Illinois Environmental Protection Agency

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Letter dated May 16, 2000, to Mr. Francis X. Lyons, Regional Administrator, USEPA Region 5 from Thomas V. Skinner, Director, Illinois EPA. Letter dated June 15, 2000, to Thomas V. Skinner, Director, Illinois EPA from Francis S. Lyons, Regional Administrator, USEPA Region 5.	3
"Alternative Controls Technology Document-NOx Emissions from Stationary Gas Turbines", USEPA Office of Air and Radiation Emission Standards Division, January 1993, EPA-453/R-93-007.	4
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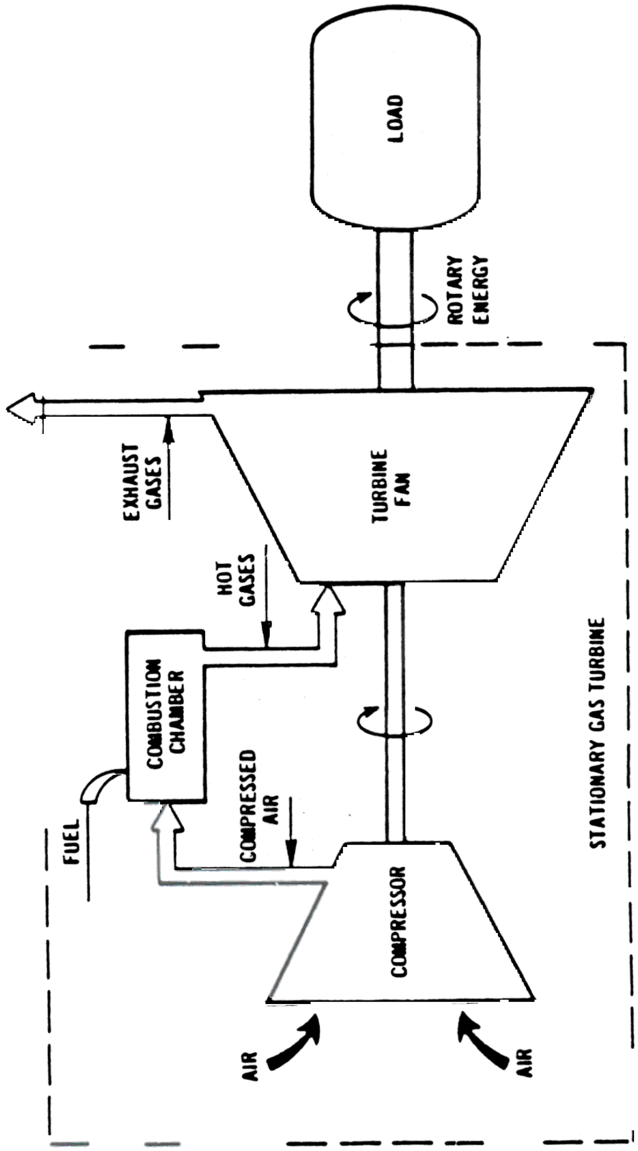

Simple cycle gas turbine application.

Illinois EPA
Exhibit No. 1

3.1 Stationary Gas Turbines

3. 1.1 General'

Gas turbines, also called "combustion turbines", are used in a broad scope of applications including electric power generation, cogeneration, natural gas transmission, and various process applications. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to [2] over 268,000 hp, with an average size of 40,200 hp. The primary fuels used in gas turbines are natural gas and distillate (No. 2) fuel oil.[3]

3.1.2 Process Description,2

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that encircles the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate several can-shaped combustion chambers rather than a single continuous chamber. Annular and can-annular combustors are based on aircraft turbine technology and are typically used for smaller scale applications. A silo (frame-type) combustor has one or more combustion chambers mounted external to the gas turbine body. Silo combustors are typically larger than annular or can-annular combustors and are used for larger scale applications.

The combustion process in a gas turbine can be classified as diffusion flame combustion, or lean-premix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NOx combustors. The majority of gas turbines currently manufactured are lean-premix staged combustion turbines.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at temperatures up to 2600'F. Energy from the hot exhaust gases, which expand in the power turbine section, are recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load.[2] Gas turbines may have one, two, or three shafts to transmit power between the inlet air compression turbine, the power turbine, and the exhaust turbine. The heat content of the exhaust gases exiting the turbine can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).

Illinois EPA
Exhibit No. 2

The simple cycle is the most basic operating cycle of gas turbines with a thermal efficiency ranging from 15 to 42 percent. The cycle thermal efficiency is defined as the ratio of useful shaft energy to fuel energy input. Simple cycle gas turbines are typically used for shaft horsepower applications without recovery of exhaust heat. For example, simple cycle gas turbines are used by electric utilities for generation of electricity during emergencies or during peak demand periods.

A regenerative cycle is a simple cycle gas turbine with an added heat exchanger. The heat exchanger uses the turbine exhaust gases to heat the combustion air which reduces the amount of fuel required to reach combustor temperatures. The thermal efficiency of a regenerative cycle is approximately 35 percent. However, the amount of fuel efficiency and saving may not be sufficient to justify the capital cost of the heat exchanger, rendering the process unattractive.

A cogeneration cycle consists of a simple cycle gas turbine with a heat recovery steam generator (HRSG). The cycle thermal efficiency can be as 84 percent. In a cogeneration cycle, the steam generated by the HRSG can be delivered at a variety of pressures and temperatures to other thermal processes at the site. For situations where additional steam is required, a supplementary burner, or duct burner, can be placed in the exhaust duct stream of the HRSG to meet the site's steam requirements.

A combined cycle gas turbine is a gas turbine with a HRSG applied at electric utility sites. The gas turbine drives an electric generator, and the steam from the HRSG drives a steam turbine w1iich also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle gas turbine is between 38 percent and 60 percent.

Gas turbine applications include gas and oil industry, emergency power generation facilities, independent electric power producers (IPP), electric utilities, and other industrial applications. The petroleum industry typically uses simple cycle gas turbines with a size range from 300 hp to 20,000 hp. The gas turbine is used to provide shaft horsepower for oil and gas production and transmission. Emergency power generation sites also utilize simple cycle gas turbines. Here the gas turbine is used to provide backup or emergency power to critical networks or equipment. Usually, gas turbines under 5,000 hp are used at emergency power generation sites.

Independent electrical power producers generate electricity for resale to larger electric utilities. Simple, regenerative, or combined cycle gas turbines are used at IPP; however, most installations use combined cycle gas turbines. The gas turbines used at IPP can range from 1,000 hp to over 100,000 hp. The larger electric utilities use gas turbines mostly as peaking units for meeting power demand peaks imposed by large commercial and industrial users on a daily or seasonal basis. Simple cycle gas turbines ranging from 20,000 hp to over 200,000 hp are used at these installations. Other industrial applications for gas turbines include pulp and paper, chemical, and food processing. Here, combined cycle gas turbines are used for cogeneration.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NOx), carbon monoxide (CO), and to a lesser extent, volatile organic compounds (VOC). Particulate matter (PM) is also a primary pollutant for gas turbines using liquid fuels. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion. Trace to low amounts of HAP and sulfur dioxide (S02) are emitted from gas turbines. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Oxides of sulfur (SOX) will only appear in a significant quantity if heavy oils are fired in the turbine. Emissions of sulfur compounds, mainly SO_2, are directly related to the sulfur content of the fuel.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors for this sections are presented for gas turbines operating under high load conditions. Section 3.1 background information document and emissions database contain additional emissions data for gas turbines operating under various load conditions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

If the HRSG is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal units [lb/MMBtu]) will also apply to cogeneration/combined cycle systems. If the HRSG is supplementary fired, the emissions attributable to the supplementary firing must also be considered to estimate total stack emissions.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel is thermal NOX, which arises from the thermal dissociation and subsequent reaction of nitrogen (NO and oxygen (02) molecules in the combustion air. Most thermal NOX is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface.

The second mechanisrn, called prompt NOX, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NOX forms within the flame and is usually negligible when compared to the amount of thermal NOX formed. The third mechanism, fuel NOX, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NOx formed from natural gas combustion is thermal NOX. Distillate oils have low levels of fuel-bound nitrogen. Fuel NOX from distillate oil-fired turbines may become significant in turbines equipped with a high degree of thermal NOX controls. Otherwise, then-nal NOX is the predominant NOx formation mechanism in distillate oil-fired turbines.

The maximum thermal NOX formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction- The control of stoichiometry is critical in achieving reductions in thermal NOx. Thermal NOx formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NOX can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall Levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place downstream of the primary flame, which does not minimize peak temperature in the flam; and suppress thermal NOX formation.

Diffusion flames are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and significant thermal NOX is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame, and therefore to thermal NOX emissions. Thermal NOX can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature, and therefore thermal NOX. Newer model gas turbines use lean, premixed combustion where the fuel is typically prernixed with more than 50 percent theoretical air which results in lower flame temperatures, thus suppressing thermal NOX formation.

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure. 4 Variations of emissions of 30 pe cent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam As beat energy is used for water to steam conversion, the temperature is the flame zone will decrease resulting in a decrease of thermal NOx formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NOX significantly. Similarly, the gas turbine operating loads affect NOX emissions. Higher NOx emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NOX.

3.1.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation Of CO to C02 at gas turbine temperatures is a slow reaction compare U-1 to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result fruit, quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized volatile organic emissions.

Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

3.1.3.3 Particulate Matter[13]

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state and can be measured on a EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half'of the sampling train. The collection, recovery, and analysis of the impingers is described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

3.1.3.4 Greenhouse Gases [5-11] -

Carbon dioxide (C02) and nitrous oxide (N20) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to C02 during the combustion process. This conversion is relatively independent of firing configuration. Methane (CH4) is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas or a product of combustion in the case of distillate fuel oil.

Although the formation of CO acts to reduce C02 emissions, the amount of CO produced is insignificant compared to the amount of C02 produced. The majority of the fuel carbon not converted to C02 is due to incomplete combustion.

Formation of N20 during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N20 is minimized when combustion temperatures are kept high (above 1475*F) and excess air is kept to a minimum (less than 1 percent).

3.1.3.5 HAP Emissions -

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, fonnaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired turbines, small amount of metallic HAP are present in the turbine's exhaust in addition to the gaseous HAP identified under gas fired turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, combustion turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

3.1.4 Control Technologies [12]

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NOX control, dry controls using advanced combustor design to suppress NOX formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NOX and/or oxidize CO emission from the turbine. Other recently developed technologies promise significantly lower levels of NOX and CO emissions from diffusion combustion type gas turbines. These technologies are currently being demonstrated in several installations.

Emission factors in this section have been determined from gas turbines with no add-on control devices (uncontrolled emissions). For NOX and CO emission factors for combustion controls, such as water-steam injection, and lean pre-mix units are presented. Additional information for controlled emissions with various add-on controls can be obtained using the section 3.1 database. Uncontrolled, lean-premix, and water injection emission factors were presented for NOx and CO to show the effect of combustion modification on emissions.

3.1.4.1 Water Injection -

Water or steam injection is a technology that has been demonstrated to effectively suppress NOX emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NOX levels, such rates of injection may reduce NOx by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typicality 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass Dow required to maintain turbine inlet temperature at manufacturer's specifications. B-NI, CIO and VOC emissions are increased by water injection, with the level of CO and VOC increases. dependent on the amount of water injection.

3.1.4.2 Dry Controls -

Since thermal NOx is a function of both temperature (exponentially) and tune (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging or decrease the residence time of the combustor. A combination of methods may be used to reduce NOX emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NOx formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage bums lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NOx emissions associated with the high temperature pilot flame are insignificant. Low NOX emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel which and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H2, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NOX generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NOX formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx.

3.1 A.3 Catalytic Reduction Systems -

. Selective catalytic reduction (SCR) systems selectively reduce NOx emissions by injecting ammonium (NH3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH3, and 02 react on the surface of the catalyst to form N2 and H20. The exhaust gas must contain a minimum amount of 02 and be within a particular temperature range (typically 450OF to 8500F) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850*17) cause NOX and NH3 to pass through the catalyst unreacted. Ammonia emissions, called NH3 Slip, may be a consideration when specifying an SCR system

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NOx emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems). The SCR system for landfill or digester gas-fired turbines requires a substantial fuel gas pretreatment to remove trace contaminants that can poison the catalyst. Therefore, SCR and other catalytic treatments may be inappropriate control technologies for landfill or digester gas-fired turbines.

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NOx, 02, and NH3, to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations incorporate CO catalytic oxidation modules along with the NOX reduction catalyst for simultaneous CO/NOX control.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (COD and water (H20) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants.

3.1.4.4 Other Catalytic Systems [14,15]

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NOx and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to C02 and N02. The N02 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of I ppm and NOX emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR system. Only limited emissions data were available for a gas turbine equipped with a SCONOX system This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims.

The XONON system is applicable to diffusion and lean-premix combustors and is currently being demonstrated with the assistance of leading gas turbine manufacturers. The system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NOX while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NOX, and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NOX. The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NOx levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm. Emissions data from gas turbines equipped with a XONON Catalyst were not available as of the drafting of this section.

3.1.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the new EFIG home page (http://www.epa.gov/ttn/chief).

Supplement A, February 1996

For the PM factors, a footnote was added to clarify that condensables and all PM from oil and gas-fired turbines are considered PM-10.

In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, 0.6 lb/106 ft' (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

Text was revised and updated for the general section.

Text was added regarding firing practices and process description.

Text was revised and updated for emissions and controls.

All factors for turbines with SCR-water injection control were corrected.

The C02 factor was revised and a new set of N20 factors were added.

Supplement F, April 2000

Text was revised and updated for the general section.

All emission factors were updated except for the S02 factor for natural gas and distillate oil turbines.

Turbines using staged (lean-premix) combustors added to this section.

Turbines used for natural gas transmission added to this section.

Details for turbine operating configurations (operating cycles) added to this section.

Information on new emissions control technologies added to this section (SCONOX and XONON).

HAP emission factors added to this section based on over 400 data points taken from over 60 source tests.

PM condensable and filterable emission factors for natural gas and distillate oil fired turbines were developed.

NOx and CO emission factors for lean-premix turbines were added.

Emission factors for landfill gas and digester gas were added.

Table3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NOX) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors'				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(104MBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02 d	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[c]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[F] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam injection	2.4 E-0 I	B	7.6 E-02	C
Landfill! Gas-Fired Turbines[g]	(1b/MM13tu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMbtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[i]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads (80 percent load) only. For information on units operating at other loads, consult the background report for tWs chapter (Reference 16), available at " www.epa.gov/ttn/chief'.

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60'F. To convert from (lb/MMBtu) to (lb/1 0^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, w1iich is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 NIMBtu/103 gallons. To convert from (lb/MMBtu) to (lb/ 103 gallons), multiply by 139. SCC for landfill gas-fired turbines is 2-03-008-01.

