissions, and the costs paid by electric consumers can be and are minimized.

To summarize, the flexible

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market-oriented approach contained in the sulfur dioxide emission allowance market program is exactly the right kind of step needed to help lower the costs of improving environmental quality. Minimizing the cost of cleaning up the environment means we get more environmental quality per dollar spent. It also means society may be more willing to undertake future efforts to improve the environment if we can do so efficiently.

The CBOT supports the EPA in its effort to make the emission allowance market work. The program makes economic sense and can save consumers and industry money. We hope electric utilities and their regulators can work together to adopt rules that help make this market a success.

Thank you forgiving me the opportunity to present these comments.

HEARING OFFICER KERTCHER: Thank you.

Our next speaker is N. N. Dharmarajan, of Central and Southwest Services.

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MR. N. N. DHARMARAJAN (Principal Engineer-Environmental, Central & Southwest Services, Inc., Dallas, Texas): My name is Dharmarajan, and I am the principal environmental engineer for Central and Southwest Services, Inc., Dallas, Texas.

I appreciate the opportunity to present at today's hearing the preliminary views of the Central & Southwest system on the proposed continuous emissions monitoring system rules, Part 75.

I will attempt to review areas of major concern to us and offer suggestions to sharpen the regulations so as to permit easy implementation of the regulations by utilities.

As to background, the Central and Southwest System serves four states -- that is, Arkansas, Louisiana, Oklahoma and Texas -- and includes four electric operating subsidiaries. The system serves an estimated population of 4.2 million people and has an installed capacity which approximates 13,500 megawatts.

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The generation mix includes 43 percent natural gas, 52 percent coal and lignite and 5 percent nuclear. The C&SW plants are Phase II affected units under the 1990 Clean Air Act Amendments. These plants fall into two categories:

Solid fuel plants, and we have a total of 9 of these, which range in size from 450 to 725 megawatts. And two coal and lignite units are scrubbed.

Then we have natural gas plants, which total about 56, ranging in size from 25 megawatts to 470 megawatts. Some of these units have oil backup capability, primarily to augment electric production in the event of cold weather related gas curtailments.

Forty-five of these 56 units have been in service for over twenty years, with 8 other units ranging in service from 15 to 20 years.

Thirty-five of these 56 units are operating at a capacity factor of less than 20 percent, and over 50 percent of these units have

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not operated for the past three to four years.

Approximately 11 of the remaining units can be classified as medium capacity, operating in the range of 20 to 40 percent.

Before I delve into today's hearing's topics, I would like to use this forum to recognize the EPA's responsiveness to some of the comments we made to the draft rule of last summer. In particular we commend the following EPA actions:

Amending or deleting certain requirements based on a review of the need, cost, hardship and experience factors that were brought to its attention.

Scaling back on the requirements for and introducing incentive-based rules for redundant and costly activities, such as stack testing frequencies.

Allowing for use of tenable methods for accounting of S02 commission emissions in gas-fired units when burning oil without the need for costly stack monitors and without the

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need for costly stack modifications.

Using a phased and graduated relative accuracy regimen for the newly required gas flow monitor component in the emissions determinations.

And deleting the opacity monitoring downstream of a wet scrubbed unit.

We nonetheless feel obligated to bring to the EPA's attention certain other changes that need consideration.

Adopting the suggested changes will be a win-win situation for both the EPA and the regulated community.

I have a slate of issues, both technical and implementation issues, to share with you. I will speak to as many as time will permit, and some of these items may have been already pursued this morning by other speakers.

The first issue of interest to us is the bias determination requirement. The proposed regulations -- they intend to make use of the relative accuracy test audit, or RATA,

data to make the the statistical CEMs instrument bias determinations. If the results indicate a low bias, then the CEMs data emissions data will be adjusted upward until such time as the bias is corrected. High bias to the emissions data will not be tended to.

As stated in our comments to the EPA draft proposed rules last summer, we continue to question the bias requirements and the bias determination methodology. We wish to present our reasonings one more time here and urge the EPA to reconsider its position in the final rules.

1. Performance of a monitor cannot be enhanced beyond its capabilities, even with the best system installed and maintenance practices.

