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STATE OF ILLINOIS
Pollution Control Board

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
PROPOSED NEW 35 Ill. ADM. CODE 217, SUBPART U,	)	R01-17
NOx CONTROL AND TRADING PROGRAM FOR	)	(Rulemaking-
SPECIFIED NOx GENERATING UNITS, SUBPART X,	)	Air)
VOLUNTARY NOx EMISSIONS REDUCTION PROGRAM,	)	
AND AMENDMENTS TO 35 ILL. ADM. CODE 211	)	

<u>TESTIMONY OF RICHARD FORBES</u>

Good Morning. My name is Richard Forbes. I am the manager of the Ozone Regulatory Unit, in the Air Quality Planning Section of the Bureau of Air, Illinois EPA. I have been employed by the Illinois EPA in this capacity for 15 years. Prior to that I served as a unit manager in the Permit Section of the Bureau of Air, and I also served in the Permit Section of the Bureau of Water. In all, I have been employed by the Illinois EPA for 29 years. My educational background includes a Bachelor of Science degree in General Engineering from the University of Illinois at Urbana-Champaign, and a Master of Science degree in Environmental Engineering from Southern Illinois University at Carbondale. I am also a licensed Professional Engineer in the State of Illinois.

As part of my regular duties in the Air Quality Planning Section, I supervised the preparation of emission estimates for various source categories used in the development of the 1990 ozone season weekday emissions inventories, development of control technologies applicable to volatile organic material ("VOM") emissions sources utilized in the preparation of the Rate-of-Progress plans for the Chicago and St. Louis ozone nonattainment areas, and development of regulations for the control of VOM emissions from source categories included in the Rate-of-Progress plans. Regarding the proposal before you today, I have been involved in the development of the regulations to limit emissions of nitrogen oxides ("NOx") from non-electrical generating units ("non-EGUs"), and I supervised the preparation of the Technical Support Document ("TSD") for the proposal.

Industrial boilers, turbines, or combined cycle units whose primary purpose is to produce steam or electricity for a source's own use are defined as non-EGUs. Non-EGU boilers produce steam or hot water for use in industrial processes or space and process heating and for the generation of mechanical power and electricity. Non-EGU gas turbines are used for driving gas and oil pipeline transmission equipment, the generation of electric power for both standby and continuous needs and the cogeneration of electricity and process steam for industrial use.

NOx emissions are the high-temperature byproduct of the combustion of fuel and air. When fuel is burned with air, nitric oxide ("NO"), the primary form of NOx, is formed mainly from the high temperature reaction of atmospheric nitrogen and oxygen (thermal NOx) and from the reaction of organically bound nitrogen in the fuel with oxygen (fuel NOx).

The Illinois EPA is proposing a regulation to cap the NOx emissions from large fossil fuel-fired non-EGUs having design capacities greater than 250 million British thermal units per hour ("mmBtu/hr"). Illinois EPA has identified 45 such non-EGU boilers and turbines meeting this large definition. As part of the evaluation of the control of NOx emissions from non-EGUs, the Illinois EPA relied upon several sources of guidance. In January 1993 and March 1994, the United States Environmental Protection Agency ("U.S. EPA") published two Alternative Control Techniques Documents ("ACTs") to control NOx emissions from industrial/commercial/institutional ("ICI") boilers and stationary gas turbines, respectively. These ACT documents contain detailed information which describe the sources of NOx emissions, various techniques for controlling NOx emissions, and the costs of these controls. The Illinois EPA used information contained in the ACTs as background information, but relied on the information contained in the Regulatory Impact Analysis for the NOx SIP Call published as part of the regulatory docket for the NOx SIP Call, 63 Fed. Reg. 57356 (October 27, 1998), the proposed Federal Implementation Plan ("FIP"), published at 63 Fed. Reg. 56394 (October 21, 1998), and U.S. EPA's proposed findings on the various petitions filed under Section 126 of the CAA ("Section 126 Petitions"), published at 65 Fed. Reg. 2674 (January 18, 2000), for the costs and economic impacts of today's proposal.

In the NOx SIP Call, U.S. EPA identified reductions that could be achieved from large existing NOx sources in the 23 jurisdictions affected by the NOx SIP Call using "highly cost-effective measures". Existing emission units under the NOx SIP Call are ones which commenced operation before January 1, 1995. U.S. EPA established NOx emission caps for these large existing non-EGUs based upon the application of a 60% reduction in uncontrolled base case emissions, a level of reduction U.S. EPA determined to be highly cost effective. Emissions from these units comprise the non-EGU inventory that serves as the basis for the large non-EGU emissions budget. U.S. EPA anticipated that initial allocations would be made to these units under the federal NOx trading program, and all other (new) non-EGU units would receive their allowances through the new source set-aside.