[h]Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60'F. To convert from lb/MMBtu), to lb/ 0^6 SCf) multiply by 400. SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60'F. To convert from (lb/MMBtu) to (lb/1 06 SCf) multiply by 600.

Table 3.1-2a. **EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES**

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines [b]		Distillate Oil-Fired Turbines [d]	
	(lb/MMbtu)c (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
$C0_2$ f	110	A	157	A
N_20	0.0032	E	ND	NA
Lead	ND	NA	1.4 E-05	C
$S0_2$	0.94S h	B	1.01S h	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1. 1 E-02	B	4.0 E-03[i]	C
PM (condensable)	4.7 E-03[i]	C	7.2 E-03[i]	C
PM (filterable)	1.9 E-03[i]	C	4.3 E-03[i]	C
PM (total)	6.6 E-03[i]	C	1.2 E-02[i]	C

[a] Factors are derived from units operating at high loads (80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief'. ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average f e natural gas heating value (HHV) of 1020 Btu/scf at 60'F. To

convert from (lb/NIMBtu) to (lb/10 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 NlMBtti/103 gallons. To convert from (lb/MMBtu) to (lb/ 103 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to C02 for natural gas and 99% conversion of fuel carbon to C02 for distillate oil. C02 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(Q(D), where %CON = weight percent conversion of fuel carbon to C02, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/l 06 scf For distillate oil, C02 (Distillate Oil) [lb/MMBtu] = (26.4 gaVMMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to S02. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on

Emission factors are based on combustion turbines using water-steam injection.

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Pollutants	Emission Factors[a] - Uncontrolled			
	Landfill Gas-Fired Turbines [b]		Digester Gas-Fired Turbines [d]	
	(lb/MMBtu)[c]	Emission Factor Rating	(lb/MMBtu)[e]	Emission Factor Rating
$C0_2$ [f]	50	D	27	C
Lead	WD	NA	< 3.4 E-06	D
PM-10	2.3 E-02	B	1.2 E-02	C
$S0_2$	4.5 E-02	C	6.5 E-03	D
VOC[h]	1.3 E-02	B	5.8 E-03	D

[a] Factors are derived from units operating at high loads (80 percent load) only. For information units operating at other loads, consult the background report for this chapter reference 16), available at www.epa.gov/ttn/chief. ND = No Data, NA = Not Applicable.

[b] SCC for landfill gas-fired turbines is 2-03-008-01.

[c] Emission factors based on an averafe landfill gas heating value (HHV) of 400 Btu/scf at 60T. To convert from (lb/MMBtu) to (lb/ 10^6scf), multiply by 400.

[d] SCC for digester gas-fired turbine include 2-03-007-01.

[e] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60'F. To convert from (lb/MMBtu) to (lb/I 06 SCf), multiply by 600.

[f] For landfill gas and digester gas, C02 is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent). Compound was not detected. The presented emission value is based on one-half of the detection limit.

[h] Based on adding the formaldehyde emission to the NMHC.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene [d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a]SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous_Air Pollutants as defined in Section 112 (b) of the *Clean.&r.4ct.*

[b] Factors are derived from units operating at high loads (80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at " www.epa.gov/ttn/chief'.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu./scf at 60'F. To convert from (lb/MMBtu) to (lb/l 06 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit. '

[e]Benzene with SCONOX catalyst is 9.1 E-07, rating of D.

[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.14. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 1.6 E-05	D
Benzene	5.5 E-05	C
Formaldehyde	2.8 E-04	D
Naphthalene	3.5 E-05	C
PAH	4.0 E-35	C

[a]SCCs for distillate oil-fired turbines include 2-01-001-Ol-, 2-02-001-01, 2-02-001-03., and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act.*

[b] Factors are derived fiom units operating at high loads (80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at www. epa.gov/ttn/cheif

[c] Emission factors based on an average distillate oil heating value (HIP,/) *of 139* MMMBtu/l0[3] convert from lb/MMBtu) to (lb/10[3] gallons), multiply by *139.*

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 1.1 E-05	D
Beryllium[d]	< 3.1 E-07	D
Cadmium	4.8 E-06	D
Chromium	1.1 E-05	D
Lead	1.4 E-05	D
Manganese	7.9 E-04	D
Mercury	1.2 E-06	D
Nickel[d]	< 4.6 E-06	D
Selenium[d]	< 2.5 E-05	D

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-6. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM LANDFILL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Acetonitrile [d]	< 1.2E-05	D
Benzene	2. 1 E-05	B
Benzyl Chloride[d]	< 1.2 E-05	D
Carbon Tetrachioride d	< 1.8 E-06	D
Chlorobenzene [d]	< 2.9 E-06	D
Chioroform[d]	< 1.4 E-06	D
Methylene Chloride	2.3 E-06	D
Tetrachloroathylene [d]	< 2.5 E-06	D
Toluene	1.1 E-04	B
Trichloroethylene d	< 1.9 E-06	D
Vinyl Chloride d	< 1.6 E-06	D
Xylenes	3.1 E-05	B

[a]SCC for landfill gas-fired turbines is 2-03-008-01. Hazardous Air Pollutants as defined in Section 112 (b) of the Clean Air Act.

[b] Factors are derived from units operating at high loads (80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief'.

[c]Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60'F. To convert from (lb/MMBtu) to (lb/ 10^6 scf), multiply by 400.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-7. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES'

Emission Factors[b] - Uncontrolled

Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Ratings
1,3-Butadiene[d]	< 9.8 E-06	D
1,4-Dichlorobenzene[d]	< 2.0 E-05	D
Acetaldehyde	5.3 E-05	D
Carbon Tdrachloride[d]	< 2.0 E-05	D
Chlorobenzene[d]	< 1.6 E-05.	D
Chloroform[d]	< 1.7 E-05	D
Ethylene Dichloride[d]	< 1.5 E-05	D
Formaldehyde	1.9 E-04	D
Methylene Chloride[d]	< 1.3 E-05	D
Tetrachloroethylene[d]	< 2.1 E-05	D
Trichloroethylene[d]	< 1.8 E-05	D
Vinyl Chloride[d]	< 3.6 E-05	D
Vinylidene Chloride[d]	< 1.5 E-05	D

[a]SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the Clean Air Act.

[b]Factors are derived from units operating at high loads (80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c]Emission factors based on an averafe digester gas heating value (HHV) of 600 Btu/scf at 60’f. To convert from (lb/MMBtu)) to lb/10^6 scf), multiply by 600.

[d]Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-8. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 2.3 E-06	D
Cadmiwn [d]	< 5.8 E-07	D
Chromium [d]	< 1.2 E-06	D
Lead[d]	< 3.4 E-06	D
Nickel	2.0 E-06	D
Selenium	1.1 E-05	D

[a]SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act.*

[b]Factors are derived from units operating at high loads (80 percent load) only. For more information on units operating at other loads, consult the background report for this chapter (Reference 16), available at “www.epa.gov/ttn/chief”.

[c]Emission factor based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.

[d]Compound was not detected. The presented emission value is based on one-half of the detection

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ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 North Grand Avenue East, P.O. Box 19276, SPRINGFIELD, ILLIMNS 62794-9276

THOMAS V. SKINNER, DIRECTOR

217/782-9540

May 16, 2000

Mr. Francis X. Lyons
Regional Administrator
U.S. Environmental Protection Agency, Region 5
R-19J
77 West Jackson Boulevard
Chicago, Illinois 60604-3507

Re: New Peaker Power Plants in the Chicago Area

Dear Frank:

On behalf of Governor Ryan, 1 am writing to request the assistance of the United States Environmental Protection Agency (US EPA) with regard to an issue that has developed recently in Illinois. The Illinois Environmental Protection Agency (Illinois EPA) has received a number of permit applications (over twenty to date) for new natural gas-fired electrical generation units (EGUs), commonly referred to as "peaker plants," in the northern Illinois area. We understand that other states are also receiving an increased number of permit applications, but it appears that the number coming into Illinois exceeds those of our neighbors by a. rather significant amount.

A number of members of the Illinois General Assemblv. local environmental groups, and citizens (some whose homes are near the sites chosen by the new EGU permit applicants), have raised concerns regarding air quality and health issues associated with the operation of these new plants, In permitting the new EGU.s, we have followed the federal new source review rules for prevention of significant deterioration (PSD), except in the Metro-East ozone nonattainment area where nonattainment New Source Review applies.

A number of parties have raised questions regarding the federal PSD rules. Specifically, they question the applicability of an annual emission threshold of 250 tons, to peaker plants that will operate primarily during the summer months (the peakers' 250 tons likely will be emitted within a three-month period -- and perhaps within a lesser period, since peakers operate only when demand is highest, which we estimate to be less than 20 days during the summer).

Illinois EPA
Exhibit No. 3

Furthermore, these new EGUs have. been limiting their proposed emissions to just below the PSD threshold, thus avoiding required application of best available control technology (BACT). As Illinois implements the federal program only, avoiding PSD means that such plants may be subject only to the new source performance standards (NSPS), which as you are aware are somewhat.less stringent.than BACT for these types of sources. This is being characterized as a "loophole" in the. PSD rules.

Our own air quality analyses of these proposed plants, performed as we receive the permit applications, indicate that their emissions will not cause violation of any of the relevant national ambient-air quality standards (NAAQS). While we do not model for ozone (it would be impossible, both physically and in terms of resources, to perform the necessary photochemical modeling for each of these permit.applications), we do not believe that the nitrogen oxides (NOx) emitted by these plants will result in violation of the ozone standard, particularly with anticipated reductions, of NOx downstate and regionally.

However, as we continue to analyze the developing peaker situation, we would appreciate hearing U.S. EPA's perspective, particularly with regard to the federal PSD rules and the alleged loophole. For example, does U.S. EPA agree with our interpretation of PSD? Does it agree that these plants should not significantly impact air quality or cause violations?

T'here is some urgency to this request, as we generally must act on applications for new EGUs within 180 days.

Thank you in advance for your assistance. Please contact either me or Dennis Lawler of my staff with any questions.

Sincerely,

Thomas V. Skinner
Director

cc: The Honorable George H. Ryan

UNITED STATES ENVIRONMENTAL PROTECTION AGE
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

JUN 22 2000
RECEIVED IN THE
OFFICE OF THE DIRECTOR

JUN 15 2000

REPLY TO THE ATTENTION OF
R-19J

BK
Dave Kolaz
Kathleen
JK
SE

RECEIVED
JUN 23 2000
IEPA - Bureau of Air
State of Illinois

Thomas V. Skinner, Director
Illinois Environmental Protection Agency
1021 North Grand Avenue East
P. O. Box 19276
Springfield, Illinois 62794-9276

Dear Mr. Skinner:

Thank you for your letter of May 16, 2000, requesting our input on how your Agency has been addressing new natural gas-fired electrical generation units, commonly known as "peaker plants", in the Chicago area. We are aware of the increase in applications for these sources in the Midwest, and the significant interest in these projects expressed by citizen and environmental groups, as well as public officials. We at the United States Environmental Protection Agency (U.S. EPA) share many of the same concerns.

In your letter, you discuss how the Prevention of Significant Deterioration (PSD) permitting program may apply to these peaker plants, many of which are being permitted at emission levels just below the PSD applicability threshold of 250 tons per year. You are correct that new construction of any kind is evaluated for PSD applicability based on annual potential emissions. The maximum physical capacity of a peaker plant to emit air pollution might not be the same as its "potential to emit". This is because applicants may avoid the requirements of PSD by requesting enforceable emission limits for their projects to ensure the annual emissions do not exceed the respective major source thresholds. We believe that your Agency typically permits these plants appropriately, with emissions limits that can be enforced as a practical matter.

Regarding the stringency of emissions limits on these projects, when Congress established requirements for construction permitting programs, it focused attention on major sources, requiring Best Available Control Technology (BACT) on new and modified major sources. Congress gave State Agencies substantial discretion in how they treat minor sources. Although States must evaluate minor sources to determine whether they will interfere with attainment of the National Ambient Air Quality Standards (NAAQS), there is no specific control technology requirement for minor sources in the Clean Air Act or U.S. EPA regulations. Minor sources subject to Illinois current State Implementation Plan (SIP) need not apply BACT.

Your letter also raises concerns that these sources will operate primarily in the summer. We understand that your Agency will soon be submitting a plan which will demonstrate how selected emissions management strategies will enable Chicago to attain the ozone standard within the required time frames. When our office reviews this demonstration, we will look for evidence that the size of the total nitrogen oxides (NOx) emissions inventory will not compromise the effectiveness of these strategies. We hope, as you do, that the forthcoming restrictions on statewide sources of NOx will make great strides toward this goal.

Also regarding summertime NOx emissions, the Illinois Environmental Protection Agency assures protection of the NAAQS by including short term, hourly emissions limits in its permits. This practice is consistent with the Illinois SIP, at 35 IAC 201.160, requiring applicants to submit proof that their project will not cause a violation of the Illinois Environmental Protection Act. One tool that applicants may use to submit this proof is dispersion modeling. You are to be commended for requesting that dispersion modeling be included for these minor sources as a means to quantify the potential impacts of NOx, and to set suitable hourly and other short term limits as a result.

We hope this letter addresses your concerns, and we would like to offer two additional thoughts. First, after applicants receive their initial permits to operate these peaker plants, some may submit subsequent applications to construct new units or expand operation of their existing units. Certain changes may bring potential emissions above major source thresholds, and consequently may cause either the new project or the entire source to be subject to PSD, including any applicable BACT analyses. one example of this type of change is a request to relax a previously imposed limit such as operating hours. Another example is a proposal to install additional capacity, where such expanded operation was anticipated as part of the original design. We encourage your staff to inform applicants of these consequences and regularly assess the relationship between requested changes to an existing plant and the initially permitted project.

Secondly, we encourage your Agency to continue to solicit public comments and conduct public hearings on these projects. This valuable process allows the people of Illinois to gain a full and meaningful understanding of your analysis of these projects.

We appreciate this opportunity to address your concerns. If you wish to discuss any of these issues further, feel free to call me, or Lauren Steele, of my staff, at (312) 353-5069.

