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Project Summary for a Construction Permit Application from Christian County Generation, LLC for the Taylorville Energy Center Christian County, Illinois

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I. INTRODUCTION

Christian County Generation, LLC, has submitted an application for a permit to construct the Taylorville Energy Center (TEC), a nominal 630 megawatt (MW) electric power plant to be located approximately 1.5 miles northeast of Taylorville. The plant would use Integrated Gasification Combined Cycle (IGCC) technology with Illinois Basin coal as the design feedstock.

Christian County Generation must obtain an air pollution control construction permit from the Illinois EPA for the proposed plant because the plant would be a source of emissions. The Illinois EPA has reviewed Christian County Generation's application and made a preliminary determination that the application for the proposed project meets applicable requirements. Accordingly, the Illinois EPA has prepared a draft of the construction permit that it would propose to issue for the proposed plant. The Illinois EPA has also prepared a draft Acid Rain Permit for the plant, to address requirements under the federal Acid Rain program. However, before issuing these permits, the Illinois EPA is holding a public comment period with hearing to receive written and oral comments on the proposed issuance of permits and the terms and conditions of the draft permits.

II. PROJECT DESCRIPTION

The proposed power plant would use Integrated Gasification Combined Cycle (IGCC) technology to generate electric power. With IGCC technology, a feedstock is first processed by gasification to produce a synthetic fuel gas (syngas). The feedstock for the proposed plant would be Illinois Basin coal (the Herrin No. 6 coal seam). The syngas from the proposed plant would be a low Btu fuel gas with a heat content of approximately 250 Btu/cubic foot. The principal components of the syngas would be hydrogen and carbon monoxide. This syngas fuel is then burned in separate gas turbine combustion equipment to generate electric power. Electric power is also generated from heat energy recovered as steam from the gasification process.

The plant is being developed to operate as a base load power plant, with each combustion turbine running for months at a time, ideally at or near capacity. The plant would employ two identical "trains," each with half the capacity of the plant. The plant would also have a "spare" third gasifier so that the plant could continue to operate at full capacity during maintenance or outage of either of the gasifiers. This will increases the reliability of electric power generation and the availability of the plant.

After accounting for power consumed in operating the plant, the plant would have a nominal net output of about 630 MW to the grid. The plant would also generate about 140 MW of electricity that would be consumed in operating the plant itself. The nominal heat input of the plant, based on the flow of feedstock into the gasifiers, would be 5,835 million Btu per hour.

Much of the power consumed at the plant would be used in the air separation unit. In this unit, ambient air is separated into oxygen and nitrogen using low temperature refrigeration and high pressure. The oxygen is used in the gasification process, where concentrated oxygen improves process efficiency, as compared to use of air, which is only about 21% oxygen. The pressurized nitrogen stream from the air separation unit is used in the combustion turbines to generate electric power. The introduction of nitrogen into the turbines also lowers the peak flame temperatures in the turbines, which acts to reduce NOx emissions.

The gasification block would have three identical gasifiers (one spare) and two identical, parallel gas cleanup trains, as already explained. Raw syngas would be produced from slurried coal and oxygen in the gasifiers. The raw syngas would then undergo a series of processes in two gas cleanup trains to clean the gas and prepare the raw syngas for use as fuel. These processes would include cooling, removal of entrained particulate matter, mercury removal, and removal of sulfur compounds and other acid gases from the raw syngas. A more detailed description of the gasification process is provided in Attachment 2.

The only direct emissions from the gasifier block would normally occur from the sulfur recovery unit. The sulfur recovery unit further processes the sulfur removed from raw syngas during cleaning, which is collected as hydrogen sulfide (H_2S). The sulfur recover unit converts the H_2S into elemental sulfur, which is a byproduct from the plant that can be sold or stockpiled, depending on current market for sulfur. The emissions of the sulfur recovery are minimized with a tail-gas treatment unit, which recycles most of the exhaust from the sulfur recovery unit back into that unit. The remaining gas stream that is not recycled by the tail gas treatment unit is controlled by a thermal oxidizer, which combusts the stream so that emissions of sulfur occur as SO_2, rather than H_2S.

The gasifier block would also be a direct source of emissions during upsets, when processed syngas could not be sent on to the power block. These upset emissions would occur from a flare, which would be designed to safely combust and dispose of syngas under these circumstances.

