Illinois Environmental Protection Agency
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Project Summary
For a Construction Permit Application from the
Prairie State Generating Company, LLC
for the
Prairie State Generating Station
Washington County, Illinois

Site Identification No.: 189808AAB
Application No.: 01100065
Date Received: October 19, 2001

Schedule:

Public Comment Period Begins: February 6, 2004
Public Hearing: March 22, 2004
Public Comment Period Closes: April 21, 2004

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I. INTRODUCTION

Prairie State Generating Company, LLC (Prairie State) is proposing to construct the Prairie State Generating Station, a 1,500-megawatt power plant in Washington County approximately 5 miles east north east of Marissa.

The plant would have two coal-fired steam electric generating units with a nominal generating capacity of 750 net megawatts each. Prairie State would be a mine-mouth plant and would include a new underground coal mine (Prairie State Mine). The overall site would consist of approximately 600 acres.

The Illinois EPA has prepared a draft of the construction permit that it would propose to issue for the plant. The permit is intended to identify the applicable rules governing emissions from the plant and to set limitations on those emissions. The permit is also intended to establish appropriate compliance procedures for the plant, including requirements for emissions testing, continuous emissions monitoring, record keeping, and reporting. The Illinois EPA has also prepared a draft Acid Rain Permit and a draft Budget Permit for the proposed plant, to address requirements under the federal Acid Rain program and state's NO_x Trading program.

II. PROJECT DESCRIPTION

The proposed plant would have two coal-fired boilers to produce steam, which would be used to generate electricity. The boilers have a nominal rated heat input capacity of approximately 7,450 million Btu/hr each. The principal fuel for the boilers will be Illinois coal (Herrin No. 6). The boilers also will have natural gas capability for startup and shutdown. The plant would be developed to operate as a base load plant, running for months at a stretch, ideally at or near capacity.

The boilers would be of pulverized coal design. In a pulverized coal boiler, the coal is ground (pulverized) to a fine powder immediately before being burned and is blown with primary combustion air into the boiler through a series of nozzles. Secondary air is blown into the boilers through other nozzles to complete combustion. The boilers would be a modern design, with features like dual reheat, to enhance the plant's energy efficiency.

The boilers would be equipped with a multi-stage system to minimize and control emissions. The boilers would be equipped with low NO_x burners and use good combustion practices to reduce emissions of nitrogen oxides (NO_x), carbon monoxide (CO) and volatile organic material (VOM). The add-on control train for each boiler would include selective catalytic reduction (SCR) for control of NOx, an electrostatic precipitator (ESP) for control of particulate matter (PM), wet flue gas desulfurization (WFGD), i.e., a scrubber, for control of sulfur dioxide (SO_2), and a wet electrostatic precipitator (WESP) for control of sulfuric acid mist and condensable particulate matter. The exhaust from the boilers would then be vented through individual flues, one for each boiler, out a single 700-foot high stack.

Other emission units to be constructed at the proposed plant would include: storage, processing and handling equipment for coal, limestone, ash and other materials; two cooling towers; an auxiliary boiler; various roads and parking areas; and various diesel engines.

The water supply for the project will come from the Kaskaskia River. Most of the water consumed for the plant is for cooling.

III. PROJECT EMISSIONS

The potential emissions of the proposed boilers are listed below. Potential emissions are calculated based on continuous operation at the maximum load. Actual emissions will be less to the extent that the plant would not operate at its maximum capacity.

Pollutant	Potential Emission (Tons Per Year)
Particulate Matter (PM)[a]	980
Sulfur Dioxide (SO_2)	11,866
Nitrogen Oxides (NO_x)	5,216
Carbon Monoxide (CO)	7,824
Volatile Organic Material (VOM)	260
Fluorides[b]	17.5
Sulfuric Acid Mist	325
Beryllium	0.0074
Mercury	0.14
Hydrogen Chloride	214
Lead[c]	0.060

Notes: a. Measured as filterable particulate matter, b. Measured as hydrogen fluoride, c. Measured as elemental lead.

For many pollutants, including PM, VOM, fluorides and lead, the potential emissions as listed above are lower than those originally proposed by Prairie State in its initial application. This is a consequence of Prairie State’s ongoing discussions with the Illinois EPA and with potential equipment suppliers. These discussions with equipment vendors and further review of performance also resulted in higher levels of potential emissions of CO and hydrogen chloride.

As addressed by the draft permit, the plant would also have the potential to emit much smaller amounts of emissions from other operations at the plant including the auxiliary boiler, and the storage, processing and handling of coal, ash, limestone and other materials.

IV. APPLICABLE EMISSION STANDARDS

All emission units in Illinois must comply with Illinois Pollution Control Board emission standards. The Board's emission standards represent the basic requirements for sources in Illinois. The various emission units in the proposed plant should readily comply with applicable Board standards.

The coal boilers are also subject to the federal New Source Performance Standards (NSPS), 40 CFR 60 Subpart Da, for electric utility steam generating units. The NSPS sets emission limits for nitrogen oxides, sulfur dioxide and particulate matter emissions from the boilers. Requirements for testing, continuous emissions monitoring, record keeping, and reporting are also specified. Certain other new units are also subject to other NSPS. The Illinois EPA is administering NSPS in Illinois on behalf of the United States EPA under a delegation agreement.

V. OTHER APPLICABLE REGULATIONS

A. Prevention of Significant Deterioration (PSD)

The proposed plant is a major new source subject to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. Under PSD, plant is major for emissions of nitrogen oxides, sulfur dioxide, particulate matter, carbon monoxide, volatile organic materials and sulfuric acid mist with potential annual emissions of more than 100 tons for each of these pollutants for which the proposed location is an attainment area. The plant is also significant for fluorides because potential emissions exceed the PSD significant emission thresholds for these pollutants.

B. Maximum Achievable Control Technology (MACT)

The proposed plant is a major source for emissions of hazardous air pollutants (HAP). The potential HAP emissions from the plant will be greater than 10 tons of certain individual HAP i.e. hydrogen fluoride and hydrogen chloride, and more than 25 tons in aggregate for all HAP. Therefore, the plant is subject to case-by-case review under Section 112(g) of the Clean Air Act for use of Maximum Achievable Control Technology (MACT) to control emissions of HAP, including mercury and other metals, hydrogen chloride and hydrogen fluoride, and various organic HAPs.

C. Acid Rain Program

The proposed plant is an affected source and the two coal-fired boilers are affected units for Acid Deposition: Title IV of the Clean Air Act, and regulations promulgated thereunder. These provisions establish requirements for affected sources related to control of emissions of pollutants that contribute to acid rain.

Under the Acid rain program, Prairie State would have to hold SO2 allowances for the actual SO_2 emissions from the plant. Effectively, this requires reductions in SO_2 emissions from existing coal-fired power plants elsewhere in the United States. This is because the number of SO_2 allowances issued by USEPA to coal-fired power plants annually is fixed, to meet the SO_2 emission target set by the federal Clean Air Act as related to acid rain. Another requirements of the Acid Rain program is to operate pursuant to an Acid Rain permit. The Illinois EPA is proposing to issue the initial Acid Rain permit for the proposed plant in conjunction with issuance of the construction permit for the plant.

D. NO_x Trading Program

The two coal-fired boilers would qualify as Electrical Generating Units (EGU) for purposes of 35 IAC Part 217, Subpart W, NO_x Trading Program for Electrical Generating Units. Accordingly, Prairie State would have to hold NO_x allowances for the actual NO_x emissions of the boilers during each seasonal control period. Effectively this requires reductions in NOx emissions at other existing power plants so that the total seasonal NO_x emissions remain within the budget established by USEPA for power plants in the Midwestern and Eastern United States. Similar to the Acid Rain program, another requirement of the NO_x Trading Program is to operate pursuant to a Budget permit. The Illinois EPA is proposing to issue the initial Budget permit for the coal boilers in conjunction with issuance of the construction permit for the plant.