To determine the budget allowances for the existing large Illinois non-EGUs, U.S. EPA established a 1995 base year inventory representing actual 1995 emissions. The 1995 NOx emissions for each non-EGU included any controls present on the unit and were then projected to 2007 by multiplying the 1995 emissions with a 1995-2007 growth factor. These projected 2007 NOx emissions are termed the 2007 base case emissions. The Illinois EPA relied on U.S. EPA's economic growth model ("E-GAS") to provide the growth factors for each of the 45 large non-EGU emissions units. The 2007 base case NOx emissions from these large non-EGU boilers and turbines were calculated to be 9,078 tons per season ("TPS").

The budget allowance for each large non-EGU emissions unit was calculated by applying a 60% reduction to the emissions unit's uncontrolled 2007 base level. The total NOx allowances for all 45 affected units in Illinois are 4,882 tons per control period. Although the Illinois EPA had originally identified 45 large non-EGUs, during the development of the regulation the Illinois EPA learned that Indian Refining Limited Partnership, which operated three non-EGUs, had gone out of business and had withdrawn all of its operating permits. After discussing this situation with the stakeholders, Illinois EPA is proposing to allocate the 4,882 allowances to the remaining 42 non-EGUs. Appendix E of the proposed rulemaking, which is identical to Attachment A of the TSD, identifies each of the 42 impacted non-EGUs and each unit's associated NOx allowances.

The potentially impacted 42 non-EGUs are comprised of 18 coal-fired boilers, 23 oil- and gas-fired boilers, and one gas turbine. The estimated NOx reductions from the proposed regulation are 4,196 tons per control period. This represents an overall reduction of 46 percent from the large non-EGU boilers and turbines in Illinois.

The ACTs discuss the various control measures available for reducing emissions from non-EGUs. Controls can be grouped into two categories: combustion controls where the emphasis is on reducing NOx formation, and post-combustion controls which destroy the NOx formed in the combustion process. The reduction of NOx emissions from non-EGUs can be accomplished with either type of control or with a combination of these controls.

A number of combustion control techniques are available to reduce NOx emissions from non-EGUs. The application of a specific technique will depend upon the type of unit, the characteristic of its primary fuel, and method of firing. Most combustion controls work by designing boiler configurations so as to prolong combustion at lower temperatures rather than quickly completing it at higher temperatures ("staging" the combustion), by creating combustion zones that are fuel rich and thus oxygen poor, and by creating lower overall temperatures. Combustion control techniques include taking burners out of service ("BOOS") to maintain a staging atmosphere within the furnace, and using low excess air ("LEA") so as to limit the contact between oxygen and nitrogen, and flue gas recirculation ("FGR") which lowers peak flame temperature by adding a large mass of cool, inert gas to the fuel air mixture, reducing air to the primary burners and adding ports for overfire air ("OFA"), and providing for "reburning" wherein a portion of the fuel is burned in a second combustion area above the main combustion area. The most common single combustion control technique, however, is the low NOx burner ("LNB"), a burner especially designed to stage combustion and to provide for lower combustion temperatures.

Staging of combustion air ("SCA"), LNB, reburn (also called fuel staging with SCA), and LNB with SCA are the most effective techniques for pulverized coal–fired boilers affected by the regulation. The average NOx emission reductions achievable with these techniques are in the range of 27% to 60%. For coal-fired fluidized-bed combustion boilers, SCA, and flue gas recirculation ("FGR") with SCA techniques can reduce NOx emissions by 58% on average. FGR, LNB, and LNB with FGR are very effective NOx control techniques for gas- and oil-fired boilers affected by the proposal. The average range of NOx emission reduction efficiencies for these techniques is 58% to 76%.

For the gas turbines affected by the proposal, water or steam injection and dry low-NOx combustion design are two techniques to lower combustion temperatures, thereby reducing NOx. These techniques can achieve 60% to 90% reductions in NOx emissions from gas turbines, and are the most likely controls to be used to reduce NOx emissions to meet the requirements of this proposal.

In regard to post-combustion controls, the most common techniques are two commercially available flue gas treatments: selective non-catalytic reduction ("SNCR") and selective catalytic reduction ("SCR"). SNCR involves injecting ammonia ("NH_3") or urea into the flue gas to yield elemental N_2 and water. The ammonia or urea must be injected into the specific high-temperature zones in the upper furnace or convective pass for this method to be effective. Depending on the fuel type, 50% to 80% NOx reduction can be achieved with ammonia injection. For urea-based systems, the NOx reduction efficiencies are in the range of 25% to 88%.