Sincerely,

Francis X. Lyons
Regional Administrator

EPA453/R-93-007

Alternative Control Techniques Document-- NOx Emissions from Stationary Gas Turbines

Emissions Standards Division

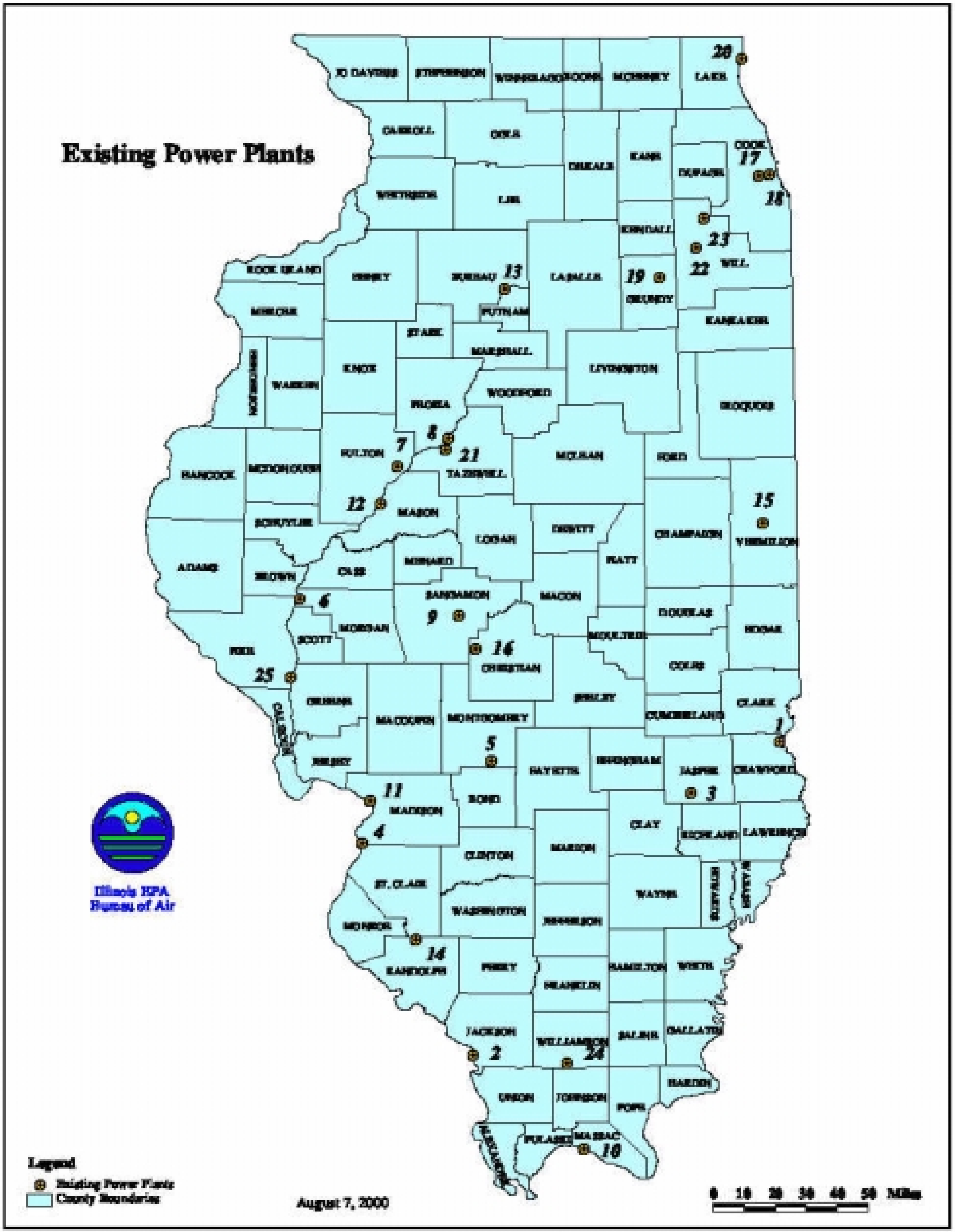
Due to the length of this document (399 pages), it has not been included in this exhibit file.

This document is available online from U.S. EPA at:

http://www.epa.gov/ttn/catc/dir1/gasturb.pdf

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
January 1993

Illinois EPA
Exhibit No. 4


Existing Power Plants
JO DAVIESS
STEPHENSON
WINNEBAGO
BOONE
MCHENRY
LAKE
CARROLL
OGLE
DEKALB
KANE
COOK
DUPAGE
WHITESIDE
LEE
KENDALL
WILL
ROCK ISLAND
HENRY
BUREAU
PUTNAM
LASALLE
GRUNDY
MERCER
STARK
KANKAKEE
MARSHALL
KNOX
LIVINGSTON
HENDERSON
WARREN
WOODFORD
PEORIA
IROQUOIS
FULTON
TAZEWELL
MCLEAN
FORD
HANCOCK
MCDONOUGH
MASON
SCHUYLER
DEWITT
CHAMPAIGN
VERMILION
LOGAN
ADAMS
BROWN
CASS
MENARD
PIATT
SANGAMON
MACON
MORGAN
SCOTT
DOUGLAS
EDGAR
MOULTRIE
PIKE
CHRISTIAN
COLES
GREENE
SHELBY
CLARK
CALHOUN
MACOUPIN
MONTGOMERY
CUMBERLAND
JERSEY
FAYETTE
EFFINGHAM
JASPER
CRAWFORD
MADISON
BOND
CLAY
RICHLAND
LAWRENCE
CLINTON
MARION
ST. CLAIR
WAYNE
EDWARDS
WABASH
WASHINGTON
JEFFERSON
MONROE
RANDOLPH
PERRY
FRANKLIN
HAMILTON
WHITE
JACKSON
WILLIAMSON
SALINE
GALLATIN
HARDIN
UNION
JOHNSON
POPE
PULASKI
MASSAC
ALEXANDER
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
Illinois EPA
Bureau of Air
Legend
Existing Power Plants
County Boundaries
August 7, 2000
0 10 20 30 40 50 Miles

Existing Boiler Power Plants (8/7/00)

MAP NUMBER	ID NUMBER	NAME	COUNTY	STREET ADD	CITY TOWN	FUEL	UTM EAST
1	033801AAA	Hutsonville (Ameren)	Crawford	14281 E 1900th Av	Hutsonvill	Coal boilers	442498.9 4
2	077806AAA	Grand Tower (Ameren)	Jackson	Ferry Rd	Grand Towe	Coal boilers	278413.4
3	079808AAA	Newton (Ameren)	Jasper	6725 N 500th Rd	Newton	Coal boilers	395503.4
4	119105AAA	Venice (Ameren)	Madison	701 Main St	Venice	Gas/oil boilers	745681.3
5	135803AAA	Coffeen (Ameren)	Montgomer	134 CIPS Lane	Coffeen	Coal boilers	292044.9
a	137805AAA	Meredosia (Ameren)	Morgan	800 S Washington St.	Meredosia	Coal & oil boilers	708571.3
7	057801AAA	Duck Creek (Central Illinois Light)	Fulton	17751 N Cilco Rd	Canton	Coal boilers	247925.5
a	143805AAG	E. D. Edwards (Central Illinois Light)	Peoria	7800 CILCO Lane	Bartonvill	Coal boilers	274651.8
9	167120AAO	Lakeside/Dallman (CWLP)	Sangamon	3100 Stevenson Drive	Springfiel	Coal boilers	277154.9
10	127855AAC	Electric Energy	Massac	2100 Portland	Joppa	Coal boilers	334996.3
11	119020AAE	Wood River (IP)	Madison	I Chessen Lane	East Alton	Coal boilers	748805.5
12	125804AAB	Havana (IP)	Mason	N Highway 78	Havana	Coal & oil boilers	748460.9
13	155010AAA	Hennepin (IP)	Putnam	Rural Route	Hennepin	Coal boilers	305886.4
14	157851AAA	Baldwin (IP)	Randolph	10901 Baldwin Rd	Baldwin	Coal boilers	249933.2
15	183814AAA	Vermilion (IP)	Vermilion	Power Plant Rd	Oakwood	Coal boilers	436712.4
16	021814AAB	Kincaid Generation	Christian	Route 104 West	Kincaid	Coal boilers	285467.4
17	031600AIN	Crawford (Midwest Generation)	Cook	3501 S. Pulaski Rd	Chicago	Coal boilers	439978.8
Is	031600AMI	Fisk (Midwest Generation)	Cook	1111 W Cermak Rd	Chicago	Coal boilers	445750.6
19	063806AAF	Collins (Midwest Generation)	Grundy	4200 E Pine Bluff Rd	Morris	Gas/oil boilers	386926.6
20	097190AAC	Waukegan (Midwest Generation)	Lake	401 E Greenwood Ave.	Waukegan	Coal boilers	433310.2
21	179801AAA	Powerton (Midwest Generation)	Tazewell	13082 E Manito Rd	Pekin	Coal boilers	273149.6
22	197809AAO	Joliet (Midwest Generation)	Will	1601 S Patterson	Joliet	Coal boilers	406601.5
23	197810AAK	Will County (Midwest Generation)	Will	529 E Romeoville Rd	Romeoville	Coal boilers	411386.5
24	199856AAC	Southern Illinois Coop	Williamso	10825 Lake of Egypt Rd	Marion	Coal boilers	3
25	149817AAB	Pearl (Soyland Power Coop)	Pike	South Highway 100	Pearl	Coal boilers	705250.8

Existing Boiler Power Plants (8/7/00)

MAP NUMBER	ID NUMBER	NAME	COUNTY	STREET ADD	CITY TOWN	FUEL	UTM EASTING !'UTM NORTHING	
1	033801AAA	Hutsonville (Ameren)	Crawford	14281 E 1900th Av	Hutsonvill	Coal boilers	442498.9 4331575.3	
2	077806AAA	Grand Tower (Ameren)	Jackson	Ferry Rd	Grand Towe	Coal boilers	278413.4	4170609.6
3	079808AAA	Newton (Ameren)	Jasper	6725 N 500th Rd	Newton	Coal boilers	395503.4	4305976.9
4	119105AAA	Venice (Ameren)	Madison	701 Main St	Venice	Gas/oil boilers	745681.3	4283086.4
5	135803AAA	Coffeen (Ameren)	Montgomer	134 CIPS Lane	Coffeen	Coal boilers	292044.9	4325821.7
a	137805AAA	Meredosia (Ameren)	Morgan	800 S Washington St.	Meredosia	Coal & oil boilers	708571.3	4410688.5
7	057801AAA	Duck Creek (Central Illinois Light)	Fulton	17751 N Cilco Rd	Canton	Coal boilers	247925.5	4482695.1
a	143805AAG	E. D. Edwards (Central Illinois Light)	Peoria	7800 CILCO Lane	Bartonvill	Coal boilers	274651.8	4497090.2
9	167120AAO	Lakeside/Dallman (CWLP)	Sangamon	3100 Stevenson Drive	Springfiel	Coal boilers	277154.9	4403468.3
10	127855AAC	Electric Energy	Massac	2100 Portland	Joppa	Coal boilers	334996.3	4119492.0
11	119020AAE	Wood River (IP)	Madison	I Chessen Lane	East Alton	Coal boilers	748805.5	4305373.1
12	125804AAB	Havana (IP)	Mason	N Highway 78	Havana	Coal & oil boilers	748460.9	4462712.1
13	155010AAA	Hennepin (IP)	Putnam	Rural Route	Hennepin	Coal boilers	305886.4	4574644.9
14	157851AAA	Baldwin (IP)	Randolph	10901 Baldwin Rd	Baldwin	Coal boilers	249933.2	4232179.8
15	183814AAA	Vermilion (IP)	Vermilion	Power Plant Rd	Oakwood	Coal boilers	436712.4	4447574.4
16	021814AAB	Kincaid Generation	Christian	Route 104 West	Kincaid	Coal boilers	285467.4	4385488.1
17	031600AIN	Crawford (Midwest Generation)	Cook	3501 S. Pulaski Rd	Chicago	Coal boilers	439978.8	4630755.7
Is	031600AMI	Fisk (Midwest Generation)	Cook	1111 W Cermak Rd	Chicago	Coal boilers	445750.6	4631357.2
19	063806AAF	Collins (Midwest Generation)	Grundy	4200 E Pine Bluff Rd	Morris	Gas/oil boilers	386926.6	4V8588.7
20	097190AAC	Waukegan (Midwest Generation)	Lake	401 E Greenwood Ave.	Waukegan	Coal boilers	433310.2	4692596.0
21	179801AAA	Powerton (Midwest Generation)	Tazewell	13082 E Manito Rd	Pekin	Coal boilers	273149.6	4491024.2
22	197809AAO	Joliet (Midwest Generation)	Will	1601 S Patterson	Joliet	Coal boilers	406601.5	4593915.5
23	197810AAK	Will County (Midwest Generation)	Will	529 E Romeoville Rd	Romeoville	Coal boilers	411386.5	4609585.6
24	199856AAC	Southern Illinois Coop	Williamso	10825 Lake of Egypt Rd	Marion	Coal boilers	3	4165199.7
25	149817AAB	Pearl (Soyland Power Coop)	Pike	South Highway 100	Pearl	Coal boilers	705250.8	4369098.7

Table 1: Existing Fossil-Fuel Fired Electric Utility Boilers

Operation: All Coal-fired boilers are base-loaded except at Havana which is cyclic and all Gas/oil-fired boilers operate as Peakers except Collins 1-5 which are cyclic units