E. Clean Air Act Permit Program (CAAPP)

This plant would be considered a major source under Illinois' Clean Air Act Permit Program (CAAPP) pursuant to Title V of the Clean Air Act. This is because the plant would be a major source for purposes of the CAAPP because it is a major source for purposes of the above regulatory programs. Prairie State would have to apply for its CAAPP permit within 12 months after initial startup of the plant.

VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Under the PSD rules, Prairie State must demonstrate that Best Available Control Technology (BACT) will be used to control emissions of pollutants subject to PSD (i.e. NO_x, SO_2, CO, PM/PM_{10}, VOM, sulfuric acid mist and fluorides) from the proposed plant. Prairie State has provided a detailed BACT demonstration in its application.

The federal Clean Air Act defines BACT as:

> An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under

> this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.
>
> Clean Air Act, Section 169(3)

BACT is generally set by a "Top Down Process." In this process, the most effective control option that is available and technically feasible is assumed to constitute BACT for a particular project, unless the energy, environmental and economic impacts associated with that control option are found to be excessive. This approach is generally followed by the Illinois EPA for BACT determinations. In addition to the BACT demonstration provided by an applicant in its permit application, a key resource for BACT determinations is USEPA's *RACT/BACT/LAER Clearinghouse* (USEPA Clearinghouse), a national compendium of control technology determinations maintained by USEPA. Other documents that are consulted include general information in the technical literature and information on other similar or related projects that are proposed or have been recently permitted. A summary of the proposed BACT Determination is provided in Attachment 1.

A. BACT Discussion for the Coal-Fired Boilers:

Nitrogen Oxide (NO_x)

Review of the USEPA Clearinghouse indicates that selective catalytic reduction in combination with low-NOx burners, as proposed by Prairie State, are the NO_x control measures used on new pulverized coal boilers. Other add-on control devices have not been used.

Based on available data, the following technologies were reviewed as possible control options for NO_x, in order of highest to lowest effectiveness, in order from most effective to least effective: 1) Selective catalytic reduction (SCR), 2) Selective non-catalytic reduction, 3) Flue Gas Recirculation, and 4) Combustion controls. In addition, Integrated Gasification Coal Combustion (IGCC) was evaluated as an alternative production process for generating electricity from coal.

Selective catalytic reduction (SCR) uses a chemical reaction to remove NO_x from the exhaust gas. The reaction between gaseous NO_x and a reagent, i.e. ammonia (NH_3), as it passes through a porous ceramic bed or screen impregnated with catalyst, reduces NO_x back to N_2. This reaction, which takes place at a temperature of about 750°F, is considered very effective in controlling NO_x. The temperature of exhaust gas from the boilers will be well above this, making it suitable for SCR without reheating the gas. In a pulverized coal boiler, the level of particulates in the exhaust before the electrostatic precipitator is not too high that it prevent the catalyst from working when SCR is installed before the electrostatic precipitator. SCR is a demonstrated technology for control of NO_x emissions from pulverized coal boilers. In addition, new pulverized coal boilers, for which SCR is feasible, achieve similar levels of NO_x emissions as circulating fluidized bed boilers equipped with selective non-catalytic reduction (SNCR) systems.

Selective non-catalytic reduction (SNCR) also involves a reaction with ammonia but without the use of a catalyst. The effectiveness of SNCR is also dependent on temperature and is more sensitive for other factor since it is not facilitated by a catalyst. The temperature of the gas in the reaction zone must be in the range of 1600 to 1800 °F to be suitable for effective operation of an SNCR system. Pulverized coal boilers present several design problems that make it difficult to ensure that the ammonia reagent will be injected at the optimum flue gas and that there will be adequate mixing and residence time. Because of these constraints SNCR is generally considered to provide less percentage reduction compared to SCR. In addition, the necessary temperature is not present in the intermediate zone of pulverized coal boilers. Accordingly, SNCR is more appropriately applied to fluidized bed boilers, given the generally lower levels of combustion NO_x compared to pulverized coal boilers.

Flue gas recirculation controls NO_x by recycling a portion of the flue gas back into the primary combustion zone. The recycled flue gas lowers NO_x emissions by two mechanisms: 1) the recycled gas is made up of combustion products, which are inert during combustion, thereby lowering flame temperatures, and 2) the oxygen content in the primary flame zone is lowered. The amount of recirculation is constrained by the need for flame stability. Although flue gas recirculation may be considered as a possible control option, it is not typically installed on coal-fired boilers. Rather it is generally used on natural gas fired boilers, where it is less effective than either SCR or SNCR.

Combustion controls or low-NOx burners also minimize the formation of NOx by managing the combustion process, i.e., the mixing of fuel and air in the boiler, to reduce the amount of NOx that is formed. For new pulverized boilers, like those proposed, use of low-NOX burners is generally appropriate to reduce the amount of NOx that must be controlled by the add-on SCR system.

Integrated Gasification Coal Combustion (IGCC) is a two-stage process for the production of electricity. In IGCC, coal or other fuel is gasified to produce a synthetic gaseous fuel. This gaseous fuel is then fired in combustion turbines to generate electricity. A review of the small number of existing IGCC projects indicates that IGCC achieves NO_x emission rates that are similar to those achieved by new power plants with boilers that directly fire coal. This similarity in performance is generally explainable because although the synthetic fuel produced by IGCC is in a gaseous state, it has low heat content. Efficient combustion of this fuel in a turbine requires temperatures and oxygen levels in the burners that prevent NO_x emissions from being lower than those achieved by modern coal-fired boilers with add-on NO_x controls. In addition, IGCC is still a developing technology. As a result, the handful of existing IGCC plants have received substantial grants from the United States Department of Energy and IGCC technology cannot be considered a commercially viable technology. The higher costs and the uncertainties associated with IGCC would prevent the proposed plant from being developed. At the present time these factors would also likely preclude use of IGCC for other similar power plant projects being developed primarily with private (non-governmental) financing.

Accordingly, the use of low-NOx burners and add-on SCR is considered BACT for emissions of NO_x from the proposed boilers. The proposed BACT limit is 0.08 lb/million Btu, on a 30-day rolling average. The format of the limit is selected to be consistent with the format used by USEPA in the NSPS for power plant boilers, 40 CFR 60, Subpart Da, which would be applicable to the proposed boilers.

Because temperature of exhaust gas in the SCR will not be in the correct range for effective operation during startup of the boilers, this limit would not apply during startup, i.e., until the conditions are such that the SCR can function effectively. As a general matter, for both NOx and other pollutants, periods of startup, shutdown and malfunction would be addressed through a Start, Shutdown and Malfunction Plan developed and maintained by the plant to assure that appropriate practices are followed during such periods. This is consistent with the general approach to such periods taken by USEPA in its regulations for Maximum Achievable Control Technology (MACT) at 40 CFR Part 63.

<u>Sulfur dioxide (SO_2)</u>

Technically feasible SO_2 control alternatives for the proposed coal boilers include wet flue gas desulfurization (WFGD) and dry scrubbing. Coal washing and fuel selection are also feasible techniques to reduce the sulfur content of the coal. In addition, use of IGCC was considered as a process alternative to reduce SO_2 emissions.