The SCR process takes advantage of the selectivity of ammonia to reduce NOx to nitrogen and water at lower temperatures in the presence of a catalytic surface. NOx reduction efficiencies with SCR have been reported in the range of 53% to 90% for non-EGU boilers and gas turbines.

The ACTs describe the costs of various NOx controls applicable to non-EGU boilers and gas turbines. Depending on the type and size of the unit, the cost effectiveness of each control varies from a few hundred to several thousands dollars per ton of NOx removed. Since the NOx SIP Call and this regulatory proposal are based on controlling large non-EGUs (i.e., a boiler or turbine greater than 250 mmBtu/hr design capacity), data for those sizes of units were extracted from the ACT. Tables 3 and 4 of the TSD summarize the cost effectiveness of various control options for large non-EGUs. For coal-fired boilers, the cost effectiveness of controls varies from $180 to $4,800 per ton of NOx removed. For oil- and gas-fired boilers, the cost effectiveness of controls varies from $150 to $7,450 per ton of NOx removed. The cost estimates described in the ACTs are for background information and do not include the impact of emissions trading.

In order to allow the most cost effective emission reduction alternatives to be implemented, the proposal provides for participation in the federal NOx Budget Trading Program administered by the U.S. EPA. Each of the States subject to the NOx SIP Call is encouraged to participate in this NOx Budget Trading Program and thereby provide a mechanism for sources to achieve more cost effective NOx reductions. U.S. EPA has conducted a least-cost analysis for non-EGU boilers and turbines. The least-cost analysis is U.S. EPA's attempt to simulate the outcome of an efficient emissions trading program by assigning control responsibility based on sources with the lowest control costs. The least-cost analysis only reflects the efficient allocation of control responsibility among the group of industrial boilers and turbines. In the NOx SIP Call, U.S. EPA projected a compliance cost effectiveness for non-EGU boilers and gas turbines of $1,467/ton of NOx reduced in a control period when trading was included.

The trading currency in the federal NOx Budget Trading Program is a NOx Allowance, equal to one ton of NOx emitted during the control period of May 1 through September 30. Under the federal NOx Budget Trading Program, each emission unit would be given a certain number of NOx allowances. If a unit's actual NOx emissions exceed its allocated NOx allowances, the unit may purchase additional allowances from any other unit participating in the NOx trading program. Conversely, if a unit's actual NOx emissions are below its allocated NOx allowances, then it may sell the additional NOx allowances to other participating units. Such a program creates a competitive market for NOx allowances that encourages the use of the most efficient means for reducing NOx emissions. The federal NOx trading program allows units that do not use their NOx allowances for a given year to save or bank them for later use, subject to flow control measures. Trading may occur among any of the units within the SIP Call region participating in the federal NOx trading program. A detailed description of the federal NOx trading program is contained in the Federal Register notice of October 27, 1998, and proposed as 40 CFR Part 96.

In summary, in order to comply with the federal NOx SIP Call, which requires affected states to meet statewide NOx emissions budgets, the Illinois EPA is proposing to require large non-EGU boilers and turbines within the state to comply with an emissions cap, established by U.S. EPA as 4,882 tons of NOx during the ozone season control period, and to allow these sources to participate in the federal NOx trading program.

The Illinois EPA has relied on the information contained in the NOx SIP Call in developing the proposed Subpart U that requires the NOx emissions from large non-EGUs boilers and turbines greater than 250 mmBtu/hr design capacities to be capped at their 2007 budget emissions. The requirements of the proposed regulations are consistent with the NOx SIP Call requirements and will impact 42 emission units in Illinois. The statewide 2007 base NOx emissions are estimated to be 9,078 from large non-EGUs boilers and turbines. The proposed regulations will achieve a NOx reduction of 4,196 tons per control period or approximately 27 tons per day. A number of control technologies are available to allow sources to meet the required levels of control. It is anticipated that the most likely control will be the use of combustion control techniques, although there are post-combustion control techniques available that will meet the requirements of the proposed rule. Participation in the national NOx trading program will allow sources to make decisions of how to control their emissions to meet their budget, to over-control their sources and trade excess reductions in the market, or to limit control and purchase needed reduction allowances from the market. U.S. EPA has determined the cost effectiveness of NOx controls to meet the reduction requirements of the proposed rule in 1990 dollars to be $1,467 ($1,583 in 1999 $) per ton of NOx reduced.