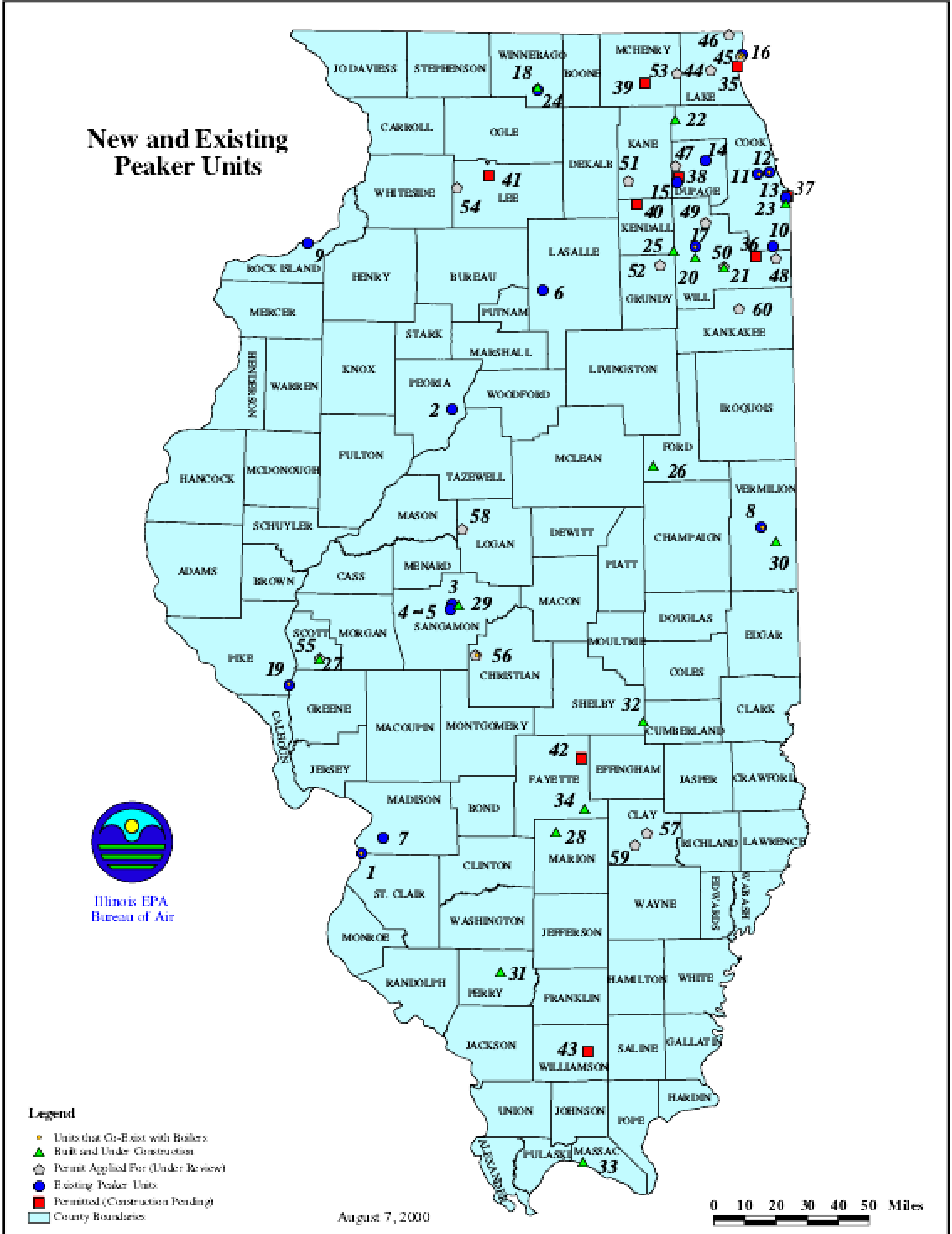
Acid Rain NOx Limits (lb/mmBtu): T-fired Boilers: 0.45 (Ph. 1), 0.40 (Ph.11); W-Fired Units: 0.50 (Ph. 1). 0.46 (Ph. 11). C-Fired Units >155 MW (0.86). Soyland Power <25 MW and hence no NOx limit.

Abbreviations: C- Cyclone; T- Tangential; W- Wall; Cty - County; A.R - Acid Rain; NAA - Non. Attainment Area

F: qprof EGU-nu-old Peakersl.xls/ 8-15-2000 Original in F:wp/existing power plants2.xis/sheeti/ 8-7-2000

Company Name UnitName	Street Address	City/ Town	County	ID No.	Area Designation	Primary Fuel	No. of Boilers	Type of Boller	Total MW	A.Rain Nox Control Applicability	1998 Nox Emissions TonslYr
Midwest Generation (Com Ed)											
Crawford 7,8	3501 S. Pulaski Rd	Chicago	Cook	031600AIN	Chicago NAA	Coal	2	2-T	542	Yes	4778
		Chicago	Cook	031600AMI	Chicago NAA	Coal	I	I-T	321	Yes	3,095
		Morris	Grundy	063806AAF	Chicago NAA	Coal	5	&V	2794	Yes	4019
. rw kegan 6,7.8 401 E Greenwood Ave		Waukegan	Lake	097190AAC	AA Chicago NAA AA	Coal	3	I-C, 2-T	790	Unit 6-No, 7& 8-yes	9627
		Joliet	will	197809AAO	Chica goN A	Coal	5	1 -C, 2-T	1328	Yes	18565
							4	2-C, 2- T	1094	Yes	12659
Dynegy Midwest Group (1P)											
Wood River 4,5							2	2-T	501	Yes	6496
Wood River 1-3	1 Chessen Lane	Cast Alton	M dison	119020AAE	Metro East NAA	Gas/oil	3	3	153	No	87
[H.l.onville 3,4	14281 E 1900th Ave	Venice Hutsonville	Madison Crawford	119105AAA 033801AAA	Metro East NAA Downstate Cly	Gas/oil Coal	a 2	8 2-T	474 150	No Yes	180 1283
,Grand Tower 7,8	Ferry Rd	Grand Tower	Jackson	077806AAA	Downstate Cty	Coal	3	3-W	177	Yes	2080
INew1on 1,2	6725 N 500th Rd	~ewton	Jasper	079808AAA	Downstate Cly	Coal	2	2-T	1267	Yes	8778
Imereclosia 1,2,3 ~e2ta 4 M r _	800 S Washington St 800 S Washington St	Coffeen Mereclosia Meredosia	Morgan Morgan Nontgomor	135803AAA 137805AAA 137805AAA	Downstate Cty Downstate Cty Downstate Cty	Coal Coal Gas/oil	2 5 1	2-C 5-T 1	1005 355 210	Yes- Yes No	24813 3248 3 139 1 9
AES C/o CILCO											r3l
		Canton	Fulton	057801AAA	Downstate Cty	Coal	I	1-W	416	Yes	5 6 7156 7
			Peo, eoria	14380SAAG	Downstate Cty	Coal	3	3-W	786.5	Yes	10003 3 0 0 0
rLakeside 7,8; Dallman 1-2 13100 Stevenson Drive		Spqingfield	Sangamon	167120AAO	Downstate Cty	Coal	4	4-C	235	No	6366
							11	11-T	200	Yes	2249
Joppa 1-6	2100 Portland	Joppa	Massac	127855AAC	Downstate Cty	Coal	6	6-T	1086	Yes	9509
Dynegy Midwest Group (1P)											
Havana 6	N Highway 78	Havana	Mason	125804AAB	Downstate Cly	Coal	I	I-W	429	Yes	1 5 4
Havana 1-5	N Highway 78	Havana	Mason	125804AAB	Downstate Cty	Gastoil	a	8	230	No	244
Hennepin 1,2	Rural Route	Hennepin	Putnam	155010AAA	Downstate Cty	Coal	2	2-T	300	Yes	5111
		Baldwin	Randolph	157851AAA	Downstate Cly	Coal	3	2-C, 1-T	1774	Yes	62711
		Oakwood	Vermilion	183814AAA	Downstate Cly	Coal	2	2-T	177	Yes	1980
		Kincaid	Christian	021814AAB	Downstate Cty	Coal	2	2-C	1108	Yes	32534
Pcywerton 5,6	13082 E Manito Rd	Pekin	Tazewell	179801AAA	Downstate Cty	Coal	4	4-C	1598	Yes	33633
SIPCO											
IMarion 1-4 ISoyland Power Coop	10825 Lake of Egypt Rd	Marion	Williamson	199856AAC	Downstate Cty	Coal	4	4-C	272	1.2,3 -No/ 4-yes	11731
Soyland	South Highway 100	Pearl	Pike	149817AAB	Downstate Cty	Coal	I	I-W	24	No	749.9
Total							90		19,797		288,139

Illinois EPA
Exhibit No. 6


New and Existing Peaker Units
JO DAVIESS
STEPHENSON
WINNEBAGO
BOONE
MCHENRY
LAKE
CARROLL
OGLE
DEKALB
KANE
COOK
DUPAGE
WHITESIDE
LEE
KENDALL
ROCK ISLAND
HENRY
BUREAU
LASALLE
GRUNDY
WILL
MERCER
PUTNAM
STARK
KANKAKEE
HENDERSON
WARREN
KNOX
MARSHALL
LIVINGSTON
PEORIA
WOODFORD
IROQUOIS
FORD
HANCOCK
MCDONOUGH
FULTON
TAZEWELL
MCLEAN
VERMILION
SCHUYLER
MASON
LOGAN
DEWITT
CHAMPAIGN
ADAMS
BROWN
CASS
MENARD
PIATT
MACON
SCOTT
MORGAN
SANGAMON
DOUGLAS
EDGAR
MOULTRIE
PIKE
CHRISTIAN
COLES
SHELBY
CLARK
CUMBERLAND
GREENE
MACOUPIN
MONTGOMERY
CALHOUN
JERSEY
FAYETTE
EFFINGHAM
JASPER
CRAWFORD
MADISON
BOND
CLAY
RICHLAND
LAWRENCE
MARION
CLINTON
ST. CLAIR
WAYNE
EDWARDS
WABASH
WASHINGTON
JEFFERSON
MONROE
RANDOLPH
PERRY
FRANKLIN
HAMILTON
WHITE
JACKSON
WILLIAMSON
SALINE
GALLATIN
UNION
JOHNSON
POPE
HARDIN
ALEXANDER
PULASKI
MASSAC
Illinois EPA
Bureau of Air
Legend
Units that Co-Exist with Boilers
Built and Under Construction
Permit Applied For (Under Review)
Existing Peaker Units
Permitted (Construction Pending)
County Boundaries
August 7, 2000
0 10 20 30 40 50 Miles

New and Existing Peaker Units (8/7/00)

MAP-NUMBER	ID-NUMBER	NAME	CITY-TOWN	UTM EASTING	UTM NORTHING
1	119105AAA	Venice (Ameren)		745681.3	4283086.4
2	143065AMW	Sterling Ave (Central Illinois Light)	Peoria	277836.4	4513075.8
3	167120AGQ	Factory Street (CWLP)	Springfield	274942.7	4411680.3
4	167120AHJ	Reynolds Street (CWLP)	Springfield	273820.3	4409338.9
5	167120AHJ	Ridgely Road (CWLP)	Springfield	273820.3	4409338.9
6	099816AAB	Oglesby (IP)	Oglesby	326214.2	4573401.9
7	119813AAC	Stallings (IP)	Stallings	756778.1	4290905.2
8	183814AAA	Vermilion (IP)		436712.4	4447574.4
9	161045AAV	Moline (Midamerican Energy)	Rock Island	705879.1	4598058.3
10	031045AAR	Bloom (Midwest Generation)	Chicago Heights	446760.6	4593291.8
11	031600AIN	Crawford (Midwest Generation)		439978.8	4630755.7
12	031600AMI	Fisk (Midwest Generation)		445750.6	4631357.2
13	031600AW	Calumet (Midwest Generation)	Chicago	454662.8	4618156.6
14	043804AAA	Lombard (Midwest Generation)	Lombard	413239.1	4638248.6
15	043805AAM	Electric Junction (Midwest Generation)	Eola	397596.6	4627536.6
16	097190AAC	Waukegan (Midwest Generation)		433310.2	4692596.0
17	197809AAO	Joliet (Midwest Generation)		406601.5	4593915.5
18	201030AXQ	Sabrooke (Midwest Generation)	Rockford	327027.5	4677411.6
19	149817AAB	Pearl (Soyland Power Coop)		705250.8	4369098.7
20	197808AAC	Peoples Gas	Elwood	406200.0	4588200.0
21	197811AAH	Desplaines Greenland/Enron	Manhattan	421000.0	4582750.0
22	089425AAC	Dynegy/Rocky Rd	E.Dundee	397560.0	4660075.0
23	031600GHA	Calumet Energy Team LLC	Chicago	453691.0	4614679.0
24	20103OBCG	Indeck-Rockford	Rockford	326506.0	4678385.0
25	093808AAD	LS Power*	Minooka	394944.0	4592616.0
26	053803AAL	Ameren CIPS/LIE	Gibson	381496.0	"80755.0
27	171851AAA	Soyland Power	Alsey	719900.0	4382989.0
28	121803AAA	Ameren CIPS/LIE	Kinmundy	325046.0	4292354.0
29	167822ABG	CWLP	Springfield	278302.0	4411159.0
30	183090AAE	Illinois Power	Tilton	444268.0	4439513.0
31	145842AAA	Ameren CIPS	Pinckneyville	294242.0	4220599.0
32	173801AAA	Reliant Energy/Shelby Energy Center	Sigel	372581.0	4348630.0
33	127899AAA	Electric Energy/Midwest Electric Power	Joppa	334412.0	4120444.0
34	051030AAD	Spectrum Energy	St. Peters	340901.0	4304193.0
35	097125ABT	Unicom/ComEd	N. Chicago	431000.0	4686200.0
36	197899AAB	Univ. Park Energy/ Constellation Power	Univ. Park	437128.0	4587674.0
37	03160OGGV	People's Energy/Calumet Energy	Chicago	454600.0	4618400.0
38	043407AAF	Reliant Energy	Aurora	398188.0	4629793.0
39	11 1805AAP	Reliant Energy	Woodstock	382200.0	4678700.0
40	093801AAN	Kendall New Gent. Dev./En-ron	Yorkville	376500.0	4616500.0
41	103817AAH	Duke Energy/Lee Generating Station	Lee County	300380.0	4633450.0
42	051808AAK	Cent. Energy S C Power/ S	St. Elmo	339258.0	4329660.0
43	199856AAK	Reliant Energy/ Williamson Energy Center	Crab Orchard	339000.0	4177500.0
44	097090ACD	Indeck	Libertyville	416708.0	4685078.0
45	097190AAC	Midwest Generation	Waukegan	432729.0	4691812.0
46	09781 0AAC	North Shore Power/ Carlton Inc.	Zion	426573.0	4703513.0
47	043090ADB	Standard Energy Venture, LLC	W.Chicago	397430.0	4636100.0
48	197030AAO	Power Energy Partners	Crete	448282.0	4586608.0
49	197810ABS	Rolls-Royce/Lockport Power Gen.	Lockport	411907.0	4606375.5
50	19781 1AAH	Enron/Desplaines Green Land Dev.	Manhattan	421000.0	4582750.0
51	089802AAF	Coastal Power Co./Fox River Pkng	Big Rock	372683.0	4628908.0

New and Existing Peaker Units (8/7/00)

52	063800AAP	Kinder Morgan-Aux Sable Power Pit	Morris 387650.0	4584550.0
53	11 1032AAA	Indeck	McHenry County 399020.0	4683730.0
54	1038-1-4-AAC	LS Power*	Lee County 283698.0	4627859.0
55	171851AAA	Soyland Power	AJsey 719900.0	4382989.0
56	021814AAG	Dom. Energy-Lincoln Generation	Kincaid 286613.0	4385075.0
57	025804AAC	Entergy Power-Flora Peaking Station	Flora 372986.0	4290190.0
58	--- 1i07815AAC	Spectrum Energy-Logan County	New Holland 281343.0	4450724.0
59	025803AAD	Aquila Energy/MFP Flora Power	Flora 366035.0	4284314.0
60	091015AAD	Indeck-Bourbonnias Energy Center	Bourbonnias 427760.0	4560799.0

Table 2: Existing Oil/Gas-fired Peaking Power Plants

(DOES NOT INCLUDE MUNICIPAL FACILITIES OTHER THAN CWLP)