Coal washing is a potential method for reducing SO_2 emissions from the boilers as it would reduce the amount of sulfur contained in the coal. Washing would entail further wet processing of the coal stream after the rotary breaker, which separates rock from the mined coal. The washing process for Illinois coal involves processing the coal with water in jigs or tables to separate impurities from the coal, based upon relative density, as coal is less dense than the impurities. This process reduces the sulfur content of the coal fuel as some sulfur is contained in the impurities rather than in the coal itself. The waste streams from this process are liquid slurry made up of water and impurities and coarse material that can be handled in solid form. While washing is effective in removing rock inclusions from coal, including sulfur-bearing pyrites, a significant amount of coal is also lost with the waste. Thus an inherent consequence of coal washing, in addition to wastewater and solid waste, would be the need for Prairie State to mine and process significantly more coal to make up for that lost in the washing process and for the loss of heat content due to water added to the coal fuel.

Prairie State evaluated coal washing as part of its BACT demonstration, estimating the energy, environmental and economic impacts and other costs associated with coal washing. Prairie State concluded that coal washing is not BACT for the proposed plant because these impacts would be excessive. The Illinois EPA concurs with this conclusion. This finding is premised on the plant being a mine-mouth plant, so that coal washing is not otherwise conducted by Prairie State for the purpose of reducing the costs associated with transporting coal from the mine to the plants at which it is used.

In particular, the analysis supplied by Prairie State indicates that to achieve a 20 percent reduction in the sulfur content of the coal, 22 to 25 percent of the input coal is lost with the waste. To make up for that loss, over 500 additional tons of coal would have to be mined for each ton of equivalent SO_2 emissions removed from the coal, or an additional 1.3 million tons of coal each year based on the capacity of the proposed plant. Even if one assumes that washing would not reduce the efficiency of the scrubber, the cost-effectiveness of coal washing is in excess of $10,000 per ton of SO_2. Coal washing becomes economical when the coal is transported over a distance. Then the savings in transportation costs for the washed coal, which contains 15 to 20 percent more heating value per ton, offsets the costs associated with coal washing.

With respect to alternate sources of coal, e.g., low-sulfur western coal from Wyoming or Montana, the proposed plant is being designed and developed to burn high-sulfur Illinois coal, the locally available coal. It would be inconsistent with the scope of the project to use coal from other regions of the country. Rather, the BACT determination addresses the appropriate control technology for SO_2 emissions associated with use of this coal at the proposed plant. Alternative fuels are only relevant as they support or supplement the use of the local coal, e.g., use of natural gas as proposed to be required for startup of the boilers.

Wet Flue Gas Desulfurization (WFGD) or scrubbing uses sprays of a alkaline solution to react with and absorb the SO_2 in the flue gas. Sulfate salts are formed in the chemical reaction and are removed as a solid waste by-product. WFGD systems are used on pulverized coal boilers burning higher sulfur coals, which must have very effective add-on post combustion systems for control of SO_2 emissions. The emission rates and levels of SO_2 control achieved on new pulverized coal boilers with such systems are comparable to the level of control achieved by new CFB boilers.

Spray drying systems spray thick slurry of lime and water to remove SO_2 from the combustion gases. The spray chamber must be designed to provide adequate contact and residence time between the exhaust gas and the slurry for the removal reaction and for the water to evaporate produce a relatively dry powder that is than collected by the particulate matter control device. While these systems have demonstrated the ability to achieve greater than 90 percent SO_2 reduction on a consistent basis, they are not as effective as wet scrubbing.

The relevant issue for BACT is the SO_2 emission limitation that is established. In this regard, the permit is based on achieving approximately 98 percent control of sulfur present in the design coal supply for the boilers. This is a stringent level of SO_2 control, consistent with or higher than the level of sulfur removal required at other new coal-fired power plants.

In IGCC, the raw fuel gas is treated to remove sulfur compounds before the fuel gas is burned in the turbines. Available information does not indicate that existing IGCC plants are achieving substantially lower SO_2 emission rates than would be required of the proposed boilers. An exact comparison of SO_2 emission rates with IGCC is not possible because of differences in the sulfur content of the fuel supply to existing IGCC plants. In addition, the level of removal being achieved depends on the efficiency that the removal system is designed to achieve.

Prairie State is proposing to use WFGD with limestone in as its SO_2 control system. Because Prairie State is proposing to use the most effective control system, an economic evaluation of this control system is not required.

BACT is proposed to be set at 0.182 lb SO2/million Btu. This reflects a nominal 98 percent reduction in SO2 emissions based on the composition of the local coal supply. BACT would be set on a 30-day rolling average, consistent with the format used by USEPA in the NSPS and by many other states in setting BACT for coal-fired utility boilers.

Particulate matter (PM)

For the proposed boilers, the alternative add-on controls for particulate matter emissions are electrostatic precipitators (ESP) and fabric filters (baghouses). Use of IGCC was also considered. Note that for the purposes of this discussion, particulate matter refers to filterable particulate matter. The Illinois EPA would propose to address condensable particulate matter separately, as discussed later.

ESPs remove particles from exhaust gas by means of electrostatic attraction. Particles in the gas stream are negatively charged by discharge electrodes in the ESP. Once the particles charged, they migrate toward the grounded collection plates in the ESP. Particulate continues to accumulate on the collection plate, agglomerating together until it is removed periodically. The particulate is removed from the plates by mechanically shaking or rapping the plates, rapping only a portion of the plates at any time. The particulate (fly ash) falls by gravity into a hopper for disposal.

A baghouse controls particles by passing the dust-laden air through a bank of cloth filter tubes suspended in a housing. Baghouses are generally considered the most effective particulate control device when low-sulfur coal is burned. In part, this is due to the nature of low-sulfur coal and its flue gas, which result in electrical characteristics that are not ideal for electrostatic collection of dust. These constraints are not present with high-sulfur coal, for which ESPs can be designed and operated to be very effective. In addition, Prairie State has identified technical concerns about the use of a baghouse on the boilers due to the characteristic of the emission stream. The high sulfur content of Illinois coal, compared to either western or eastern coal, accompanied by use of SCR, poses concerns about blinding (clogging) of the filter material with ammonium bisulfate. The sulfur content of Illinois coal would also create highly acidic (corrosive) conditions in a baghouse, which would shorten the life expectancy of the filter material in the baghouse and impair the reliability of the baghouse. At the same time, Prairie State has indicated that ESPs would comply with a limitation that is identical to that being set for other new coal-fired boilers equipped with baghouses.

In these circumstances, i.e., identical limitation, uncertainty about reliability of baghouses, the presence of both wet flue gas desulfurization and wet electrostatic precipitation following the ESP, and cold-side ESP, BACT for particulate matter is proposed as use of a high-efficiency ESP. The proposed BACT limit is 0.015 lb/million Btu. This is the limit that has been set for filterable emissions for many new coal-fired boilers using baghouses and requires very effective control of particulate matter. It is actually lower than the limits that have been set for some new coal-fired boilers equipped with baghouses, e.g., LS Power Plum Point and Kansas City Power and Light, Unit 4, are both limited to 0.018 lb/million Btu.

Sulfuric acid mist

In a coal-fired boiler, a small amount of the sulfur in the coal is converted into sulfuric acid mist. This reaction is similar to the reaction in the atmosphere of much of the SO_2 emitted from the boiler, as the SO_2 gradually reacts to form sulfates. The formation of sulfuric acid mist in a coal-fired boiler is increased by the presence of an SCR system, as the catalyst also facilitates the reaction of SO_2 to SO_3, which then reacts with water to form H_2SO_4, sulfuric acid. While sulfuric acid mist is recognized as a separate pollutant, it also constitutes a major component in the condensable particulate matter emissions from a coal-fired boiler.

