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STATE OF ILLINOIS
Pollution Control Board

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:

	)	R01- 16
PROPOSED AMENDMENTS TO 35 Ill. ADM. CODE 217,	)	(Rulemaking Air)
SUBPART V, ELECTRIC POWER GENERATION	)	

TESTIMONY OF YOGINDER MAHAJAN

Good Morning. My name is Yoginder Mahajan. I am employed as an Environmental Protection Engineer in the Air Quality Planning Section in the Bureau of Air of the Illinois Environmental Protection Agency ("Illinois EPA"). I have been employed in this capacity since March 1992. Prior to my employment with the Illinois EPA I worked for various metal fabrication industries for nine years. My educational background includes a Bachelor of Engineering Degree in Mechanical Engineering from Bhopal University at Bhopal, India.

As part of my regular duties in the Air Quality Planning Section, I have prepared emission estimates for various source categories used in the development of the 1990 ozone season weekday emissions inventories; evaluated 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 assisted in the 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 NOx regulations for electrical generating units ("EGUs"), and I have prepared the Technical Support Document ("TSD") for this proposal.

As the TSD points out, the rotary motion of turbines through a magnetic field generates the electricity that is produced by the utility industry. A large output of electricity, the amount that is required every day of the year, is ordinarily generated by turbines turned by a flow of steam produced in boilers. This more or less constant electrical load is termed "base load". Base load units are supplemented, as needed, by "cycling" units which may be gas- or oil-fired.

An extra amount of electricity, such as that required to run many air conditioners during very hot summer days, is generated in turbines turned by a flow of steam produced in gas- or oil-fired boilers that can be quickly brought on line, or in gas- or oil-fired gas turbines, wherein the same turbine that is making the electricity is turned by the flow of combustion gases produced from burning gas or fuel oil. Units producing electricity that are required only on high demand days are called "peaking units" or simply "peakers." Smaller coal-fired units are also sometimes used as peakers although they cannot come on line as quickly as gas- or oil-fired units.

Combustion of fuel in the boilers and gas turbines produces nitrogen oxides ("NOx"). The ambient air consists of about 20% oxygen which when heated to elevated temperatures will combine with the elements of coal, fuel oil, or natural gas, i.e. carbon and hydrogen, to yield carbon dioxide and water vapor, and to generate still more heat which will sustain combustion. Ambient air, however, also contains almost 80% nitrogen, which does not react with its oxygen component to form NOx at ambient temperatures, but will do so at the elevated temperatures that occur during a fuel's combustion. This reaction takes place at an increased rate as the temperature of combustion rises, and also with increasing amounts of excess air. In addition, coal and fuel oil contain appreciable amounts of nitrogen that can also combine with oxygen to form still more NOx at combustion temperatures.

Today's proposal is to control NOx emissions from large fossil-fuel-fired EGUs that have nameplate capacities greater than 25 megawatts of electricity ("MWe"). As part of the evaluation of the control of NOx emissions from EGUs, the Illinois EPA identified several sources of guidance. The United States Environmental Protection Agency ("USEPA") published two Alternative Control Techniques ("ACT") documents regarding control of NOx emissions from utility boilers and gas turbines. 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 USEPA'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.

To determine the NOx emissions for the existing large Illinois EGUs, the Illinois EPA used the actual 1996 heat input data reported by the existing emissions units to the Acid Rain Division of the USEPA. The "heat input" of fuel burning equipment is the amount of heat energy, usually as measured in millions of British thermal units ("mmBtu"), produced by the burning of the fuel for a given period of time, usually an hour. Base 2003 heat input values were calculated by multiplying actual 1996 heat input with a 1996 – 2003 growth factor which was calculated based on the 1996 – 2007 growth factor of 1.08, as predicted by USEPA's Integrated Planning Model ("IPM"). The 2003 base emissions were calculated by multiplying the unit's base 2003 heat input with an emission rate, in lb/mmBtu, and divided by 2,000 lb/ton. The emission rates used for calculations were the Acid Rain Control limits and when the unit was not subject to Acid Rain Control limit, an actual average 1996 emission rate reported by the sources to the USEPA was used. The total 2003 base NOx emissions from the existing impacted 103 EGUs were calculated to be 113,340 ton per control period.

The 2003 controlled NOx emissions from the 103 affected units by the proposal were calculated by applying a proposed emission rate of 0.25 lb/mmBtu to each unit's 2003 heat input. The total regulated 2003 control period NOx emissions were estimated to be 49,790 tons. This represents a reduction of 63,550 tons of NOx emissions or an average reduction of 56% from base 2003 NOx emission levels. Attachment A to the TSD, identifies each of the 103 impacted EGUs and each unit's associated NOx emissions data.