F: qpro/ EGU-nu-old Peakersl.xis/ 8-15-2000 Original in F:wp/existing power plants2.xls/sheeti/ 8-7-2000

Emissions are for 1998 reported by the facility

Nox Data as reported by the facilities was provided by Chris Higgins

Company Name UnitName	Street Address	**City/ Town**	**County**	ID No.	Area Designation	**Fossil** Fuel	No. of Turbines	Type of Turbines	Total MW	A. Rain NOx **Control**	1998 Nox Emissions Tons[Yr
Midwest Generation											
Bloom Peakers	W 135th St	Chicago Heights	Cook	031045AAR	Chicago NAA	Diesel	5	Simple	64	None	22.6
Crawford Peakers	3501 S. Pulaski Rd	Chicago	Cook	031600AIN	Chicago NAA	Oil/Gas	12	Simple	149	None	1.0
Fisk Diesel Peakers	1111 W Cermak Rd	Chicago	Cook	031600AMI	Chicago NAA	Diesel	5	Simple	11	None	0.0
Fisk Peakers	1111 W Cermak Rd	Chicago	Cook	031600AMI	Chicago NAA	OIl/Gas	8	Simple	264	None	172.5
Calumet Peakers	3200 E 100th St	Chicago	Cook	031600AMJ	Chicago NAA	Gas	11	Simple	148	None	81.6
Lombard Peakers	1 N 423 Swift Rd	Lombard	DuPage	043804AAA	Chicago NAA	Oil/Gas	4	Simple	72	None	37.7
Electric Junction Peakers	Diehl & Eola Rds	Eola	DuPage	043805AAM	Chicago NAA	N.Gas	12	Simple	154	None	229.8
Waukegan Peakers	401 E Greenwood Ave	Waukegan	Lake	097190AAC	Chicago NAA	Oil/Gas	4	Simple	144	None	1844.4
Joliet Diesel Peakers	1601 S Patterson	Joliet	Will	197809AAO	Chicago NAA	Diesel	5	Simple	I I	None	12.7
Joliet Peakers	1601 S Patterson	Joliet	Will	197809AAO	Chicago NAA	N.Gas	8	Simple	103	None	1281.9
Ameren											
Standby Turbine	701 Main St	Venice	Madison	119105AAA	Metro East NAA	Oil/Gas	I	Simple	38	None	11.6
Dynegy Midwest Group											
Stallings	Highway 162	Stallings	Madison	119813AAC	Metro East NAA	Oil/Gas	4	Simple	128	None	224.2
Midwest Generation											
Sabrooke Peakers	123 Energy Ave.	Rockford	Winnebago	201030AXQ	Border Area	Oil	7	Simple	143	None	129.6
LaSalle Peakers (Nucl. Plant)	2601 North 21 st Road	Marseiles	LaSalle	099802AAA	Border Area	Oil/Gas	5	Simple	130	None	9.3
AES do CILCO											
Sterling Ave Turbine	N Sterling Ave	Peoria	Peoria	143065AMW	Downstate Cty	Oil/Gas	2	Simple	34	None	17.2
CWLP											
Factory Street #2 Turbine	Factory & Griffith Sts.	Springfield	Sangamon	167120AGQ	Downstate Cty	Gas	I	Simple	28	None	16.4
Reynolds Street Turbine	10th & Reynolds Sts.	Springfield	Sangamon	167120AHJ	Downstate Cty	Gas	I	Simple	22	None	8.5
Dynegy Midwest Group											
Oglesby Turbine	111. Highway 351	Oglesby	LaSalle	099816AAB	Border Area	Gas	I	Simple	18	None	224.6
Vermilion	Power Plant Rd	Oakwood	Vermilion	183814AAA	Downstate Cty	Oil	I	Simple	23	None	3.0
Midamerican Energy											
Moline	2811 Fifth Ave	Rock Island	Rock Island	161045AAV	Downstate Cty	Gas	4	Simple	80	None	19.4
Soyland Power Coop											
Pearl	South Highway 100	Pearl	Pike	149817AAB	Downstate Cty	Oil	I	Simple	22	None	9.7
Total							102		1786		4358

Illinois EPA
Exhibit No. 8

Table 3: New EGU Peaker Units

F: qpro/ EGU-nu-old Peakers.xist 8.15.2000 Original in Rwiplexisting power plants2.xistsheetl/ B-7-2000
Abbreviations: SCT= Simple Combustion Turbine; PSD z Prevention of Significant Deterioration; PSD Minor means emissions are less than the derninimus value; (u) means used turbine relocated from another site
Drv LoNOx = Drv Low NOx Burners: Water Ini. = Water Iniection: N. G. = Natural Gas: Non-N PS means NSPS not applicable because the unit is a used unit told' from another

Sr. No.	Company Name	Location	ID #	Area Designation	No of Units	NOx Control	Turbine Manufact. & Model Number	Total MW	Fuel Type	a Hours of Operation PerYear Per Unit	0 . Total Permitted AnnualNOx TonsfYr.	Nox Rate pprn	NOx Rate lb/mmBtu	Applicable Rule	Bureau of Water Permit
1	2	3	4	1	4	7			lo	I	U	13	14	Is	1.
1	Peoples Gas	Elwood	19780SAAC	ChlcagoNAA	4	Dry LoNOx	GE Frame 7FA	690	N.GA-	1440	292	15	0.061	PSDIBACT	NPOES Under Revl7
		Manhattan	197811AAH	Chicago NAA	8	Dry LoNOx	GE Frame 7FA	664	N.Gas	3250	318	9			
3	[Dynegy/Roc Rd	E.Dundee	08942SAAC	Chicago NAA	4	DLN1W.I.	W. Frame 501 D	398	N.-	1300	249	25(G).42(0)	0.037 0.1 (G)	PSDIBACT NSPS	State 1999-EP-3731
4	Calumet Energy Team LLC	Chicago	031600GHA	Chicago NAA	2	DLN/WI	ABB Frame llN2	305	N.G/ #20il	1500	240	25-g/42-oll		PSD Minor	
6	LS Po"r*	**Rockford** Minooka	20103OBCG 093808AAD	Border County Border Twnshlp	2 4	Dry LoNOx SCR	SW Frame V54	300 1,000	N.Gas N.GJOfl	1176 8760	398 1,604	15 44(0)(SM)	0.0`143	PSD/BACT PSDIBACT	NPDES IL0073806
	LAmeren CIPS/ UE	Gibson	053803AAL	Downstate Cnty	2	Dry LoNOX		270	N.GJDb. co	No Limit	249	25(G),42(6)	o.i (G)	PSD Minor	State 2000-EE-0680
a	Soyland Power-	Alsey	171851AAA	Downstate Cnty	2	Dry LoNOx	W. Fra;; 251 AA (u)	so	WAX! M	23	124	About 175	0.7	Non-NSPS	
1 9 10	Ameren CIPS/ UE CVVLP Illinois Power	Kinmundy Springfield Tifton	121803AAA 167822ABG 183090AAE	Downstate Cnty Downstate Cnty Downstate Cnty	2 I 4	Dry LoNOx Water Inj. Water Inj.	GE Aero LM6000	270 100 I	N.GJM. . ft.o~ G-	No Limit No Limit 2352	249 249 192	25(G).42(0) 75 25	0.1 (G) 0.1	PSD Minor NSPS NSPS	sti9e9+e-3123;2oDo-EE-o7si
12	Anneren CIPS	Pinckneyville	145842AAA	Downstate Cnty	4	Water In).	GE Aero LM6000	194	N.Gas	8736	200	35		NSPS	State 2000-EE-0708
t 3 _L_	Reliant Energy/ Shelby Enrgy Cntr	Sigel	173801AAA	Downstate Cnty	8	Water Ini.	GE Aero LM6000	328	N.Gas	No Limit	198	25	0.09	NSPS	St-2000-EE-5480; 5480-1
14	Electric EnergyrMidwest Elec. Power	Joppa	127""M	2 Danst!j! ~nly	3	Water Ini.		216	N.Gas	5824	251	40		Netted	
15	Spectrum Energy	St. Peters	051030	Cnty	I	Water Inj.		45		2890	86	25	0.10	NSPS	
	Built and Under Construction Total 51 5,006 **4,899**														
	UnicornlComEd IN. Chicago 097127BT JChlcago NAA				2	Dry LoNOx	GE Frame OB	78	N.Gas	No Limit	99	25	0.096	NSPS	
					6	Water Inj.	PW Aero FTS	300	N.Gas	1680	249 -	25		PSD Minor	State 2000-EE-0817
					2	Water Inj.	ABB Frame llN2	266	N.Gas	2000	233	25		NSPS	
					4	Dry LoNOx	GE Frame7FA	Sao	N.Gas	1125	124	15	0.036	NSPS	Under Review
					6	wl	GE Aero LM6000	270	N.Gas	1125	126	9	0.036		
					3	Dry LoNOx	GE Frarne7FA	510	N.Gas	2520	248	9		PSD/BACT	
						Dry LoNOx			Nt.G.10il	32 iloo 00	680	1)	0 117	PSDIBACT _FSDIBACT	
9	Soyland Power**	Alsey	171851	Downstate Cnty	2	Water Inj.	GE Frame LM2500	45	NA V1	560	54		0.7	Non-NSPS	
10	Cent. Enrgy S C Po%,J Spectrum	St. Elmo	051809AAK	Downstate Cnty	1	Water Inj.		45	N.Gas	2890	86	25	0.10	NSPS	
11	Reliant Energy/ Williamson Enrgy Cn	Crab Orchard	199856AAK	Downstate Cnty	8	Water InJ.	GE Aero LM6000	328	N.Gas	No Limit	198	25	0.09	NSPS	
1	**Permitted (Construction Pending)Total** 49 3,850 2,528														
	Indeck Libertyville 097090ACD Chicago NAA 2 Dry LoNOx SW Frame V84.3 300 R.~2000 173 15 0.055 NSPS														
2 1 3	Midwest Generation North Shore P wert Carlton Inc.	Waukegan Zion W.Chicago	097190AAC 09781 OAAC 043090AD8	Chicago NAA Chicago NAA Chicago NAA	2 3 16	Dry LoNOx Dry LoNOx Water Inj.	GE Frame 7FA GEIABB Frame 7FAIIIN2 PW Aero FTS	292 562 800	N.Gas N.GastOil N.Gas	1,307 1180 2500	39 248 1,244	9 25 25	0.091	PSD Minor PSD Minor PSDfBACT	
5	P r Energy Partners	Crete	197030AAO	Chicago NAA	3	Water Inj.	Ass Frame IIIIN2	393	N.Gas	1310	247	25	0.07	PSD Minor	
6	Rolls-RoycefLockport Pwr Gen.	Lockport	197810ABS	Chicago NAA	6	Dry LoNOx	RR Aero Trent (p)	372	N.Gas	No Limit	245	25		PSD Minor	
7	Enron/Desplalnes Green Land Dev.	Manhattan	197511AAH	Chicago NAA	I	Dry LoNOx	GE Frame 7EA	167	N.Gas	2750	115	9		PSD Minor	
8	Coastal Power Coffox River Pkng	Big Rock	089802AAF	Chicago NAA	3	Dry LoNOx	ABB Frames 11N2	345	N.Gas	1425	244	25		PSD Minor	
9	Kinder Morgan-Aux Sable Power Pit	Morris	063800AAP	Chicago NAA	4	Water Inj.	GE Aero LM6000	176	N.Gas	5800	249	25		PSD Minor	
		Holiday Hills	111032AAA	Chicago NAA	2	Dry LoNOx	SW Frame V84	300	N.Gas	2300	log	15	0.0553	NSPS	
12 iytand Power-		**Lee County** Alsey	103814AAC 171851AAA	Border County Downstate Cnty	4 1	SCR Water Inj.	W Frame ACT(u)	1,000 25	N.Gas N.Gas	8760 goo	632 el	4.5 (G) (SCR) 148	0.0143	PSDIBACT iZn-NSPS	NPDES IL0074209
E 3	Dom. Energy-Lincoln Generation	Kincaid	021814AAG	Downstate Cnty	4	Dry LoNOx	GE Frame 7FA	Gas	N.Gas	2500	287	9		PSD/BACT	
	Entergy Power-Flora Peaking Stn	Flora	025804AAC	Do*mstate Cnty	6	Dry LoNOx	GE Frame 7FA	438	N.Gas	1940	249	9-15	0.081	PSD Minor	
1 15	Spectrum Energy-Logan County	New Holland	10781SAAA	Downstate Cnty	3	Water Inj.	GE Frame I-MG000	135	N.Gas	1500	92	25		PSD Minor	
16	Aquila EnergyrMFP Flora Power	Flora	025803AAD	Downstate Cnty	4	Dry LoNOx		378	N.Gas	2100	249	9-15		PSD Minor	
17	Indeck-Bourbormlas Energy Center	Bourbormlas	091015AAD	Downstate Cnty	4 1	Dry LoNOx	GE Frame 7FA	683	N.Gas 1	2000	232	9		PSD Minor	
	Permit Applied For (Under Review) Total 68 7,054 4,803														
	Grand Total 168 15,910 12,230														

Permitted to operate as base load as well as peaker mode.