While wet flue gas desulfurization (WFGD) provides some control of sulfuric acid mist, by absorbing the mist in the alkaline scrubbant, the established control technique for sulfuric acid mist for chemical processes that generate sulfuric acid mist is wet electrostatic precipitation (WESP). WESPs operate much the same way as dry ESPs, i.e., electrical charging, collecting, and then cleaning. The difference between the design of the two systems lies in the cleaning step and tolerance for moisture. WESP cleaning is performed by washing the collection surface with water spray nozzles and liquid removal systems employing water washes, rather than mechanical means such as rapping of the collection plates.

WESPs are the most effective control device for sulfuric acid droplets, as demonstrated by installation of WESPs at acid production plants and other industrial sources that have highly acidic exhaust streams. Relatively high levels of SO_3 in the exhaust gas greatly improve the collection efficiency of the WESP by reducing the electrical resistance of the acid droplets. In addition to controlling sulfuric acid mist, WESPs also provide additional control of filterable particulate and emissions of other acid gases, which are present in the exhaust in very small droplets of water

When used in conjunction with WFGD, WESPs are also effective in reducing emissions of other fine particulate. Prairie State has selected WESP as BACT for controlling sulfuric acid mist. This also provides control for condensable particulate matter.

The emissions limit that is proposed as BACT for sulfuric acid mist is 0.005 lb/million Btu. This is below the emission limits set or proposed for sulfuric acid mist emissions for other recent coal-fired power plant projects. Accordingly, this limit requires very effective control of acid mist emissions from the boilers.

This limit on emissions of sulfuric acid mist emissions would also serves as a surrogate for control of condensable particulate matter from the boilers, which for purposes of BACT is being addressed as a separate pollutant from filterable particulate matter. This approach is proposed by the Illinois EPA because of the limited data that is available on the rates of condensable emissions from pulverized coal boilers, especially new boilers burning Illinois coal which are equipped with high-efficiency SCRs, rather than existing boilers to which an SCR has been retrofit. While some permitting authorities in other states have established BACT emission limits that address total particulate matter (filterable and condensable), the Illinois EPA does not believe that there is an adequate basis upon which to establish such a limit for the proposed boilers. The limits for combined particulate matter set or proposed in these other states, which range from 0.018 to 0.055 lb/million Btu, do not provide a reliable basis to set such a limit. In addition, the USEPA method for testing emissions of condensable particulate matter, Method 202, accommodates variations in the test procedures to reflect variations in state practices with respect to the scope of condensable particulate matter.

Carbon monoxide (CO)

Carbon monoxide (CO) is a product of incomplete combustion. The control methods are 1) Excess air and 2) Design of the combustion process and good combustion practices to minimize the formation of CO. In addition, use of IGCC was considered as a process alternative for the plant to reduce CO emissions.

A large amount of excess air in a boiler could theoretically reduce CO emissions by up to 75% by raising the amount of oxygen available complete oxidation of CO into CO_2. Excess air, however, is not listed as a control method for coal boilers in the RBLC database. Use of this technique would have the adverse environmental impact of increasing emissions of other pollutants, particularly thermal NO_x, which is supported by excess air, as well as having a negative impact on the energy efficiency of a boiler.

From a practical standpoint, this method is not feasible for a coal boiler because the additional volume of air would lower the temperature in the boiler. This would (1) reduce boiler thermal efficiency, and (2) greatly increase the fuel requirement. The increased fuel requirement alone would increase emissions of PM, SO_2, and NO_x from the boiler. Additionally, the increase in the available oxygen in the excess air would counteract the impact in the combustion zone causing an increase in NO_x emissions from the boiler. Creating higher PM/PM_{10}, SO_2, and NO_x, emissions to reduce

CO emissions is an unacceptable environmental consequence of employing excess air. For these reasons, excess air is not considered BACT for CO emissions.

A properly designed and operated boiler effectively functions as a thermal oxidizer. CO formation is minimized when the boiler temperature and excess oxygen availability in the combustion zone of the boiler are adequate for complete combustion. CO emission rates are identified as a potential factor that affects NO, emissions on an inverse relationship (i.e., lower CO tends to be accompanied by higher NO_x). For the proposed plant a more stringent limit of CO emissions, achieved with additive through excess air would be counterproductive given the need to reduce NO_x emissions.

Proper boiler design and operation will provide a low CO emission rate. Prairie State proposes to meet a CO emission limit of 0.12 lb/million Btu, which is chosen as BACT for CO emissions from the proposed boilers. Prairie State's proposed choice is supported by recent entries in the USEPA Clearinghouse for coal- fired boilers and the limitations set for recently permitted coal-fired utility boilers.

Volatile Organic Materials (VOM)

Volatile organic material (VOM) is formed from incomplete combustion of the coal. At the same time, combustion is the most efficient means of destroying VOMs. In combustion VOM is burned and are converted into CO_2 and water vapor. Factors affecting completeness of combustion are temperature, turbulence or mixing of the VOM and air (oxygen) and the residence time in the combustion zone. The inherent operation of Utility Boilers provides all of the factors facilitating complete combustion, including extended residence time, consistent high temperatures in the combustion zone and effective mixing of air and fuel.

The USEPA Clearinghouse does not identify any add-on controls determined to be BACT for emissions of VOMs from coal-fired Boilers. Historically, utility boilers have been viewed as giant thermal oxidizers of VOMs. Therefore, BACT for VOMs is proposed to be proper boiler design and operation with an emission limit of 0.004 1b/mmBtu. This emission limit is based on design and good operating practices.

Lead

Lead is emitted as a constituent of the particulate matter emitted from the boilers. Therefore, use of an ESP as BACT for particulate matter also represents use of BACT for lead.

C. BACT Discussion for Other Emission Units

In its application, Prairie State also addresses BACT for other emission units at the proposed plant. Appropriate control measures are proposed. For the auxiliary boiler, natural gas is identified as the sole fuel and low-NO_x burners are proposed. High-efficiency drift eliminators are proposed for the cooling towers. Particulate emission control from coal, ash, and limestone handling will be effectively controlled in a variety of ways. These include use of baghouses and implementation of other control measures to effectively control process particulate matter and fugitive dust emissions from handling of fine material with the potential to generate dust. Fabric filter control is proposed for storage silos and to control emissions from the coal breaker. Fugitive dust control will encompass a variety of suppression or elimination techniques including partial or total enclosure, paving (roadways), and compaction and/or chemical or wet suppression (storage piles).

VII. MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT)

The proposed plant is a major source of hazardous air pollutants (HAPS) with potential annual emissions of hydrogen chloride and hydrogen fluoride greater than 10 tons. The coal-fired boilers are the principle source of HAP emissions at the plant, due to the presence of chlorine, fluorine, mercury, lead and other heavy metals in coal.

A case-by-case MACT determination is required for the plant under Section 112(g of the federal Clean Air Act because USEPA has not yet adopted MACT standards for boilers at electric power plants. While USEPA has formally proposed such standards on January 30, 2004, the standards may not be adopted in the form proposed by USEPA. As a general matter, adopted rules may differ from proposed rules as the proposed rules are subject to public comment and further review by the regulatory authority. Moreover, in its notice of proposed rulemaking, USEPA solicited comments on whether it should proceed to adopt emission limits for MACT standards or should proceed to regulate HAPS, i.e., mercury emissions, with another approach that would allow trading of mercury allowances.

If USEPA proceeds to adopt MACT standards for power plant boilers, the proposed plant would be subject to the adopted standards. Accordingly, the case-by-case determination of MACT being made in the draft permit for the proposed plant is only intended to address the contingency that USEPA does not adopt such standards and the plant is required to comply with MACT.

<u>Mercury</u>

The mercury emission rate for the coal-fired boilers was determined based upon the case-by-case analysis presented in the application and review of information on mercury emissions prepared by USEPA and others. The mercury emission rate used to calculate potential emissions is 0.000020 lb/megawatt-hr consistent with recently permitted limits for power plants. Given the nature of the data on mercury emissions from coal-fired boilers, the permit establishes two alternatives to compliance with the emission rate. These alternatives are:

1. Achievement of a removal efficiency of 95 percent achieved without injection of activated carbon or other similar material specifically used to control emissions of mercury.