The RATA process, which compares contemporaneously the CEMs performance against a reference method that uses separate equipment and personnel will introduce errors and variability. The source of errors with the

reference methods will be in the sampling, analysis and data reduction steps. Unfortunately the CEMs will have to absorb the reference method errors.

3. The RATA process also entails challenging the reference method instrument and the CEMs with the process flue gas. Unfortunately, the process flue gas stream may have some variability which could magnify the statistically determined bias number.

4. The RATA process, and, hence, the bias determination, is accomplished for a short time capsule, maybe a or two. With the uncertainty associated with the reference method

procedures, the results of such a comparison may be unduly punitive.

5. The reference methods entailing use of instrumental techniques in the RATA test are permitted to use protocol gases in establishing and adjusting bias in these instruments.

In reviewing the above facts, there

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are compelling technical, logistical and precedential reasons for the EPA to allow the daily calibration process, using protocol gas in determining and adjusting CEMs bias, if needed.

The daily calibration error method, without external intervention, would be a natural extension to account for CEMs instrument bias determination without other factors, such as sampling errors, reference method inaccuracies, unduly penalizing the CEMs.

The second issue I would now like to address is the relative accuracy limits for combined flow/pollutant monitor.

The proposed rules contemplate establishing a combined S02 flow system relative accuracy standard of 10 percent effective January 1 in the year 2000. The corresponding individual relative accuracy standards are stated to be 10 percent for flow monitors and 10 percent for S02.

Our analysis of simulated relative accuracy test data for both S02 and flow points

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up a serious discrepancy with the proposed combined S02-flow system relative accuracy criteria. The the table summarizes the problem. I have attached a table which presents a summary of what we have found.

The cases in the table illustrate the conflicting nature of the proposed requirements. It can be surmised that the combined standard called for in the proposed regulation will be self defeating, result in loss of allowances, and will lead to untold expenses associated with repeated testing to chase an unattainable number.

We suggest the EPA drop the combined criteria, which is nothing more than a statistical computation with no real advance to the accuracy of the emissions. What is important is the individual monitor relative accuracy standards, which are already stringent.

Issue No. 3 pertains to missing data estimating methodology for S02 monitors. The

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proposed regulation includes a requirement for establishing coal fuel sulfur content ranges based on fuel analysis every six hours, which is to be correlated to hourly CEMs values. In the event of missing data for a given hour, depending upon the availability of the monitor, the operator would identify the sulfur content range for the coal-fired during that hour and select the 90th percentile value from the appropriate range to fill in the missing S02 value.

We submit this requirement is unnecessary and misplaced, especially in the context of its use as a procedure for filling in missing data. We see this process as being unduly burdensome and outrageously expensive.

To appreciate the complexity of what is required, we would like to review the details of the steps involved.

The regulations specify use of ASTM protocols in the sampling and analysis of the coal. The sampling component would entail use

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of complex mechanical samplers and collection of 35 samples of 5 pounds each for every 1000 tons of coal fed to the boiler. For one of our lignite units this translates into approximately one and one quarter tons per day of sample. The cost of the sampling equipment, which is several hundred thousand, manpower involved in maintenance and collection of the samples, analytical equipment involved and its operation and maintenance costs, do not warrant the use of this proposed method.

We recommend the EPA drop the coal sampling and analysis requirement for the missing data correlation. Use of the 90th percentile historical number should be a severe-enough penalty and an incentive for higher monitor availability.

Issue No. 4 -- analytical information turnaround time for gas units.

Appendix D places a requirement for oil sample analysis to be made available the day after the sample is composited or taken. We

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feel this requirement is unreasonable and unnecessary.

Oil samples are oftentimes sent to commercial labs for analysis. The labs also have a token system for scheduling their workload and do not commit to overnight availability of information. Weather-related information can also impact information turnaround.

Considering the "de minimis" nature of the emissions from gas units when burning oil, we recommend that the EPA define a more practical time frame, such as a week, for information turnaround.

Issue 5 is opacity monitoring for gas units in peaking service.

The preamble Section 56, Federal Register 63086, exempts from opacity monitoring gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the year, when oil is used as the backup fuel. We support the exemption.

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We, are however, concerned about instances where the gas-fired unit in peaking service does not meet the literal definition of "no less than 90 percent gas input on an annual heat input basis."