** Soyland Power has a total of 5 turbines (2 are <5 MW each). Total emissions limited to ~2419 tonstyear

Illinois EPA
Exhibit No. 9

Table 1

National Ambient Air Quality Standards and PSD Increments

Pollutant	Averaging Time	Primary Standard	Class 11 PSD Increments
Particulate Matter (PMIO)	Annual 24-Hour	50 ug/m' 150 ug/m'	17 ug/m3 30 ug/m'
Sulfur Dioxide (S02)	Annual 24-Hour 3-Hour (secondary)	80 ug/m' 365 ug/m' 1,300 ug/m'	20 ug/m' 91 ug/m, 512 Ug/M3
Nitrogen Dioxide (N02)	Annual	100 ug/m,	25 ug/m'
Ozone (03)	I-Hour	0.12 ppm	-----
Carbon Monoxide (CO)	8-Hour I-Hour	10,000 ug/m, 40,000 ug/m'	----- -----

Illinois EPA
Exhibit No. 10

Table 2

Maximum <u>Impact from</u> Peakers Compared to Class II PSD Increments

	Averaging Time	Class 11 PSD Increments	Significant Impact Threshold	Maximum Peaker Impact
	Annual 24-Hour	17 ug/m' 30 Ug/M3	I Ug/M3 5 Ug/M3	2 ug/m' 12 ug/m'
Sulfur Dioxide (S02)	Annual 24-Hour 3-Hour (secondary)	20 ug/m 3 91 Ug/M3 512 Ug/M3	1 Ug/M3 5 Ug/M3 25 Ug/M3	0.1 Ug/M3 5 Ug/M3 13 Ug/M3
-Nitrogen Dioxide (N02)	Annual	25 Ug/M3	1 Ug/M3	5 Ug/M3
Carbon Monoxide (CO)	8-Hour I-Hour	 -----	500 Ug/M3 2,000 Ug/M3	126 Ug/M3 465 Ug/M3

Table 3
Maximum Impact from Peakers Compared to the
National Ambient Air Quality Standards

Pollutant	Averaging Time	Primary Standard	Maximum Peaker Impact	Background Concentration	Total - Concentration]
Particulate Matter (PM10)	Annual	50 Ug/M3	2 Ug/M3	40 Ug/M3	42 ug/m'
	24-Hour	150 Ug/M3	12 ug/m'	130 Ug/M3	142 ug/m'
Sulfur Dioxide (S02)	Annual	80 ug/M3	0.1 Ug/M3	24 ug/in'	24.1 ug/m'
	24-Hour	365 Ug/M3	5 ug/m'	157 Ug/M3	162 Ug/M3
	3-Hour (secondary)	1,300 Ug/M3	13 Ug/M3	440 Ug/M3	453 Ug/M3
Nitrogen Dioxide (N02)	Annual	100 Ug/M3	5 Ug/M3	58 Ug/M3	63 Ug/M3
Carbon Monoxide (CO)	8-Hour	10,000 Ug/M3	126 Ug/M3	5828 Ug/M3	5954 Ug/M3
	I -Hour	40,000 Ug/M3	465 Ug/M3	7771 Ug/M3	8236 Ug/M3

Figure 1 - Significant Impact Area from a Large Peaker Plant for NOx

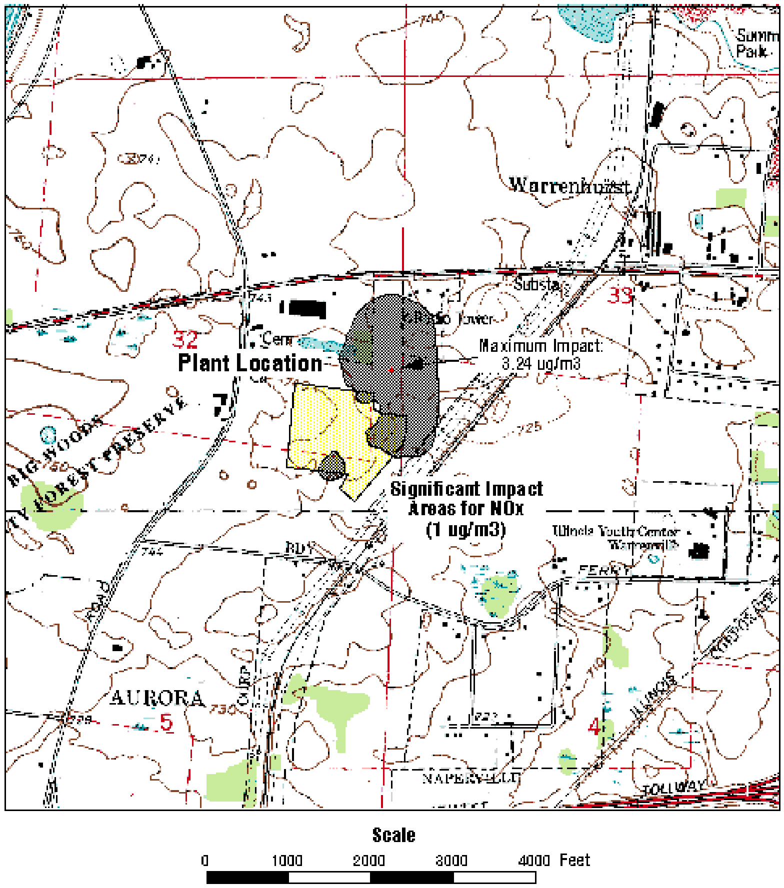


Figure 2 - Impact Area from a Large Peaker Plant for CO

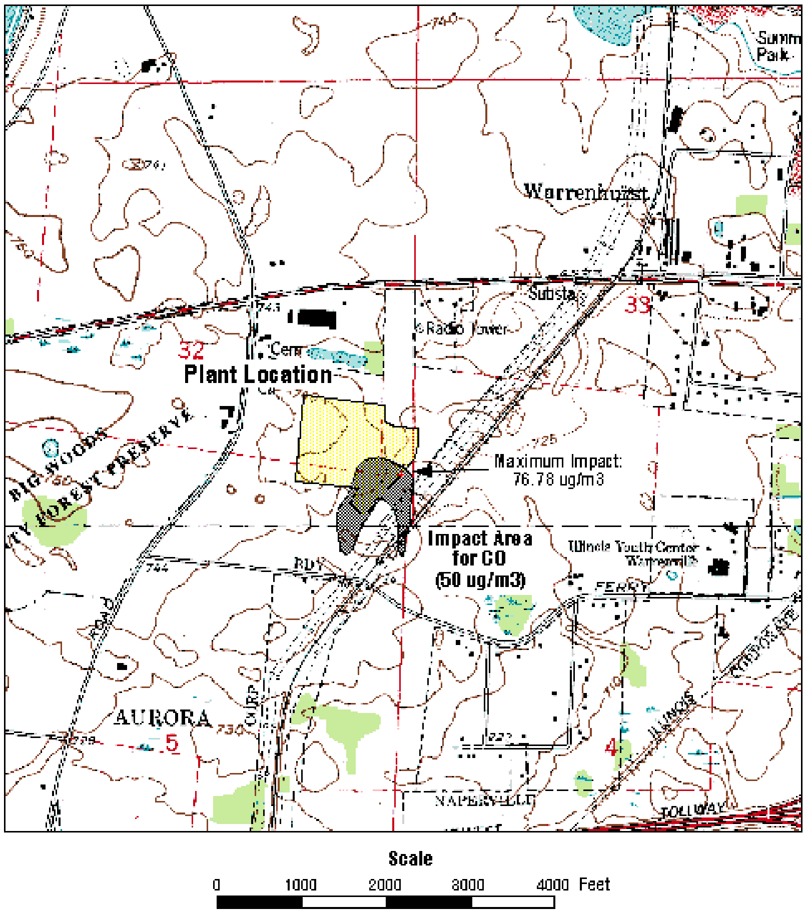


Figure 3 - Impact Area from a Large Peaker Plant for PM10

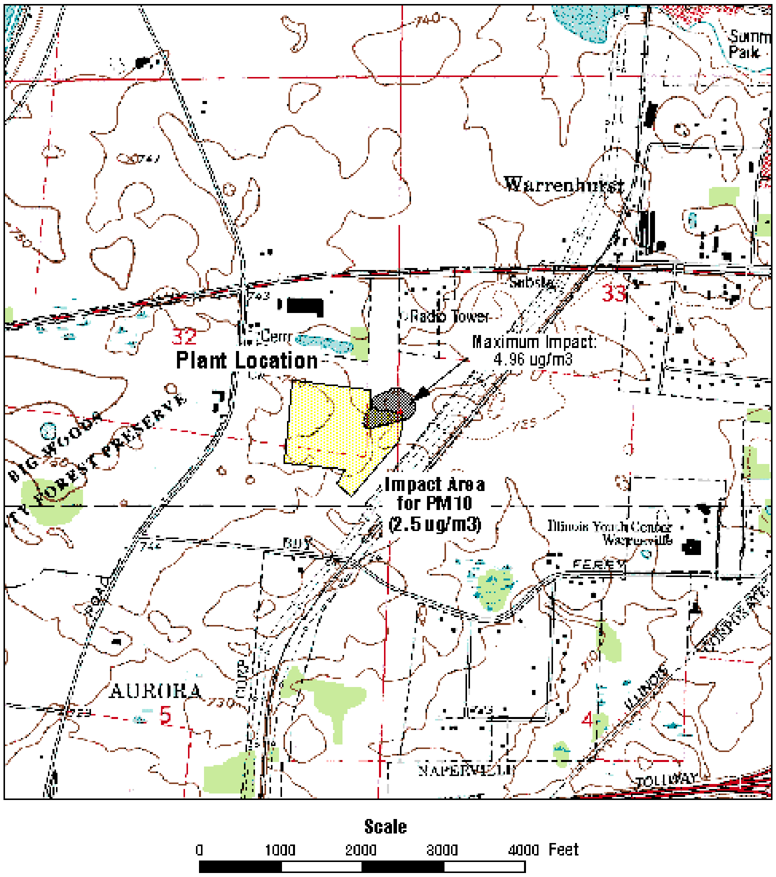


Figure 4 - Impact Area from a Large Peaker Plant for SO2

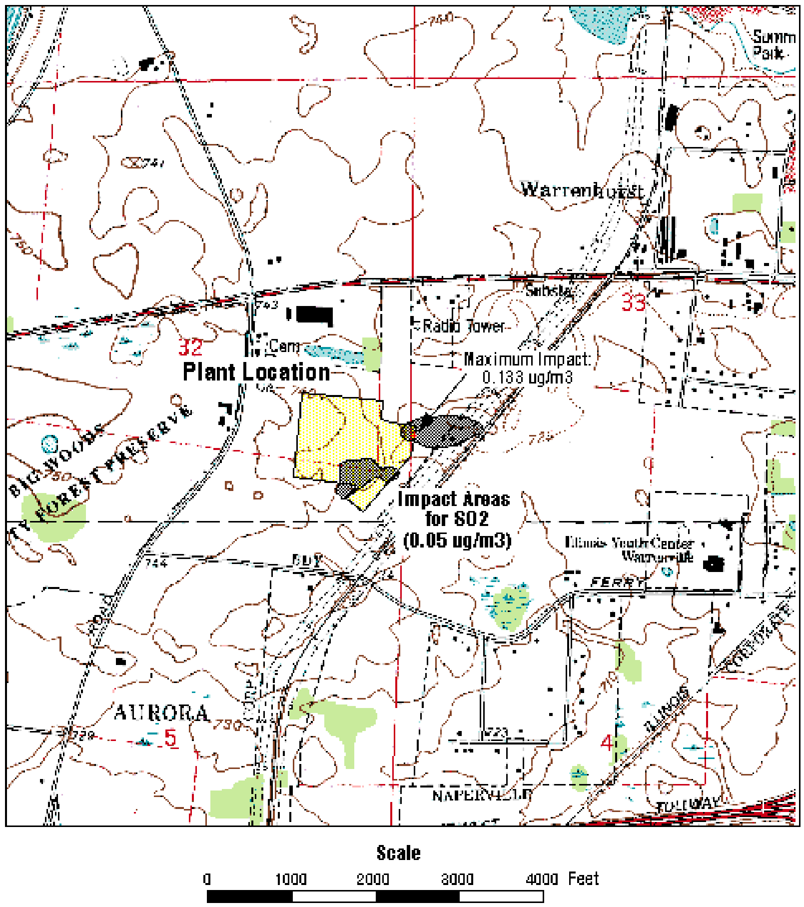
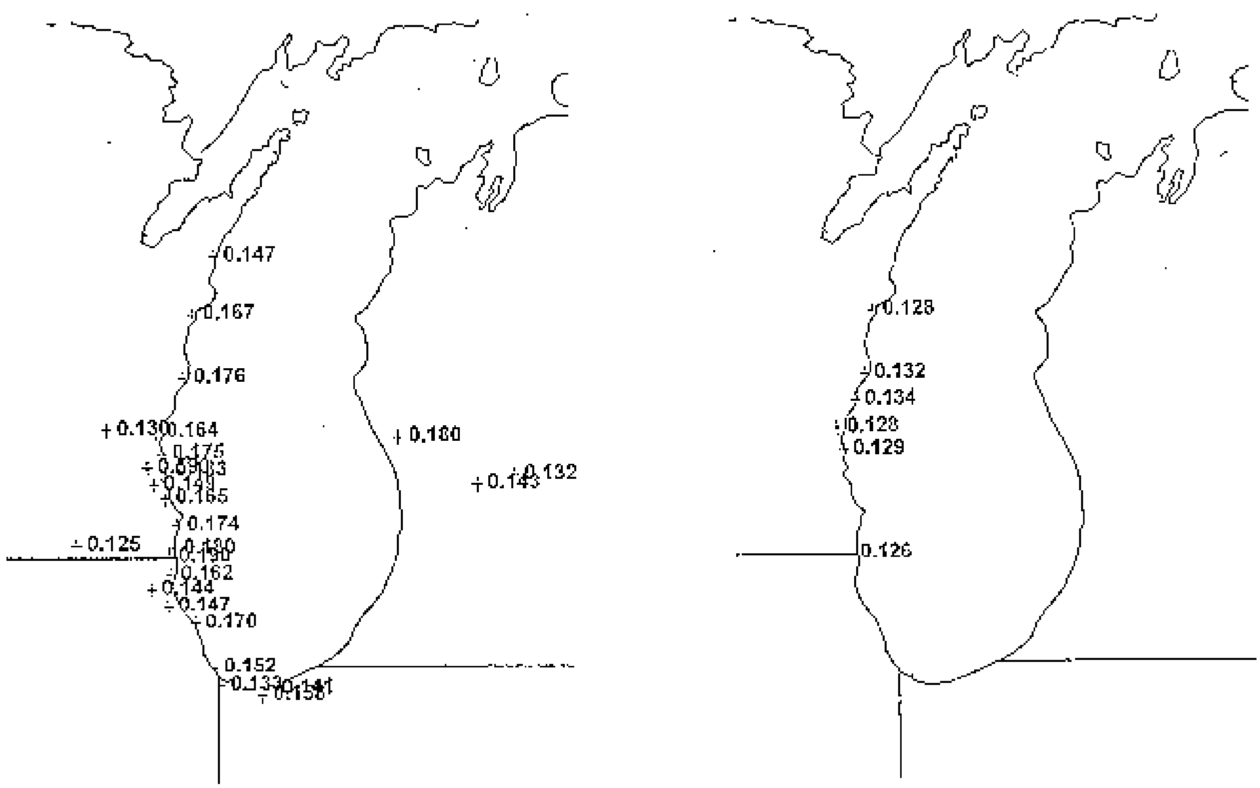