2. Injection of powdered activated carbon or other similar material for the maximum practicable degree of mercury removal.

Hydrogen Chloride

The hydrogen chloride emission rate was determined based upon the case-by-case analysis presented in the application and review of other information. The emission rate used to calculate potential emissions is 0.0032 lb/million Btu. Given the nature of the data on the hydrogen chloride emissions from coal-fired boilers and the use of add-on WFGD and WESP by the boilers, a single alternative is provided, achievement of a removal efficiency of 98 percent.

Other

The Illinois EPA has determined that the MACT for fluorides will be achieved by the specific control measures for particulate matter, sulfur dioxide, and hydrogen chloride. The fluorides emission rate used to calculate potential emissions is 0.00026 lb/million Btu.

For other emission units, emissions of HAP will be appropriately controlled by the measures required as BACT and HAPs will be present in the particulate matter and volatile organic material emissions from the units.

VIII. AIR QUALITY ANALYSIS

A. Introduction

The previous discussion addressed emissions and emission standards. Emissions are the quantity of pollutants emitted by a source, as they are released to the atmosphere from a stack. Standards are set limiting the amount of these emissions primarily as a means to address the quality of air. The quality of air as we breathe it or as plants and animals experience it is known as ambient air quality. Ambient air quality considers the emissions from a particular source after they have dispersed following release from a stack, in combination with pollutant emitted from other nearby sources and background pollutant levels.

The concern for pollutants in ambient air is typically expressed in terms of the concentration of the pollutant in the air. One form of this expression is parts per million. A more common scientific form is microgram per cubic meter, millionth of a gram in a cube of air one meter on a side.

The United States EPA has established standards, which set limits on the level of pollution in the ambient air. These ambient air quality standards are based on a broad collection of scientific data to define levels of ambient air quality where adverse human health impacts and welfare impacts may occur. As part of the process of adopting air quality standards, the United States EPA compiles the various scientific information on impacts into a “criteria” document. Hence the pollutants for which legal air quality standards exist are known as criteria pollutants. Based upon the nature and effects of a pollutant, appropriate numerical limitation(s) and associated averaging times are set to protect against adverse impacts. For some pollutants several standards are set, for others only a single standard has been established.

Areas can be designated as attainment or nonattainment for criteria pollutants, based on the existing air quality. Areas in which the air quality standard is met for a pollutant are known as attainment. If the air quality standard is exceeded, the area is known as nonattainment. Given the geographic extent of areas designated as nonattainment and the USEPA’s process for redesignating an area to attainment, the air quality in some or all of an area designated as nonattainment may actually be in compliance with the relevant air quality standard.

In attainment areas one wishes to generally preserve the existing clean air resource and prevent increases in emissions, which would result in nonattainment. In a nonattainment area efforts must be taken to reduce emissions to come into attainment. An area can be attainment for one pollutant and nonattainment for another.

Compliance with air quality standards is determined by two techniques, monitoring and modeling. In monitoring one actually samples the levels of pollutants in the air on a routine basis. This is particularly valuable as monitoring provides data on actual air quality, considering actual weather and source operation. The Illinois EPA operates a network of ambient monitoring stations across the state.

Monitoring is limited because one cannot operate monitors at all locations. One also cannot monitor to predict the effect of a future source, which has not yet been built, or to evaluate the effect of possible regulatory programs to reduce emissions. Modeling is used for these purposes: Modeling uses mathematical equations to predict ambient concentrations based on various factors, including the height of a stack, the velocity and temperature of exhaust gases, and weather data (speed, direction and atmospheric mixing).

Modeling is performed by computer, allowing detailed estimates to be made of air quality impacts over a range of weather data. Modeling techniques are well developed for essentially stable pollutants like particulate matter, NO_x, and CO, and can readily address the impact of individual sources. Modeling techniques for reactive pollutants, e.g., ozone, are more complex and have generally been developed for analysis of entire urban areas. They are not applicable to a single source with small amounts of emissions.

Air quality analysis is the process of predicting ambient concentrations in an area or as a result of a project and comparing the concentration to the air quality standard or other reference level. Air quality analysis uses a combination of monitoring data and modeling as appropriate.

B. Air Quality Analysis for NO_2, SO_2, PM10 and CO (NAAQS and Class II Increment)

An ambient air quality analysis was conducted by a consulting firm, Kentuckiana Engineering, on behalf of Prairie State to assess the impacts of the proposed plant on ambient air quality. Under the PSD rules, this analysis must demonstrate that the proposed project will not cause or contribute to a violation of any applicable air quality standard or PSD increment.

The starting point for determining the extent of the modeling necessary for this facility was evaluating whether the proposed plant would have a "significant impact". The PSD rules identify Significant Impact Levels, which represent thresholds triggering a need for more detailed modeling. These thresholds are specified for all criteria pollutants, except ozone and lead. The significant impact levels do not correlate with any health or welfare thresholds for humans, nor do they correspond to a threshold for effects on flora or fauna. For pollutants for which impacts were above the significant impact level, modeling was done incorporating proposed new emissions units at proposed plant and significant stationary sources in surrounding area.

The Illinois EPA performed selected audit modeling runs to verify the applicant's results for the preliminary impact analysis, full impact analysis, and hazardous air pollutants (HAPs) modeling. The accompanying tables (Tables 1 - 4) summarize the Prairie State's results and the Illinois EPA's audit results.

TABLE 1

PRELIMINARY IMPACT ANALYSIS
(SIGNIFICANT IMPACT ASSESSMENT)

Pollutant	Averaging Period	Significant Impact Increment (ug/m^3)	National Ambient Air Quality Standard (NAAQS) (ug/m^3)	Maximum Modeled Concentration[a] Per Prairie State (ug/m3)	Maximum Modeled Concentration[a] Per Illinois EPA Audit[b] (ug/m3)
NO_x	Annual	1	100	0.82	0.99[e]
SO_2	3-Hour	25	1,300	121.32	123.70
	24-Hour	5	365	21.00	20.98
	Annual	1	80	0.70	0.67
PM_{10}	24-Hour	5	150	31.22	31.53[c]
	Annual	1	50	4.86	4.97[d]
CO	1-Hour	2,000	40,000	199.96[f]	259.24[f]
	8-Hour	500	10,000	42.65[f]	71.34[f]

<u>Notes</u>:

a. High 1st high value based upon individual evaluation of each year of a 5-year meteorological dataset.

b. The Illinois EPA's audit runs incorporated building parameter data for all sources subject to downwash. Emission factors for hourly emission rate variation were eliminated. For short-term averaging periods, fire pump emissions were based upon two consecutive hours of operation within any day.

c. Maximum modeled concentration obtained for a scenario in which the coal boiler emissions are zeroed (i.e., early start-up)

d. Maximum modeled concentration obtained for a scenario in which the auxiliary boiler is not operating.

e. The Illinois EPA's adjustment of model input for the emergency engines, providing for continuous operation, initially resulted in an impact greater than the significant impact level, i.e., 1.37 ug/m^3. Operational restrictions on diesel engines reduced the impact to below the significant impact levels, so that plant's modeled impact is below the significant impact threshold (1 ug/m^3).

f. Updated to reflect a CO emission rate of 0.012 lb/million Btu from the coal boilers.