The largest number of units affected by the proposal are coal-fired units which can be classified as either dry bottom pulverized coal-fired boilers or as cyclone boilers, with the pulverized coal-fired boilers further classified as to firing method, i.e., either as tangentially-fired or as wall-fired. These classifications are important because each classification has different characteristic uncontrolled NOx emissions and control costs.

The units having the highest total NOx emissions in Illinois are cyclone boilers. Cyclone boilers are those in which crushed coal is fed tangentially in a stream of primary air to a horizontal cylindrical furnace. In a cyclone boiler much of the ash forms a liquid slag on the furnace walls and must be drained to the furnace bottom where it can be removed through a slag tap opening. There are 22 cyclone boilers affected by the proposed regulations, having projected base 2003 NOx emissions of 56,579 tons during the May 1 through September 30 control period.

The units having the second highest total NOx emissions are tangentially-fired dry bottom pulverized coal boilers having uncontrolled NOx emissions. Tangentially-fired units fire fuel in burners mounted in a corner, or in opposite corners, of a furnace with a rectangular cross section. The fuel is called "pulverized" coal because the coal is pulverized to the consistency of talcum powder in mills designed for that purpose. The term "dry bottom" refers to the fact that the furnace is designed so that no ash collects in a liquid state on its walls. (There are no wet bottom pulverized coal boilers in Illinois.) Projected base 2003 NOx emissions from the 34 tangentially-fired dry bottom pulverized coal boilers affected by the regulatory proposal total 43,047 tons during the control period.

Wall-fired dry bottom pulverized coal boilers are the third largest NOx emitting category of units affected by the regulatory proposal. Wall-fired units are similar to tangentially-fired units except that the burners are mounted in a wall, or in opposite walls, of the furnace rather than in the corners. There are only eight wall-fired dry bottom pulverized coal boilers affected by the proposal with projected base 2003 control period NOx emissions of 9,130 tons.

The fourth NOx emitting category of EGUs affected by the regulatory proposal is gas- and oil-fired boilers. There are 25 gas- and oil-fired boilers impacted by the proposal and which account for 2,234 tons of 2003 base control period NOx emissions.

The last category of EGUs affected by the regulatory proposal is gas turbines. There are 14 existing gas turbines affected by the proposal and they are generally used to meet peak electricity demand. The total NOx emissions from this category are 2,351 tons per 2003 base control period.

A number of NOx control technologies are available to reduce NOx emissions from EGUs. They can be either combustion controls or post combustion controls. Combustion control consists of changing the circumstances of boiler or turbine combustion so as to minimize the amount of NOx generated during that combustion, while post combustion control treats already generated combustion gases so as to reduce those gases' NOx component to nitrogen and water vapor.

Most combustion controls are designed 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, using low excess air ("LEA") so as to limit the contact between oxygen and nitrogen, and staging combustion via biased firing ("BF") of air-fuel ratios in some burners, 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. LNBs can achieve a 35 to 45% NOx reduction when installed on tangentially-fired pulverized coal boilers, a 40 to 50% reduction when installed on wall-fired pulverized coal boilers, and a 30 to 50% reduction when installed on gas- or oil-fired boilers. The burner's NOx reduction efficiency can be improved still further when used in conjunction with other combustion control techniques such as OFA. LNBs, however, are not available for cyclone boilers.

The only other single combustion control technique that can equal, or even exceed, the efficiency of the LNB is reburn. Reburn with natural gas is usually a more suitable technique than reburn with coal or oil, even if those latter fuels are the boiler's primary fuel. Reburn alone is capable of achieving a 50 to 60% NOx reduction from gas-, oil- and coal-fired boilers, including cyclone boilers.

The other combustion control technique besides reburn is LNB, which can allow gas- and oil-fired boilers to meet the proposed regulatory requirements.

Gas- or oil-fired gas turbines can be controlled by the injection of either water or steam into the intake of the turbine. This control technique retards NOx formation by lowering the operating temperature of the turbine and can provide a 70 to 90% reduction in NOx emissions, which may be sufficient to meet the requirements of the regulatory proposal. A special retrofit firing configuration, known as the "low NOx combustor" is available for some gas turbines. This technique can provide a 60 to 90% reduction in NOx emissions.

Two post-combustion control techniques that are available for fossil-fuel-fired boilers are selective non-catalytic reduction ("SNCR") and selective catalytic reduction ("SCR"). Both these techniques are called "reduction" techniques because the NOx is reduced back to elemental nitrogen and oxygen, with the oxygen combining with hydrogen to form water in the process.