After cleaning, the syngas would be supplied to the power block where it would be fired in two combined-cycle combustion turbines to produce electricity. As combined-cycle turbines, the turbines would be followed by heat recovery steam generators, which produce steam from the hot exhaust from the turbines. The heat recovery steam generators would be designed to produce steam from the thermal energy in the turbine exhaust without “duct burners” located between the turbines to boost the temperature of the turbine exhaust before entering the steam generator. The steam from the heat recovery steam generators would be combined with steam from the various heat exchangers in the gasification block and used in a steam turbine to also produce electric power. The turbines would have natural gas firing capability for start-up and emergency or backup operation. The exhaust from each turbine and heat recovery steam generator pair would be vented to the atmosphere through 199 foot high stacks.

Emissions from the power block would be controlled or minimized by using syngas cleanup technologies for control of emissions of particulate matter (PM), mercury, sulfur dioxide (SO_2) and other sulfur compounds. Good combustion practices and of nitrogen injection with its diluent effect and add-on selective catalytic reduction (SCR) systems would be used on the turbines to control carbon monoxide (CO) and nitrogen oxides (NOx) emissions.

Other emission units at the proposed plant would include: storage, processing and handling equipment for coal, slag, and other bulk materials; a cooling tower; an auxiliary boiler; various roads and parking areas; and engines for backup and emergency power for the plant.

III. PROJECT EMISSIONS

The principal emission units at the proposed plant are the two combustion turbines. The potential emissions of the turbines 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 combustion turbines do not operate at their maximum capacity.

Pollutant	Potential Emission (Tons Per Year)
Particulate Matter (PM) - filterable	161
Total Particulate Matter	412
Sulfur Dioxide (SO_2)	299
Nitrogen Oxides (NO_x)	629
Carbon Monoxide (CO)	920
Volatile Organic Compounds (VOC)	28
Fluorides, as hydrogen fluoride	0.61
Sulfuric Acid Mist	67
Mercury	0.038
Hydrogen Chloride	7.5
Lead, as elemental lead	0.02

The plant would also have the potential to emit much smaller amounts of emissions from the gasifiers and other operations at the plant. Thus, the emissions generated at the plant result primarily from the operation of the combustion turbines.

IV. APPLICABLE EMISSION STANDARDS

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

Certain emission units at the proposed plant would also be subject to federal New Source Performance Standards (NSPS), at 40 CFR Part 60. The combustion turbines and associated heat recovery steam generators would be subject to the NSPS for electric utility steam generating units, 40 CFR 60, Subpart Da. The NSPS sets emission limits for nitrogen oxides, sulfur dioxide, particulate matter, and mercury emissions, as well as opacity, from the units. The carbon bed in the syngas cleanup train is designed to reduce mercury emissions by 95%, which should satisfy the mercury emission limit specified by this NSPS. In addition, the combustion turbines may also be subject to certain requirements of the NSPS for gas turbines, 40 CFR 60, Subpart GG.

The auxiliary boiler is subject to the NSPS for non-utility steam generating units, 40 CFR 60 Subpart Db. Various coal handling operations at the plant are subject to NSPS for coal preparation plants, 40 CFR 60, Subpart Y.

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. Because the plant's proposed location is in an attainment area, under PSD, the proposed plant is major for emissions of NOx, SO_2, PM and CO with potential annual emissions of more than 100 tons for each of these pollutants. Under the PSD rules, once a proposed source is major for any PSD pollutant, all PSD pollutants whose potential emissions are above the specified significant emission rates in 40 CFR 52.21(b)(23) are also subject to PSD review. Therefore, the proposed plant is also subject to PSD review for sulfuric acid mist, with potential annual emissions of 67 tons, which exceed the significant emission rate of 7 tons.

B. Maximum Achievable Control Technology (MACT)

Potential emissions of hazardous air pollutant (HAP) from the plant are less than 25 tons per year in the aggregate and less than 10 tons per year for any single HAP. Therefore, the proposed plant is not a major source of HAPs and is not subject to MACT standards, either as adopted by USEPA by rule or as determined on a case-by-case during permitting pursuant to Section 112(g) of the Clean Air Act.

C. Acid Rain Program

The proposed plant is an affected source and the two combustion turbines/heat recovery steam generators 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 SO_2 and NOx, pollutants that contribute to acid rain. Under the Acid Rain program, Christian County Generation would have to hold SO_2 allowances for the actual SO_2 emissions from the affected units. Effectively, the Acid Rain program 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 requirement 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 combustion turbines/heat recovery steam generators would normally qualify as Electrical Generating Units (EGU) for purposes of 35 IAC Part 217, Subpart W, NOx Trading Program for Electrical Steam Generating Units. However, this rule will no longer be in effect once the turbines and the plant itself are operational. This is because Illinois' version of the Clean Air Interstate Rule will take its place.

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, most notably PSD. Christian County Generation would have to apply for its CAAPP permit within 18 months after initial startup of the plant.

VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Under the PSD rules, an applicant for a PSD permit must demonstrate that Best Available Control Technology (BACT) will be used to control emissions of pollutants subject to PSD. Christian County Generation has provided a BACT demonstration in its application addressing emissions of NOx, SO_2, CO, PM/PM_{10} and sulfuric acid mist from the proposed plant.

BACT is defined by Section 169(3) of the federal Clean Air Act 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.

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 unit, 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 for this project is provided in Attachment 1.

A. General Discussion of the Selected Generation Process And Feedstock

Christian County Generation has selected IGCC technology for the proposed power plant, rather than traditional boiler based technology. This decision does not need to be scrutinized as part of the BACT determination for the proposed plant, except as it has a role in the selection of the design coal supply for the plant. The emission levels that are achievable with IGCC technology for different pollutants are generally significantly lower than or comparable to the levels achieved with boiler-based technology. This is because the contaminants present in the coal, e.g., particulate (ash), sulfur and fluorine, are removed from a gaseous fuel stream prior to combustion, rather than after combustion when these contaminants would be present at much lower concentrations. Accordingly coal gasification is one of the most promising electrical generation technologies to reduce emissions, as well as other environmental consequences from new coal-fired power plants. Coal gasification, as recognized by USEPA, USDOE, and other experts, is expected to be at the heart of future generations of clean coal plants, as gasification offers one of the most clean and versatile ways to convert coal into electricity, as well as into substitute natural gas, synthetic fuel oil, and other products. As the proposed plant would be developed with IGCC technology, this also provides an additional basis to support the overall project from a broad environmental perspective, as the plant would facilitate the continued development and commercial application of coal gasification technology for the generation of electricity.

The selection of IGCC technology for the proposed plant does have implications for the BACT determination for the proposed plant as related to the coal feedstock selected for the plant by Christian County Generation. IGCC technology is commonly recognized as being a significantly more expensive technology for generation of electricity than tradition boiler-based generation. This is a key factor in the slow development of IGCC technology in the United States. As a result, the coal feedstock selected by a person proposing to develop an IGCC plant may be critical to the economic feasibility and viability of the proposed project, so as to constitute an essential element of that project. This is the case for the proposed plant, for which Illinois coal, available in the area around the plant, is the design coal supply. It is not appropriate for the BACT determination for this project to specify that an alternative coal must be used that has a lower ash and sulfur content than Illinois coal, such as Western sub-bituminous coal.

The use of an alternative coal feedstock containing less ash and sulfur can be readily eliminated for a number of reasons. Use of low-sulfur bituminous coal would further increase the cost of the proposed plant by over 10 percent, likely making development of the project no longer economically viable. As recognized by USEPA in its *Final Report: Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies*, EPA-430/R-06/006, gasification of sub-bituminous coal is not as efficient as gasification of bituminous coal, which has a higher heat content. This effect significantly increases the predicted capital and operating costs for an IGCC plant that would use sub-bituminous coal, as compared to the costs for a plant using bituminous coal. The work to date in the United States on IGCC technology has been concentrated on plants using high-Btu feedstock. Moreover, an abundant local resource of feedstock is important for the proposed plant to assure a reliable, dependable and affordable supply of feedstock for the plant, as again related to the economic viability of the plant. Finally, the use of such an alternative coal would likely not achieve any further reduction in the emissions of the plant, given the control systems that would be used for emissions of PM, SO_2 and sulfuric acid mist from the plant. The level of emissions achieved by these control systems is not governed by the level of contaminants entering the systems but by the level of contaminants that are allowed to remain in the gas stream leaving the control system. Accordingly, the BACT determination for the plant is appropriately focused on establishing BACT for the plant for the coal feedstock selected by Christian County Generation, rather than on evaluation of alternative feedstocks for the plant.

For similar reasons, it is also not appropriate for the BACT determination for the proposed plant to mandate that the coal feedstock for the plant be "washed" to lower its ash and sulfur content. In addition to not having demonstrated benefits for emissions, a requirement for washed coal would potentially interfere with the efficiency of the gasification process and unnecessarily restrict the selection of feedstock for the plant. In addition, coal washing has associated environmental impacts as it generates solid waste and wastewater and requires that additional coal be mined to make up for material lost in the washing process.

B. BACT Discussions for Gasification/Power Generation

The following discussion addresses BACT for the gasification/syngas cleanup operations and the combustion turbines. These units are addressed together because emissions of pollutants are controlled either with pre-combustion control, by cleanup of the raw syngas, or with combustion/post-combustion control at the combustion turbines, depending on the nature of a particular pollutant.