The preliminary impact analysis showed maximum concentrations for PM10 and SO_2 (3-hour and 24-hour average, only) that are greater than applicable significant impact levels. This triggered further analysis with modeling of both the proposed plant and existing sources in the area. Consideration was also given to the background levels of air quality, as determined at ambient monitoring stations operated by the Illinois EPA. This full impact analysis yielded concentrations (see following Tables 2 and 3) in excess of the PSD increments and NAAQS. However, the proposed plant did not contribute significantly to these modeled exceedances, i.e., its contribution was below the significant impact levels. These exceedances are due to other modeled sources, which are receiving follow-up evaluation by the Illinois EPA. Differences in the Illinois EPA's and consultant's output are linked to the application of building-induced aerodynamic downwash for selected versus all potential units, the use/non-use of hourly emission rate variation for the emergency engines, implementing (or not) emission rate adjustments for intermittently operated units based upon operational scenario (auxiliary boiler on-line or not) and averaging time, and concentration reporting interpretation (e.g. highest 2nd high concentration versus highest 6th high concentration).

TABLE 2

PSD CLASS II INCREMENT CONSUMPTION MODELING RESULTS

Pollutant	Averaging Period	Class II PSD Increments (ug/m^3)	Maximum Concentration Per Prairie State (ug/m^3)	Maximum Concentration Per Illinois EPA Audit (ug/m^3)
SO_2	3-Hour	512	275.52[a, b, e]	278.99[a, e]
	24-Hour	91	42.30[a, b, e]	34.81[a, e]
PM_{10}	24-Hour	30	45.22[a, c]	45.22[a]
	Annual	17	4.99[d]	5.04[d]

Notes

a. High 2nd high value based upon individual evaluation of each year of a five year meteorological dataset.

b. Prairie State's downwashed units and hourly emissions allocations were slightly different from those chosen by the Illinois EPA.

c. The proposed plant, in aggregate, had zero contribution to this maximum reported highest, 2nd high concentration. For all modeled impacts exceeding the PM_{10} Class II PSD increment, units at the proposed plant, individually and in aggregate did not contribute above the significant impact level.

d. High 1st high value based upon individual evaluation of each year of a five year meteorological dataset.

e. Results based upon an SO_2 emission rate of 0.51 lb/million Btu for the proposed coal boilers.

Results of the full impact assessment modeling (in Tables 2 and 3) have shown violations of the 24-hour PM_{10} PSD Class II increment, the 3-hour SO_2 NAAQS, and both 24-hour and annual PM_{10} NAAQS. A culpability analysis of source contributions at those receptors and times at which the modeled violations occur reveals that the contribution of the proposed plant (in aggregate) would be below the significant impact level. The modeled SO_2 and PM_{10} exceedances are due to other sources. The Illinois EPA will investigate the modeled exceedances to determine whether they are due to inaccuracies in the emission or stack data in the inventory for certain existing sources, as is suspected.

TABLE 3

NAAQS MODELING RESULTS

Pollutant	Averaging Period	NAAQS (ug/m^3)	Background Concentration (ug/m^3)	Prairie State's Maximum Modeled Concentration (ug/m^3)	Total Concentration (ug/m^3)	Background Concentration (ug/m^3)	Maximum Modeled Concentration per Illinois EPA (ug/m^3)	Total Concentration (ug/m^3)
SO_2	3-Hour	1300	143.97[a]	1854.93[a, c, l]	1998.90	143.97[a]	1926.22[a, c, l]	2070.19
	24-Hour	365	41.88[a]	459.85[b, l]	501.73	41.88[a]	459.69[b, l]	501.57
PM_{10}	24-Hour	150	54[d]	299.62[e, f]	353.62	54[d]	242.50[g, h]	296.50
	Annual	50	28[i]	30.55[j, k]	58.55	28[i]	30.55[j, k]	58.55

<u>Notes</u>

a. Average highest 2nd high concentration for the combined Houston and Marissa ambient air quality monitors (2000).

b. High 2nd high value based upon individual evaluation of each year of a 5-year meteorological dataset.

c. For all modeled impacts causing or contributing to exceedances of the SO_2 3-hour average NAAQS, the proposed plant did not contribute above the significant impact level.

d. Average highest 2nd high concentration for combined Carbondale and East St. Louis ambient monitors (2000).

e. Prairie State supplied summary output for the high 2nd high concentration as evaluated for each year of five years of meteorological data, not the highest 6th high concentration over the entire meteorological dataset.

f. The proposed plant, in aggregate, did not contribute above the significant impact level to this modeled concentration nor for any other modeled exceedances of the PM_{10} 24-hour average NAAQS.

g. The proposed plant, in aggregate, did not contribute at all to this 6th highest concentration. For all modeled impacts causing or contributing to exceedances of the PM_{10} 24-hour average NAAQS, units at the proposed plant individually and in aggregate did not contribute above the significant impact level.

h. Highest 6th high concentration with five years of meteorological data.

i. Average annual arithmetic mean concentrations for combined Carbondale and East St. Louis ambient monitors (1998-2000).

j. Arithmetic average of high 1st high value of each year of a five year meteorological dataset.

k. The proposed plant, in aggregate, contributed 0.06 ug/m^3 to the maximum reported modeled concentration. For all modeled impacts causing or contributing to exceedances of the PM_{10} annual average NAAQS, the units at the proposed plant individually, and in aggregate, did not contribute above the significant impact level. For modeled impacts not causing or contributing to an exceedance, the maximum total plant contribution was 4.91 ug/m^3.

l. Results based upon an SO_2 emission rate of 0.51 lbs/million Btu for the proposed coal boilers. Prairie State's original air quality analysis was based on the BACT limit for SO_2 emissions from the coal-fired boilers, i.e., 0.182 lb/million Btu. This represented the performance of the wet flue gas desulfurization (WFGD) system on a 30-day average. Prairie State subsequently realized that the daily SO_2 emission rate had not been properly identified and that the daily rate could be significantly higher than the 30-day average rate, given variation in the performance of the WGFD system. Accordingly, it then supplemented its application with a maximum daily emissions rate that reflected the variability in the performance of the WFGD system on a daily basis. It first selected a limit of 0.51 lb/million Btu, which is the basis of the above modeling. It subsequently reduced this limit to 0.42 lb/million Btu, so that the above results overstate impacts.

Incidentally, preliminary concerns have been expressed by the U.S. Fish and Wildlife Service that the daily emission limit sought by Prairie State allows for more variation in the performance of the WFGD than is needed to accommodate routine or typical variation in scrubber performance. To address this concern, the draft permit would provide for the daily SO_2 emission limit to be evaluated based on actual operating experience with the WFGD system and lowered to appropriately address the actual variability in system performance.

C. Analysis of Impacts on Class I Areas

The area closest to the proposed plant that is subject to the Class I PSD Increments is at the Mingo National Wildlife Refuge near Lake Wappapello in southeastern Missouri, approximately 170 kilometers (105 miles) away from the proposed plant. The Class I area at this wildlife refuge, which extends over 21,700 acres, is the approximately 7,700 acre area at the refuge that is designated a wilderness area. Public access to the wilderness area is only allowed by foot or non-motorized boat. Hunting, which is allowed on a seasonal basis elsewhere in the refuge, is prohibited in the wilderness area.

At the request of the Federal Land Manager for the Mingo Refuge, Prairie State submitted modeling to address the impacts of the proposed plant on Class I increment consumption, visibility, and acid deposition at the Mingo Wilderness Area. The Federal Land Manager has the primary responsibility for evaluating a proposed project's Class I impact analysis. However, the Illinois EPA has independently reviewed the documentation provided by Prairie State to gain familiarity with the modeling methodologies and to understand the analytical results.

<u>Increment Consumption</u>

As initially reported (Table 5), the Class I SO_2 increment consumption results (3-hour and 24-hour average impacts) did not show exceedances of the PSD Increments. The modeled PM_{10} and NO_x concentrations and annual SO_2 impacts were all below their respective significant impact levels.