In a peaking type gas unit which does not operate in summer months but is called upon in winter for a limited period, gas curtailment could result in oil firing. Since the unit has not operated for months and even some quarters, this short period of oil firing could transgress the 90 percent gas heat input criteria.

The important consideration would be that these units have effectively operated a minimal amount of time.

We would suggest that the EPA extend the opacity monitoring exemption to all gas-fired units, irrespective of their annual gas heat input.

Issue 6 is NOx monitoring exemption for low capacity factor gas units.

There are a whole slue of issues there

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suggesting why we should be exempted from having to monitor. Since there is less than one minute of time left, I will just hit the key points here.

Point 1: These low capacity factor units operated with minimal emissions compared to a base loaded unit. As demonstrated in our plant statistics, over 50 percent of our peaking gas plants have not operated for several years.

Point 2: The QA/QC plans in Appendix B will require daily calibration checks, quarterly assessments and RATA tests.

Peaking service plants do not operate for several months or even several quarters. Expenses associated with these daily checks, firing up a unit to perform the NOx RATA, administrative burdens for both the utility and the EPA, would far out weigh the efforts to monitor insignificant emissions from these units.

The EPA can be provided accurate accounting of the annual average NOx rates using

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one of two reliable approaches. One method is through the use of AP-42 factors. A second method is through a combination of the average load profile for a year in conjunction with a load-NOx curve.

We strongly encourage the EPA to grant exemption to peaking units based on the above considerations. For establishing a definition of a peaking gas unit, the EPA may wish to equate the hours of operation of an exempt 25 megawatt base loaded coal unit as a standard. These coal units are exempted from the monitoring provisions.

Do I have time for one more?

HEARING OFFICER KERTCHER: Go ahead.

MR. DHARMARAJAN: Thank you.

Issue 7 pertains to the retiring unit provision.

The regulations include a provision to exempt affected units from the monitoring provision if a certified commitment is made to permanently retire the unit before January 1,

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1995. In the context of a Phase II affected utility system such as ours, we would like the EPA to extend the retirement deadline to January 1, 2000.

Phase II affected units, especially the gas/oil units, have no Title IV NOx emission rates or allowances.

Eighty percent of our affected gas units, which totals 45 units, would have been in service greater than 30 years by the year 2000. Since these gas units, especially as presently proposed, require NOx and diluent monitoring, the EPA should consider affording the retirement opportunity provisions until 2000 and not require CEMs.

As I mentioned earlier, other accurate means are available to provide the necessary accounting in the interim period.

One last issue: Recertification standard. The proposed rules require a 30-day notification prior to certification and recertification. For purposes of

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recertification, this requirement could mean loss of additional data while the unit is awaiting EPA certification. We recommend that the EPA provide the utility some flexibility by not requiring notice of recertification.

The EPA should also consider developing a list of routine maintenance activities, such as changing probes, replacing lamps, computer boards, et cetera, which will not trigger recertification.

In conclusion, time is not going to permit me to share several other implementation type issues. These will be submitted in detail by the February deadline. We thank you for your time and hope that our comments and recommendations will be of use in your final rulemaking process. We want to work with you in developing a set of regulations that can be easily administered and implemented.

Thank you.

HEARING OFFICER KERTCHER: Thank you.

At this time I am aware of only one

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more speaker. That person is Phil O'Connor of Palmer Bellevue Corporation.

I would like anyone else in the audience that has not presented comments that would like to do so to present me with your name and affiliation, so that I can call you up. Otherwise, the hearing will be adjourned after Mr. O'Connor makes his presentation.

MR. PHILIP R. O'CONNOR (Chief Executive Officer, Palmer Bellevue Corp., Chicago, Illinois): This will be very brief.

My name is Philip R. O'Connor. I am chief executive officer of Palmer Bellevue Corporation of Chicago. I appear today to provide comment on these proposed rules. I should note my comments are really from the vantage point of I have enjoyed serving as chairman of the Allowance Trading and Tracking Subcommittee of ARAC.

I will largely confine my brief comments to just a few areas, where I take some exception to the proposed rules or where

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U.S. EPA has specifically asked for comment on options.

As a general matter, any lack of attention I might give to any point in my comments ought to be taken as a statement of approval for everything else that I don't take exception to.

My opinion is EPA has done an absolutely outstanding job in preparing these rules for what is really a rather complicated process.