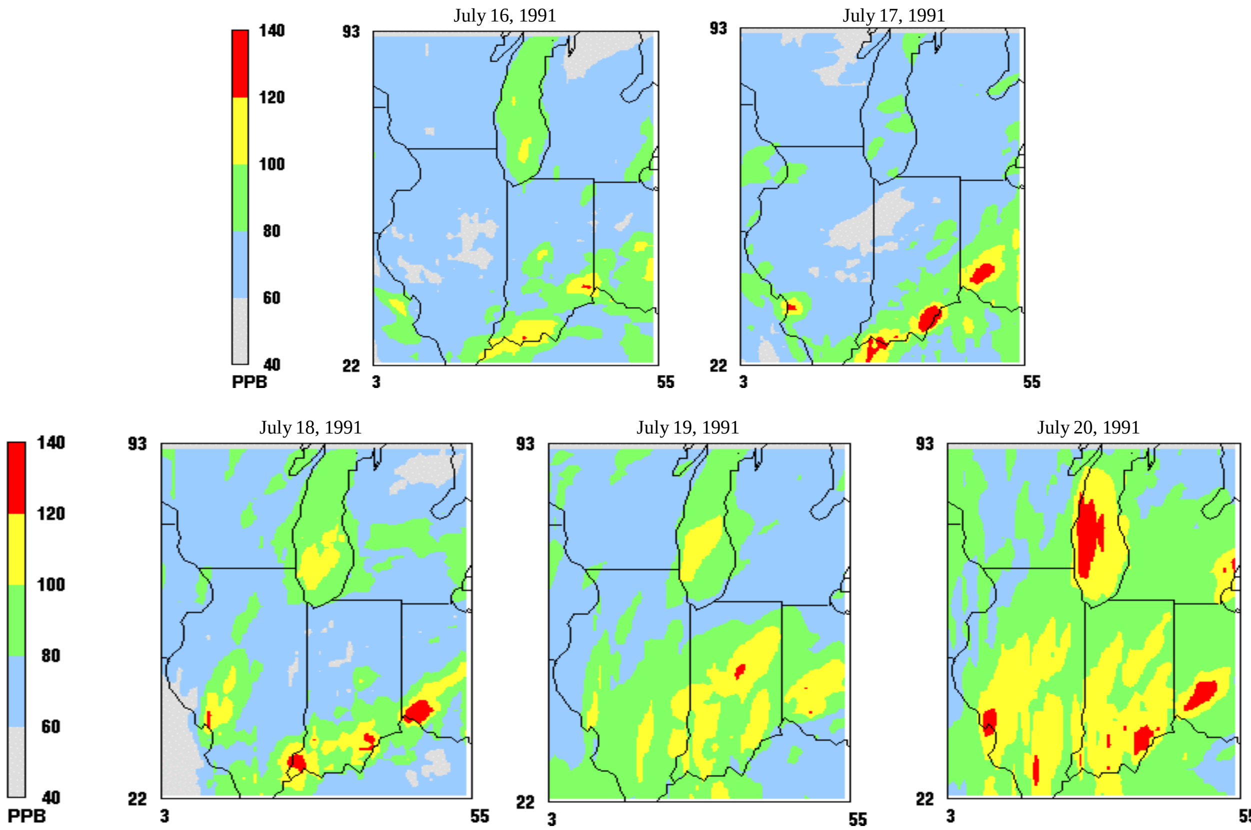
Figure 5

10 Year Trend of 1-Hour Ozone Design Values in the Lake Michigan Area

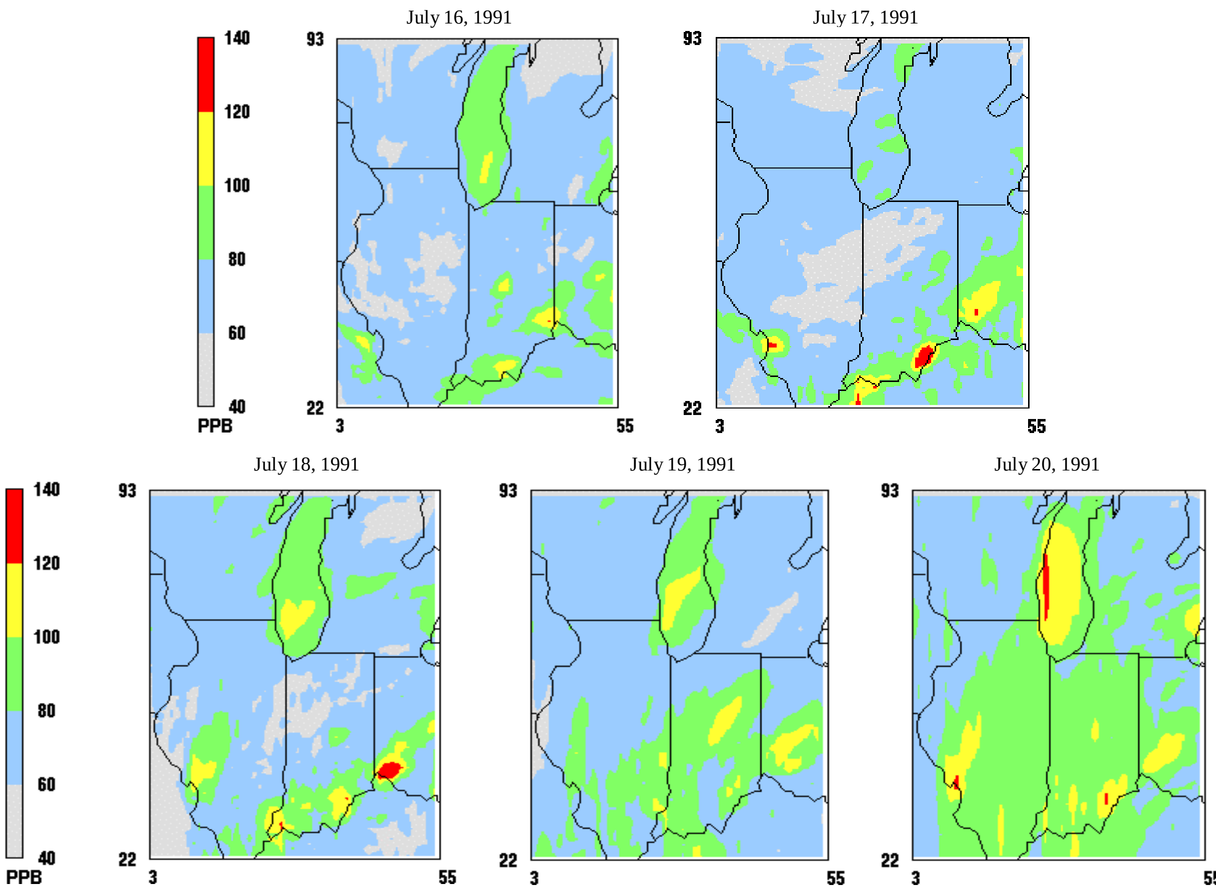
1987 – 1989 | 1997 – 1999



IEPA Exhibit 13
Peak 1-Hour Ozone Concentrations Assuming CAA Controls

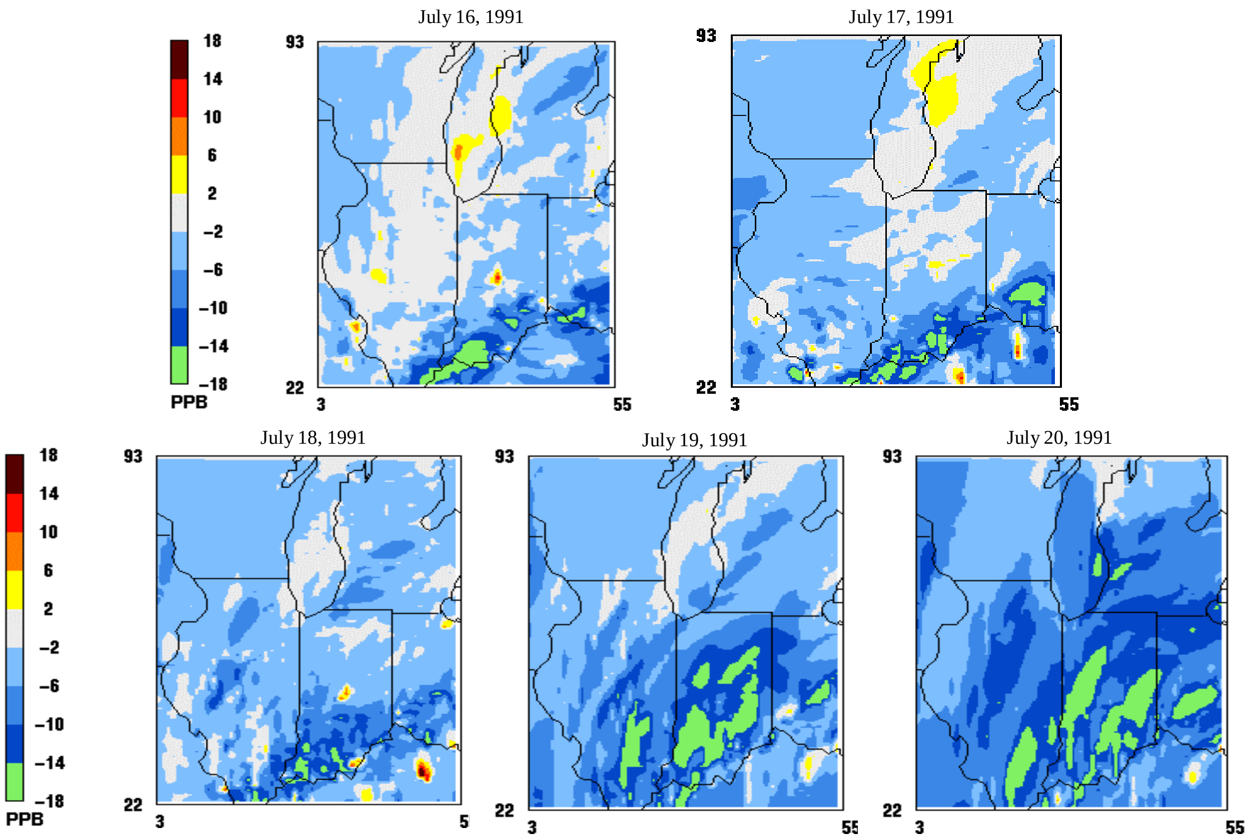


IEPA Exhibit 14
Peak 1-Hour Ozone Concentrations Assuming SIP Call Controls



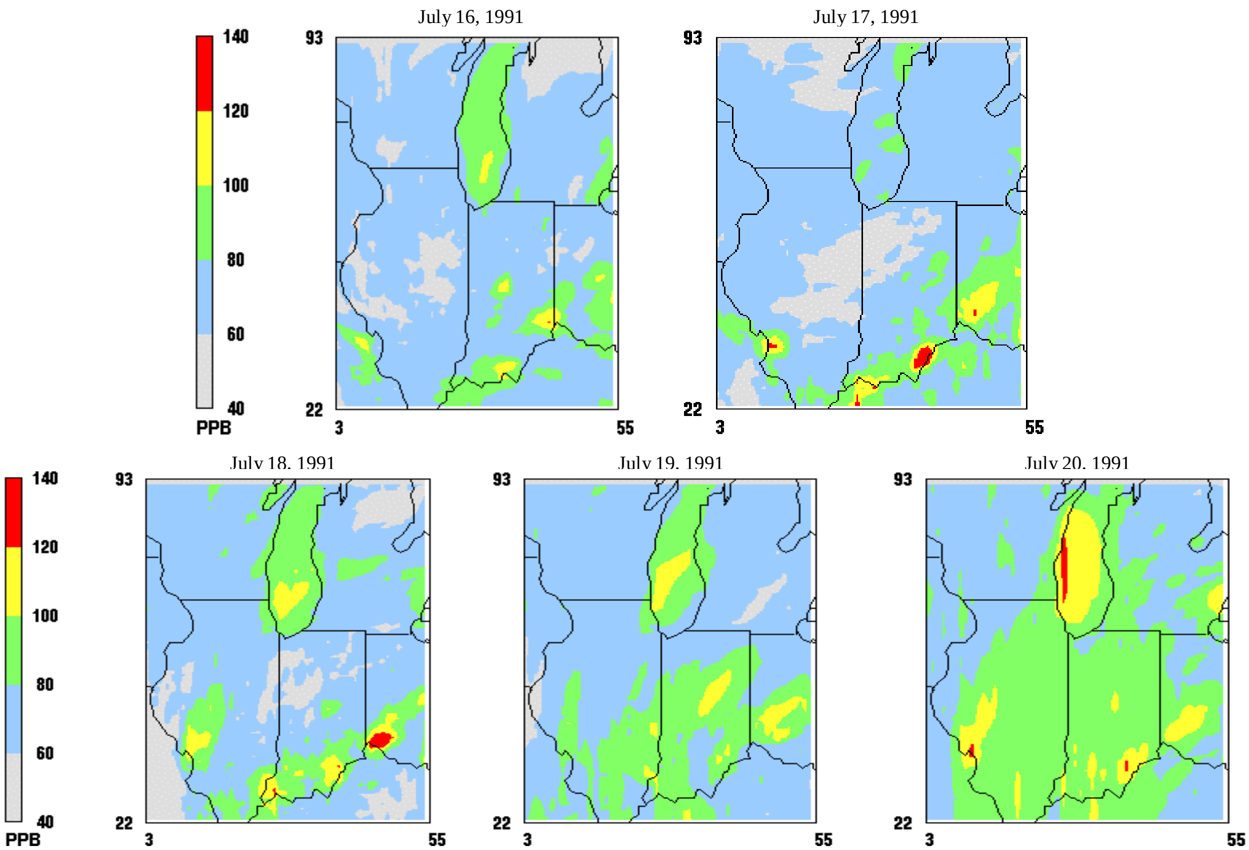
IEPA Exhibit 15

Effect on 2007 CAA Ozone Concentrations due to SIP Call Controls



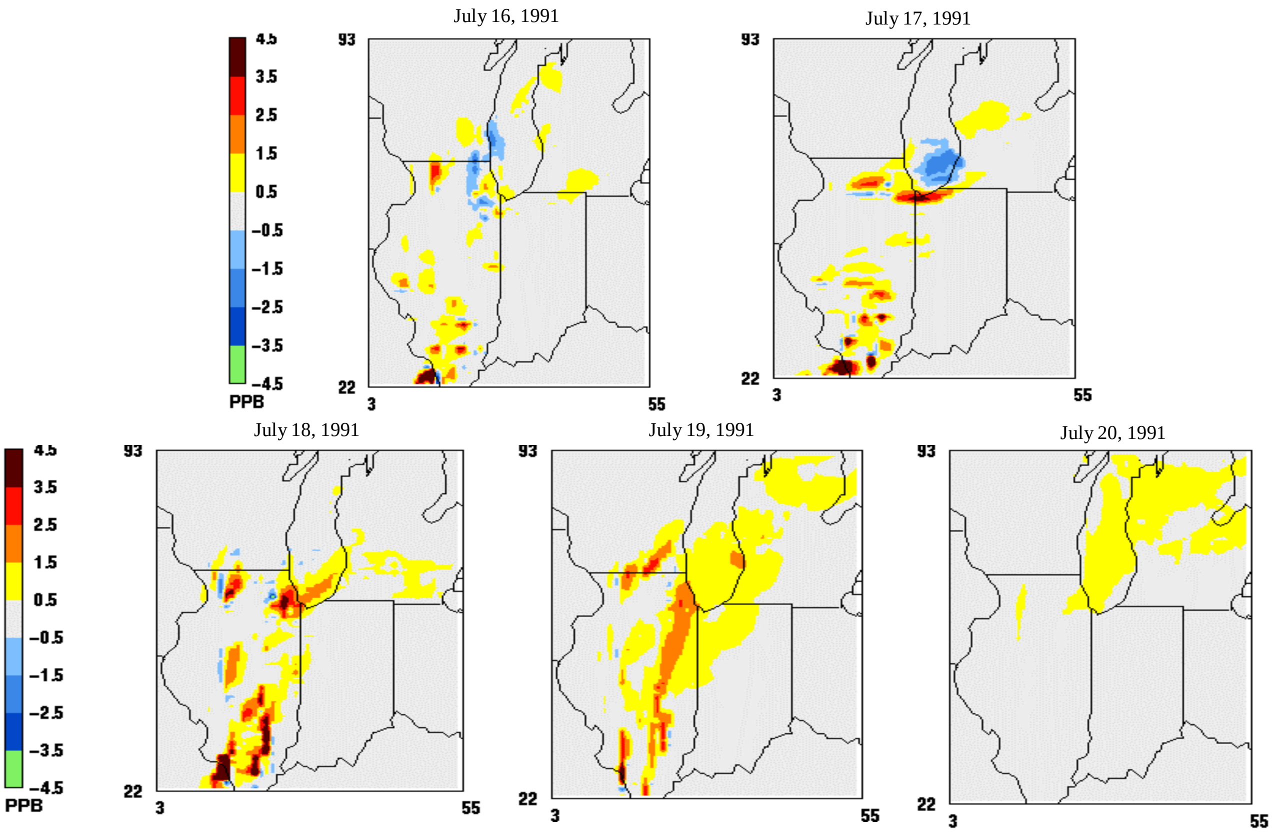
IEPA Exhibit 16

SIP Call 1-Hour Ozone Concentrations with “Peakers”