TABLE 4

PSD CLASS I INCREMENT CONSUMPTION MODELING RESULTS

Pollutant	Year	Averaging Period[a]	Significant Impact Levels (ug/m^3)	Class I PSD Increments (ug/m^3)	Maximum Concentration[b] (ug/m^3)
SO_2	1990	3-Hour	1.0	25	10.3
		24-Hour	0.2	5	4.1
	1992	3-Hour	1.0	25	9.7
		24-Hour	0.2	5	3.2
	1996	3-Hour	1.0	25	9.9
		24-Hour	0.2	5	3.6

Notes

a Modeled SO_2 annual average impacts for the proposed plant were less than the significant impact level (0.1 ug/m^3); consequently, no cumulative increment consumption analysis was performed for this averaging time. The applicable significant impact levels for PM_{10} (0.3 ug/m^3 for the 24 hr average; 0.2 ug/m^3 for the annual avg.) and NO_x (0.1 ug/m^3 annual avg.) were also not exceeded, and no cumulative increment consumption analyses were performed for these pollutants.

b High 2nd high value.

Prairie State also performed supplemental modeling for Class I Increment consumption to address a daily SO_2 emission limit based on a daily emission rate higher than 0.182 lbs/million Btu. This modeling still indicates maximum concentrations (highest 2nd high values) below the PSD increments.

Finally, after being informed by the Federal Land Manager of the omission of the recently permitted Plum Point Energy Station in Arkansas from the Class I increment consumption inventory, Prairie State provided additional modeling to address this new plant. Given the spatial relationship of the proposed plant and the Plum Point plant, northeast and southwest respectively of relative to the Mingo Wilderness Area, the interactive effects of these plants would not be expected to change short term averaging period impacts. The additional modeling confirmed that the increment was still protected on annual average basis.

Visibility Impact Analysis

Prairie State conducted an assessment of the impact of the emissions of the proposed plant on visibility at the Mingo

Wilderness. For this purpose, visibility means the presence of material in the atmosphere that obscures or scatters the passage of light and interferes with the human perception of scenery or vistas. Visibility is affected both by natural atmospheric and meteorological conditions and by the presence of anthropogenic emissions in the atmosphere. While good visibility is clearly an esthetic value, poor visibility and degradation of visibility also pose concerns for air quality and the environment if they are attributable to the presence of pollutants in the atmosphere.

Coal-fired power plants, like the proposed plant, are of concern for visibility due to emissions of particulate matter and gaseous SO_2 and NO_x, which react in the atmosphere to form sulfates and nitrates. As with air quality impacts, computer modeling has been developed to predict the impacts of emissions of different pollutants on visibility. However, visibility modeling is more complex than the modeling typically used for PSD air quality analyses as it must address long range transport of pollutants, the reactions and transformation that occur during transport, and the role of the moisture, ammonia and ozone in the atmosphere in these reactions. Prairie State's visibility modeling was performed by EarthTech using the Calpuff Modeling System, a model that is generally approved by USEPA for use in PSD permitting. Personnel at EarthTech were responsible for the initial development of the Calpuff model and are involved in the continued evolution of this modeling system.

Visibility is typically evaluated in terms of the extent to which the passage of light is obscured or extinguished as it passes through the atmosphere. Prairie State's visibility modeling for the emissions of the proposed plant over a period of three years identified one day with reduced visibility corresponding to greater than 10 percent light extinction (12.1 percent) compared to natural conditions. The modeling also identified three days with light extinction between 5 and 10 percent (6.1, 6.4 and 7.5 percent). According to the guidance developed for visibility analysis by the Federal land managers (Federal Land Managers' Air Quality Related Values Workgroup Phase I Report, December 2000 or "FLAG Guidance"), these impacts exceed the threshold (5 percent light extinction) for performing a further "cumulative visibility analysis," which would also address other sources of emissions. It also poses a concern for an adverse impact as the predicted impact on one day is in excess of 10 percent.

Accompanying its visibility analysis, Prairie State also provided written reports by Dr. Ivar Tombach challenging some of the assumptions in the FLAG Guidance as specifically applied to the topography and other circumstances at the Mingo Wilderness Area (Natural Visibility Conditions at the Mingo Wilderness Area (July 6, 2003) and Human Perception of Visibility Impairment at the Mingo National Wildlife Refuge and Wilderness Area, July 6, 2003). For example, Dr. Tombach discusses the sight paths present at the Mingo Wilderness, i.e., the actual distance between a potential observer and vistas at the Mingo Wilderness. This is a relevant consideration in deciding whether the level of light extinction predicted by modeling could actually be perceived by a human observer and affect their appreciation of a vista. Prairie State uses this material to show that the predicted levels of impacts from the proposed plant should not be considered to constitute an adverse impact on visibility at the Mingo Wilderness area and should not act to trigger the requirement for a cumulative assessment of visibility impacts. Accordingly, Prairie State did not provide a "cumulative visibility analysis" as otherwise recommended by the FLAG Guidance.

The Illinois EPA agrees that Dr. Tombach raises issues that may be relevant for evaluation of the predicted impacts on visibility at the Mingo Wilderness. More importantly, however, any cumulative visibility assessment prepared for the proposed plant would also need to include contemporaneous reductions in emissions from coal-fired power plants in southwestern Illinois. Given the magnitude of such reductions, any such analysis would likely show improvements in visibility at the Mingo Wilderness as related to the emissions from sources in Illinois.

In particular, in 2002, Ameren repowered its coal-fired power plant at Grand Tower with natural gas fired turbines. This resulted in an actual annual emission reduction of over 20,000 tons of SO_2 and 800 tons of NO_x. This plant is located approximately 65 miles northeast of the Mingo Wilderness. In 2000, Dynegy switched to low-sulfur western coal at its Baldwin power plant. This has resulted in an actual annual reduction in SO_2 emission of approximately 200,000 tons. This plant is located approximately 100 miles north northeast from the Mingo Wilderness, almost in line with the proposed power plant.

Moreover, it could also be appropriate in a cumulative visibility analysis to consider the role of the existing Acid Rain and NOx Trading Programs, as Prairie State would be required to obtain allowances for the SO_2 and NO_x emissions of the proposed plant. Given the number of coal-fired power plants in the general vicinity of the Mingo Wilderness, some of those allowances and associated emissions reductions would likely come from power plants that currently affect visibility in the Mingo Wilderness. Similarly, USEPA is moving forward with an Interstate Pollution program to further reduce SO_2 and NO_x emissions from coal-fired power plants. It is unclear how those future reductions, which should start to occur at about the time that the proposed plant would begin operation, should be addressed in a cumulative visibility analysis. In this regard, the circumstances of coal-fired power plants are very different than those of other categories of sources, for which national emission reduction programs are not in place or proposed.

In light of these contemporaneous emission reductions, along with the issue posed by Dr. Tombach, the Illinois EPA does not believe that there is sufficient information to find that the proposed plant would have an adverse impact on visibility at the Mingo Wilderness.

Deposition Analysis

Nitrogen deposition results exceed the western U.S. "deposition analysis threshold" for modeled years 1990 and 1996. Sulfur deposition results exceed both eastern and western U.S. deposition analysis thresholds for all three years modeled. A supplementary analysis of these deposition impacts (James R. Kramer, Aquatic Assessment of Mingo Wilderness Area (MWA), August 1, 2003) submitted by Prairie State concludes "there would be a non-detectable change in precipitation chemistry and in the surface water acid-base chemistry with the additional deposition contribution from PSGS". This is generally due to the ample buffering capacity in surface waters.