Both techniques are called "selective" because both specifically select NOx for reduction unlike the catalytic reduction that is applied to the exhaust of motor vehicles and which reduces a wide variety of pollutants. In both SNCR and SCR, ammonia, a compound of nitrogen and hydrogen, is made to react with NOx in order to liberate the nitrogen from each reactant and produce gaseous nitrogen and water. In SNCR, urea, another nitrogen and hydrogen compound which also contains carbon, is often used instead of ammonia.

The advantage of SNCR over SCR is cost, because the SNCR reactions take place without the use of a catalyst, the chief component of the cost of an SCR system. The disadvantages of SNCR are that it effectively operates over a rather narrow range of temperatures which may not be appropriate for some boilers, that it is difficult to control the loss of ammonia, an air pollutant in its own right, to the ambient atmosphere, and that its NOx removal efficiencies, 30 to 60%, compare unfavorably with SCR's 75 to 85% NOx removal efficiencies for coal-fired boilers.

In general, gas- and oil-fired boilers SNCR's reduction efficiencies are even poorer, 25 to 40%, while SCR's efficiencies are even better, 80 to 90%. SNCR may not be suitable for gas turbine applications, while SCR is capable of providing 90% NOx reductions for such turbines.

The TSD for this proposal has a summary of the costs of various NOx control technologies and their combinations under various "load" conditions based on the information contained in the ACT documents. The costs of combustion controls for gas- and oil-fired boilers vary widely depending upon the size of the unit, the load conditions, and the type of control technology employed. Table 5-2 in the TSD provides a summary of the large variety of cost effectiveness values for the NOx control options for these boilers. For gas turbines that continue to operate as peakers, the most likely control that would be utilized is water and steam injection. The cost effectiveness range for this control option is $1,210 to $2,350 per ton of NOx removed. (If these units are used more often than as peaking units, the cost per ton would be less.)

Control costs for coal-fired boilers relying on SNCR technology also vary widely for base load units with an average range of cost effectiveness of $725 to $880 per ton of NOx reduced. Control costs relying on SCR technology have a similar average range of cost effectiveness of $1,035 to $2,035 per ton for base load units.

In order to estimate the cost effectiveness of the proposal, Illinois EPA is relying on USEPA's cost data presented in the Regulatory Impact Analysis for the NOx SIP Call. USEPA analyzed the results of cost effectiveness based on the "0.15 uniform alternative" without trading between sources within state boundaries. The cost difference between uniform alternatives with interstate trading and without interstate trading is approximately two percent. If states adopt rate-based approaches, the cost could be expected to be higher. The RIA document indicated that costs could be as much as 30% higher if trading is restricted.

Table 5-4 of the TSD shows the various NOx emissions reduction levels and the annual costs and cost effectiveness that the USEPA estimates for the potentially affected part of the electric power industry in the years 2003, 2005, 2007, and 2010. As shown in the table, the average costs per control season ton of NOx removed under the "0.25 uniform alternative" with trading for 2003 is

$1,127 per ton of NOx removed. The Illinois EPA used this information and estimated the cost effectiveness to comply with its proposal of a 0.25 lb/mmBtu rate-based NOx emission standard with no cap and trading program to be $1,465 (1990 dollars) per ton of NOx reduced in a 2003 control period, an increase of 30% in the average cost effectiveness under the "0.25 uniform alternative" with trading. The Illinois EPA believes that the cost estimates are conservative. The proposal allows emission averaging among the Appendix F EGUs and certain units at Soyland Power. The Illinois EPA anticipates the cost effectiveness of this proposal to be much less than the estimated cost effectiveness of $1465 per ton of NOx reduced when the affected sources participate in the mutually agreed upon NOx averaging plans.

In summary, the results of Illinois EPA's modeling analysis indicates that an emission rate of 0.25 lb/mmBtu for large EGUs is sufficient to demonstrate attainment of the 1-hour ozone NAAQS in the Metro-East St. Louis area. All of these controls are assumed to be in place by May 1, 2003.

The Illinois EPA has relied on the information contained in the NOx SIP Call and USEPA's guidance documents in developing the proposed Subpart V that requires the NOx emissions from large EGUs greater than 25 MWe nameplate capacities to meet a rate-based NOx emission limit of 0.25 lb/mmBtu. The requirements of the proposed regulations will impact 103 existing emission units in Illinois and will result in an overall 56% reduction in base 2003 NOx emissions or a total of 63,550 tons of NOx reduced per ozone season. A number of control technologies are available to allow sources to meet the required level of control, although it is anticipated that the most likely control will be the use of combustion controls and some SCR or SNCR or some combination of such technologies. The cost effectiveness of NOx controls to meet the reduction requirements of the proposed rule has been determined to be, in 1990 dollars, $1,465 per ton of NOx reduced.

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