I might send some further written comments in on another point if I discover any point of difference that I have with the rules.

With respect to the designated representative first, I think U.S. EPA is absolutely correct in rejecting the suggestion that it require unanimity in the designation of the representative in the case of multi-owner units. In fact, minority interests are perfectly well protected in the law by reason of the requirement that all owners share and share

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alike in the proceeds or other economic benefit of the use or transfer of allowances. In other words, if anybody does something, a minority owner is in there on an equal basis, and that ought to be sufficient to deter any kind of misbehavior.

In addition, a unanimity requirement would create the possibility that for isolated incidents, in which current disputes among owners have already -- where they already exist, a minority partner would really have an entirely new weapon in the disagreement, and that would constitute really an interference by the U.S. EPA in existing commercial relationships.

With respect to the telephone queue, I

would only say there is some potential there for gaining -- there is always some potential for some kind of snafu. My own opinion is it would be preferable for EPA to adopt an order of receipt approach to Phase I extensions, which simply relied on each 24 hour day as a single time period in which all filers on a day would

be treated on an equal basis. That is only pro rata to the extent that on any particular day the allowances for the extensions would have run out.

On the other hand, I would note that if EPA does stick with the telephone queue, the option there for the utilities in question is to engage in a voluntary pool, that has been suggested. So, there is a fallback to that. Nevertheless, I think it would be preferable to have a 24-hour period.

Just several points on the allowance tracking system. EPA has made the correct choice in choosing to immediately record transfers of future year allowances rather than waiting for a final transfer recordation pending the end of the year in question. The reasoning of the rule is sound. Immediate recordation should lend support to a more certain and therefore a more liquid and efficient market in allowances. The speaker from the Board of Trade, I think, in making the point about the

operation of a market, would probably agree with that point.

Secondly, U. S. EPA should dispense with any reservations it might have about the preferred option it has offered of assigning a unique identification number to pr each and every allowance. There is strong argument in favor of the unique ID number approach. It provides greater flexibility for tax purposes. It provides greater certainty in ownership, thus reducing conflicts and disputes.

It also will prove out, I think, as an important research tool in future years as the Acid Rain Program is evaluated and for purposes of applying lessons learned in the allowance program to other areas of environmental protection.

The EPA and others will be able to track allowances through the system much more easily, and it is a little bit like tagging a duck or something.

Finally, U.S. EPA should consider

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carefully the possibility of outsourcing at least two aspects of tracking of the allowance system. One would be the tracking system itself, and perhaps outsourcing the development and operation of that to a firm skilled in the operation of complex electronic information systems.

Secondly, as it has, it should proceed to consider outsourcing of the auction.

I would note that with respect to at least the tracking system and the outsourcing there, attention might be given in the future to some set of modest fees for accessing the system or for using the system, perhaps, to compile information other than in its raw form. That might produce a self-sustaining revenue flow, thus providing a better basis for an expectation of quality over the years.

In any event, I think we all appreciate the fact that EPA has scheduled these hearings here in Chicago. I would note only for those people not from Chicago who are in

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attendance that they should take the opportunity to visit the Museum here before they go home.

Thank you very much.

HEARING OFFICER KERTCHER: Thank you.

Is there anyone else in the audience that would like to make a presentation?

Not seeing any, I would like to once again thank all the speakers for their testimony. It is really evident there are a number of different points of view on various subjects. The task ahead of EPA now is to digest this testimony, as well as the comments that will be received up through February 3rd.

And, as is obvious, the second day of the hearing in Chicago will not be necessary.

The hearing is now over.

(WHEREUPON, at 12:05 p.m. the hearing was closed.)

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STATE OF ILLINOIS)
) SS:
COUNTY OF C O O K)

I, EDWARD A. GANS, a Certified Shorthand Reporter of the State of Illinois, do hereby certify that I reported in shorthand the proceedings had at the hearing aforesaid, and that the foregoing is a true, complete and correct transcript of the proceedings of said hearing as appears from my stenographic notes so taken and transcribed under my personal direction.

IN WITNESS WHEREOF, I do hereunto set my hand at Chicago, Illinois, this 13th day of January, 1992.

Notary Public, Cook County, Illinois.
My commission expires September 20, 1995.

C.S.R. Certificate No. 84-0428.