D. Ozone Air Quality

The Illinois EPA has conducted an assessment of the impact of the proposed plant and other proposed or recently permitted coal-fired power plants on ozone air quality due to their emissions of VOM, NO_x and CO (ozone precursors). The Illinois EPA decided to conduct this assessment because of the magnitude of the potential NO_x emissions of these plants and concern that the plants could interfere with the established plan to achieve and maintain compliance with the 1-hour ozone standard in the St. Louis/Metro East area.

Illinois EPA conducted photochemical modeling with plant emissions as proposed in the application or as set by a permit combined with other inventories for input into the Urban Airshed Model (UAM-V). The modeling was conducted for base year (1996) for attainment planning as well as future year (2004) scenarios, and it evaluated three historical episodes with differing wind patterns that produced high ozone levels. Model output was compared against performance statistics, predicted ozone concentrations and various "tests" from the St. Louis ozone attainment demonstration (June, 2000). An in-depth discussion of the modeling procedure and model output evaluation is provided in the report Assessing the Impact on the St. Louis Ozone Attainment Demonstration from Proposed Electrical Generating Units in Illinois (September 25, 2003). The report concludes that these additional power plants would not adversely impact continued attainment of the 1-hour ozone standard in the St. Louis area.

In the future, the Illinois EPA will address the emissions of the proposed plant as it conducts evaluations and develops Illinois' attainment strategy for the St. Louis/Metro-East area for the new 8-hour ozone standard.

E. Modeling for Hazardous Air Pollutants (HAPs)

Prairie State also submitted hazardous air pollutant (HAP) modeling. HAP modeling results (24-hour average impacts for mercury, beryllium, and fluorides) were evaluated by comparing them against monitoring de minimus levels. This modeling used meteorological data for 1986, 1987, 1989, 1990 and 1991 like the modeling for criteria pollutants.

TABLE 5

HAP MODELING RESULTS AND DE MINIMUS MONITORING LEVELS

Receptor		Fluorides		Mercury		Beryllium	
x-utm (m)	y-utm(m)	Maximum Concentration[a] (ug/m^3)	Monitoring DeMinimus (ug/m^3)	Maximum Concentration[a] (ug/m^3)	Monitoring DeMinimus (ug/m^3)	Maximum Concentration[a] (ug/m^3)	Monitoring DeMinimus (ug/m^3)
267,548.47	4,240,585.50	0.14552	0.25	0.00017	0.25	0.00059	0.001

<u>Notes</u>

a. Highest 2nd high concentration. For all pollutants, meteorological data for 1986 produced the highest 2nd high concentration.

F. Vegetation and Soils Analysis

Prairie State provided an in-depth analysis of the impacts of the proposed plant on vegetation, animals, and soils, and on emissions impacts resulting from residential and commercial growth associated with construction of the proposed plant ("additional impact analysis").

The first several steps in this process focus on the use of modeled air concentrations and published screening values for evaluating exposure to flora from selected criteria pollutants (SO_2, NO_x, CO, ozone and lead) and other pollutants (hydrogen sulfide, fluorides, and beryllium). These screening values or threshold ambient concentrations (which may indicate levels of potential adverse impacts) are provided for "sensitive", "intermediate", and "resistant" species. The applicant has conservatively compared maximum modeled concentrations against "sensitive" species threshold concentrations, and in all instances, modeled impacts are below the "sensitive" value thresholds.

Potential adverse impacts to soil and biota from deposition of hazardous air pollutants (trace elements including hazardous metals) are the focus of the methodology. In this stepwise process, soil (depositional) loadings calculated from annual average air concentrations (modeling results) are combined with published endogenous soil concentration data and compared against threshold impact information. Dispersion modeling results were obtained for short- and long-term averaging periods for arsenic, cadmium, cobalt, selenium, chromium, fluoride, lead, manganese, mercury, and nickel. Annual average concentrations were converted to deposited soil concentrations and plant tissue concentrations and compared against screening levels for soil, plant tissue, and dietary intake (animals). In all cases, the pollutant levels were less than the screening levels.

The proposed plant's emissions are not expected to result in harmful effects to the soils and vegetation in the area. Maximum modeled impacts for NO_x, CO and PM_{10} do not exceed the secondary NAAQS level set forth by USEPA. Maximum modeled 3-hour average SO_2 impacts do not exceed the significant impact level for secondary standard.

Discussions between the Illinois EPA and the Illinois Department of Natural resources, as required under Illinois' Endangered Species Act, are ongoing, to review the above conclusions with respect to species of vegetation that are present in the area that are endangered. These discussions also addressing endangered species of animals present in the area.

G. Construction and Growth Analysis

Prairie State provided a discussion of the emissions impacts resulting from residential and commercial growth associated with construction of the proposed plant ("additional impact analysis"). Anticipated residential, commercial, and industrial growth associated with construction and operation of the proposed plant are expected to be low, as are the emissions resulting from this growth. Despite the large number of workers required during the construction phase, the number of permanent employees for operation of the plant will be relatively small. Emissions associated with new residential construction, commercial services, and supporting secondary industrial services are not expected to be significant. To the extent that plant draws from the existing work force and is supported by the existing infrastructure, impacts would be minimal and distributed throughout the region.

H. Environmental Assessment

Illinois law does not provide for performance of other environmental impact assessments in conjunction with the issuance of this permit for the proposed plant. Likewise, the issuance of this permit is not a federal action for which an Environmental Impact Assessment would be required under the National Environmental Policy Act.

IX. REQUEST FOR COMMENTS

It is the Illinois EPA's preliminary determination that the draft permits would meet all applicable state and federal air pollution control requirements, subject to the conditions in the draft permit.

Attachment 1 – Summary of Proposed BACT Determinations

Coal Boilers:

Pollutant	Emission Limit	Principal Control Measures
PM	0.015 lb/million Btu, 3-hour ave.	Electrostatic Precipitator (ESP) and Wet Electrostatic Precipitator (WESP)
SO_2	0.182 lb/million Btu, 30-day ave.	Wet Flue Gas Desulfurization (WFGD)
NO_x	0.08 lb/million Btu, 30-day ave.	Low NO_x Burners and Selective Catalytic Reduction (SCR)
CO	0.12 lb/million Btu, 24-hour ave.	Good Combustion Practices
VOM	0.004 lb/million Btu, 3-hour ave.	Good Combustion Practices
Fluorides	0.00026 lb/million Btu, 3-hour ave.	Wet Flue Gas Desulfurization (WFGD) and Wet Electrostatic Precipitator (WESP)
Sulfuric Acid Mist	0.005 lb/million Btu, 3-hour ave.	Wet Flue Gas Desulfurization (WFGD) and Wet Electrostatic Precipitator (WESP)
Lead	Addressed by limitation on PM	Electrostatic Precipitator

Auxiliary Boiler:

Pollutant	Limitation	Control Measures
PM	--	Natural Gas as Sole Fuel
NO_x	0.167 lb/million Btu	Low-NO_x Burners
SO_2	--	Natural Gas as Sole Fuel
CO	0.11 lb/million Btu	Good Combustion Practices
VOM	0.013 lb/million Btu	Good Combustion Practices
Other	--	Natural Gas as Sole Fuel

Material Handling and Other Operations:

Emission Unit	Limitation	Control Measures
Material Processing and Handling Operations	Controlled particulate matter not to exceed 0.01 grain/dscf	Dust Suppression or Enclosure and Baghouses/Filter Devices
Storage Buildings	No visible emissions	Enclosure and Spray Systems at Material Transfer Points
Storage Piles	Not applicable	Covers and Application of Dust Suppressants
Cooling Tower	Design drift rate not to exceed 0.0005 percent	High-Efficiency Drift Eliminators
Plant Roadways and Open Areas	Not applicable	Paving, Vacuum Sweeping and Application of Dust Suppressants

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