IEPA Exhibit 17

Effect on SIP Call 1-Hour Ozone from Peakers in Illinois



Overview of Applications for Permits Received by the Illinois EPA's Bureau of Water as of July 20, 2000

Applications received:	8
No. discharging to surface waters:	2
No. discharging to POTW's:	6
Range of flows (gpd):	25,000 to 361,000

Source Water

No. using surface waters:	1
No. using groundwater only:	1

No. using groundwater and/or city water: 3

No. using city water only:	3
Number of permits issued:	5 (POTW Discharge's)

Of the applications received, one facility is located in Ford county, one in Perry county, one in Madison county, one is Shelby county, one in DuPage county, one in Vermilion county, and two are in Will county.

Illinois EPA
Exhibit No. 18

Illinois EPA Exhibit 19

NOISE POLLUTION CLEARINGHOUSE

"Good Neighbors Keep Their Noise to Themselves"

LAW LIBRARY

State Noise Statutes & Regulations

The table below lists which of the fifty states have comprehensive state-wide noise regulations. The table also shows contact information and if the state ofers a model ordinance and/or support to local governments. This survey was compiled in December of 1997. Explanations of the different columns are listed after the survey.

State Noise Regulation Survey

State	State Reg.	Impulse	Model Ordinance	Support	Contact	Phone
AK	NO	NO	NO	NO	Billie Willson	907-465-5061
AL	NO	NO	NO	NO	Blake Roper	1-800-533-2336
AR	NO	NO	NO	NO	NA	501-682-0744
AZ	NO	NO	NO	YES	Fred Garcia	602-255-8639
CA	NO	NO	YES	NO	NA	916-445-3846
CO	NO	NO	NO	NO	NA	303-692-3100
CT	YES*	YES	YES	NO	Joe Pulaski	860-424-3373
DC	YES	NA	NO	NO	James Hauser	202-727-7266
DE	YES*	YES	NO	NO	JoAnna Austin	302-739-4791
FL	NO	NO	NO	NO	Don Trussell	904-488-3601
GA	NO	NO	NO	NO	NA	404-656-4713
HI	YES	YES	NO	YES	James Toma	808-586-4700

Illinois EPA
Exhibit No. 19

IA	NO	NO	N0	NO	Christine Spackman	515-281-8969
ID	NO	NO	NO	NO	NA	208-373-0502
IL	YES	YES	YES	YES	Greg Zak	217-785-7726
IN	NO	NO	NO	NO	Tim Method	317-232-8603
KS	NO	NO	NO	NO	Jan Sides	913-296-1593
KY	YES*	NO	YES	NO	Kenith Hienes	502-564-2150
LA	NO	NO	NO	NO	NA	504-765-0741
MA	YES	NO	NO	NO	NA	617-292-5630
MD	YES	YES	YES	YES	Dave Jarinko	410-333-2590
ME	YES	NO	NO	NO	NA	207-287-3261
MI	NO	NO	NO	NO	NO	517-373-7917
MN	YES	NO	YES	YES	Brain Timerson	612-296-7898
MO	NO	NO	NO	NO	NA	573-751-4422
MS	NO	NO	NO	NO	NA	601-961-5100
MT	NO	NO	NO	NO	NA	406-444-4820
NC	NO	NO	NO	NO	Tom Mather	919-715-7408
ND	NO	NO	YES	NO	Jim Killingbeck	701-328-5150
NE	NO	NO	NO	NO	NA	402-471-2186
NH	NO	NO	NO	NO	NA	603-271-1370
NJ	YES	YES	YES	NO	Eric Zwerling	908-932-8065
NM	NO	NO	NO	NO	NA	505-827-2855
NV	NO	NO	NO	NO	NA	702-687-5065
NY	NO	NO	NO	NO	NA	518-457-7230
OH	NO	NO	NO	NO	NA	614-644-3020
OK	NO	NO	NO	NO	NA	405-271-8056
OR	YES*	NA	YES	NO	Linda Wichart	503-229-5388
PA	NO	NO	NO	NO	NA	717-787-4325
RI	NO	NO	NO	NO	NA	401-277-2771
SC	NO	NO	NO	NO	NA	803-734-4750
SD	NO	NO	NO	NO	Brad Schultz	605-773-3351

	NO	NO	NO	NO	NA	615-241-3600
TX	NO	NO	NO	NO	NA	512-239-3900
UT	NO	NO	NO	NO	NA	801-536-4000
VA	NO	NO	NO	NO	NA	804-698-4020
VT	NO	NO	NO	NO	NA	802-241-3600
WA	YES*	NO	NO	NO	Jerry Lenssen	360-470-6703
WI	NO	NO	NO	NO	Penny Kanable	608-264-8892
WV	NO	NO	NO	NO	NA	304-759-0515
WY	NO	NO	NO	NO	Dan Olson	307-777-7391

*** State has a noise regulation on the books but does not enforce it.**

{short description of image}

Illinois Environmental Protection Agency

Bureau of Air

Fa ct Sheet

May 2000

Peaker Power Plant Fact Sheet

AirFacts

Nationwide, including in Illinois, a number of new natural gas burning power plants are being built and more plants are being proposed. The Illinois EPA has expended significant time and effort over the past eighteen months on the issue of peaker power plants and carefully considers each application. This fact sheet addresses some of the basic questions asked about peaker power plants.

What is a peaker power plant?

New peaker power plants being proposed in Illinois us6 turbines that burn natural gas to produce electricity. They are called peaker power plants because they are generally run only when there is a high demand, known as peak demand, for electricity. In Illinois, this occurs during the summer months when air conditioning load is high, and the nuclear and coal burning power plants cannot meet the demand for power. Peaker plants generally run only during peak periods when utilities will pay higher prices for electricity because it is more expensive to produce electricity by burning natural gas. Peaker power plants cannot compete with the cost of electricity produced by nuclear and coal burning power plants.

Where are these plants being built?

In general, the plants are being located where large capacity power lines and gas pipelines cross or are in close proximity to one another.

Are these faciflliles regulated bv the Illinois EPAP

Yes, the Illinois EPA administers rules that limit the air emissions and, if present, direct water discharges from peaker power plants. The Illinois EPA does not have the authority to consider other issues related to the siting of a proposed facility, (e.g. need for a proposed power plant, aesthetics, etc.) during permitting.

What will be the health impact of a peaker power plant to people living around the facilltvP

The evaluations of new peaker power plants for which the Illinois EPA has received permit applications to date have indicated that the plants will not have a measurable impact on air quality. If a source does not have a measurable impact on air quality, there should not be a health impact. To confirm that proposed plants would not impact air quality, the Illinois EPA has been asking all peaker power plants to submit air quality modeling even though this is not expressly required by the rules for minor sources.

Permit applications are reviewed to determine whether the information presented in the application shows compliance with applicable rules. Permits are prepared with detailed conditions that identify applicable rules and require appropriate testing, monitoring and recordkeeping to verify compliance with applicable rules.

Illinois EPA
Exhibit No.20

These plants will emit almost all of their emissions over a small number of days during the summer. Why can't they be considered malor sources under the federal Prevention of Sionificaut Deterioration IPSDI rulesP

The proposed peaker power plants whose potential annual emissions are below the applicability thresholds of the federal PSID rules are not subject to PSID because the rules define "major sources" in terms of annual emissions from a proposed new source, not monthly or daily emissions. However, as noted above, the Illinois EPA is requiring applicants for "minor' peaker plants to perform air quality impact modeling as if the plants were subject to PSID. The Illinois EPA also has exercised its discretionary authority and is holding public comment periods for all proposed plants before taking final action on a permit. In addition, the Illinois EPA will continue to review the situation.

Can the Illinois EPA place a moratorium on the issuance of permits to Peaker Power plants?

The Illinois EPA does not have the legal authority to impose a moratorium on the issuance of permits to peaker plants. In fact, the Illinois EPA is required to process the permit application for a new plant within 180 days.

Does the Illinois EPA have some say In the location of these facilitiesP

The Illinois EPA does not have a role in the local siting process. Currently there is no state siting requirement for these types of facilities, in contrast to new pollution control facilities such as landfills or wastewater treatment plants. However, even the siting provisions for pollution control facilities leave the decision to the local government in which a proposed facility is to be built.

Can the Illinois EPA issue a permit for a now power plant prior to the company getting zoning approval from the local municipality?

Yes, the Illinois EPA's decision is totally separate from local zoning decisions. Illinois EPA:s approval of a permit does not mean that the proposed power plant should be granted local zoning approval, and conversely local zoning approval does not mean that a plant will be issued a permit by the Illinois EPA. The Illinois EPA:s decisions are based upon the air (and, in certain instances, water) pollution control regulations. Local zoning is based upon other factors including impacts on land use, property value and the local economy.

If a company gets a permit from the Illinois EPA, can the company build even without local approval?

No, the company must build on a location that is appropriately zoned for a power plant. In some cases, the location is already zoned for a power plant; in other cases, the company must obtain a special use approval to build a power plant. In either case, the Illinois EPA's permit does not have any bearing on the local zoning decisions.

If a proposed plant has a permit from the Illinois EPA, does that mean that the facillty Is "ok" and the local municipality most give the company approval to build?

Absolutely not. The role of the municipality is different from the Illinois EPXs role. The local municipality must decide whether a proposed facility is appropriately planned and sited, given its role in local land use management.

An issued permit is stating, in effect, that the company's application shows compliance with the state and federal Air Pollution Control regulations. It is not stating that the facility will comply with other requirements or standards, including local zoning.

Even though the Illinois EPA is not involved in zoning, doesn't the Illinois EPA take Into account proximity to residential areas when issuing a Permit?

As a practical matter, environmental permitting rules assume that all facilities are being built in residential areas even if an area is currently agricultural or industrial in character. As a result, the Illinois EPA's review of the permit is independent of local land use.

How can we he sure that these plants will run all year? Although the **Illinois EPA permits do not limit the plants to** running only during the summer, they do have limitations on how many hours the plant may be run during the year or how much fuel they can burn. The Illinois EPA monitors facilities' compliance with their permit conditions and if violations are found undertakes enforcement actions..

These plants would run when ozone air quality is the worst. How can the Illinois EPA allow new Peaker plants to locate in the Chicago ozone nonattainment area where air quality is already "bad" during the summer? Illinois has made substantial progress in improving ozone air quality in the greater Chicago area, reducing both the extent and magnitude of exceedances of the ozone air quality standard. These new peaker power plants should not interfere with continuing reductions in ambient ozone levels and attainment of the ozone air quality standard. While these plants do emit nitrogen oxide (NOx) which is a precursor to formation of ozone, reductions in NOx emissions are occurring from existing sources such that a substantial decrease in overall ambient concentrations of NOx is occurring in the area. Moreover, the new plants must meet stricter emissions requirements than older plants. In this regard, it should be noted that because ozone is formed by chemical reaction in the atmosphere, the emissions from the new plants will participate in ozone formation many miles downwind rather than at the point at which they are emitted. However, the downwind impacts are being addressed through a national strategy that will include all power plants. In any case, NOx emissions from the new plants would be contributing only a very small part of the overall loading of ozone precursors.

Does the permit Issued to a Peaker power plant regulate noise levels? While the state's noise regulations establish property-line limitations for noise levels, they do not require sources to obtain permits. Nevertheless, we advise facilities such as peaker power plants to utilize noise abatement technology. While the Illinois EPA does not directly enforce the noise regulations, local authorities are empowered to do so, and the Illinois EPA provides technical assistance as necessary. The contact person for noise at Illinois EPA is Greg Zak, who can be reached at 217/782-3397.

What pollutants does a Peaker power plant emit?

The pollutants emitted by peaker plants are the pollutants associated with burning of natural gas for any purpose. The greatest emissions from peaker plants are nitrogen oxides (NOx). Other pollutants emitted include carbon monoxide and, in much smaller amounts, particulate matter, volatile organic material, and sulfur dioxide. These pollutants at proposed levels have no meaningful impact on air quality. NOx emissions from new peaker power plants are minimized by the use of low-NOx burners or water injection into the burners. The low rate of NOx emissions, combined with excellent dispersion, means that the plants would generally have no measurable effect on local NOx air quality.

Will these plans burn any fuels other than Natural gas? Some of the peaker **power plants are** being **developed with the** ability to burn distillate fuel oil. This will allow these particular plants to operate when natural gas is not available. This could be especially useful in the winter time, when natural gas supplies are being used for heating, if a peaker must be called into service as a result of an unexpected outage of an existing power plant.

Who can I contact for more information?

For more information on emissions or permitting status of peaker power plants in Illinois, contact:

Brad Frost
Illinois Environmental Protection Agency
1021 North Grand Avenue East
P.O. Box 19506
Springfield, IL 62794-9506
217/782-7027
217/782-9143 - TDD phone number
1-888/372-1996 (please leave a message)

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