Particulate Matter (PM)

IGCC plants are a source of PM emissions from the fine slag that is carried from the gasifier with the raw syngas. This fine slag is made up of unreactive mineral compounds and carbonaceous material from the coal feedstock that are not completely gasified. The coarse slag, which makes up the majority of the slag produced by gasification, is captured within the gasifiers and contained and not entrained in the syngas.

For several reasons, IGCC plants use pre-combustion gas cleaning for control of PM emissions. The entrained fine slag in the raw syngas must be removed from the gas prior to the acid gas removal system for ease of operation of this system. Entrained particulate must be also removed from the syngas to prevent excessive wear on the combustion turbines, which are designed to use low-ash fuel like natural gas and distillate oil, rather than coal. There are two basic approaches to the pre-combustion cleaning of raw syngas, scrubbing with water and filtration. Each approach achieves similar level of performance for PM and the selection of approach is largely a consequence of the gasification technology that has been selected rather than a difference in the resulting emission levels.

While technically feasible in a theoretical sense, post-combustion control of PM, by filtration or electrostatic precipitation, has not been attempted at IGCC plants and is not considered a viable control technology option. As a general matter, it is far more efficient and effective to collect PM from the concentrated syngas stream prior to combustion, rather than removing PM from flue gas after combustion. After combustion, there is a much larger volume of exhaust gas that must be processed and the concentration of individual particles in the exhaust is much lower. Also as already noted, since the raw syngas must be cleaned prior to combustion, use of post-combustion control would provide minimal additional reduction in PM emissions, given the effectiveness of pre-combustion control.

Consistent with the approach taken to syngas cleanup by General Electric, the gasification technology supplier for the proposed plant, Christian County Generation has proposed to use scrubbing for control of PM emissions. The ability of countercurrent scrubbing to achieve significant removal of fine particulate and water soluble contaminants from raw syngas to the wash stream is well demonstrated. The Department of Energy’s final project report for the IGCC project at the Polk Power Station indicates that scrubbing effectively controlled not only PM, but also hydrogen chloride (HCl), ammonia and similar soluble contaminants present in the raw syngas. The report also notes that in some instances the PM emissions resulting with scrubbing were only 5 percent of those for a typical coal fired boiler using an electrostatic precipitation.

Filtering of raw syngas can also be performed with dry ceramic or metallic candle filters, which are normally located upstream of the high-temperature heat recovery devices. Barrier filters produces a dry solid as compared to the wet waste from a scrubbing system, as discussed above. The levels of PM emissions achieved by candle filters are similar to those achieved by scrubbers. However, the filters are subject to blinding or breakage, as discussed in several of the status reports for the Wabash River IGCC demonstration project. Dry filtration is also not effective at removing chlorides as are wet scrubber systems.

Efficient chloride removal is important in minimizing deterioration and potential poisoning of the hydrolysis catalyst and corrosion of equipment. Finally, dry material collected by a filter is not as easily as handled as the wet stream with scrubbing.

Because scrubbing and filtration achieve similar levels of PM emissions and filtration poses certain operational concerns for the plant, the Illinois EPA is proposing to accept pre-combustion scrubbing, as proposed by Christian County Generation, as the underlying control technology for BACT for PM emissions. The Illinois EPA has rejected use of post-combustion controls (filtration or electrostatic precipitation) in combination with pre-combustion control as being a theoretical approach to emissions control that should not be attempted at the proposed plant.

For firing syngas, the Illinois EPA is proposing PM BACT limits, in pounds per million Btu on a 3-hour average, of 0.009 for filterable PM and 0.022 for total PM (filterable and condensable), on a 3-hr block average. The format of these limits, i.e., pound per million Btu of heat input (HHV) to the combustion turbines, is selected to be consistent with the format used by USEPA in the NSPS for combustion turbines/heat recovery steam generators boilers, 40 CFR 60, Subpart Da, which would be applicable to these units. This same format is used in conjunction with the BACT limits for other pollutants discussed below.

These limits are more stringent than the PM limits achieved in practice at currently operating IGCC plants. (Refer to Attachment 3.) These limits are also lower than the PM limits for any comparable new coal-fired boiler-based generating unit of which the Illinois EPA is aware. (Note that limits cannot be directly compared, since the limits for the proposed plant reflect only part of the heat input to the plant.)

BACT limits are also proposed for use of natural gas, as the combustion turbines are being developed to be able to fire natural gas as well as syngas. This will allow the plant to continue generation of electricity when syngas is not being produced. BACT for natural gas would be provided by the low level of particulate present in commercial natural gas, rather than cleaning of incoming natural gas. The proposed PM BACT limits for firing of natural gas, in pounds per million Btu on a 3-hour average, are 0.007 for filterable PM and 0.011 for total PM. These limits are intended to reflect the maximum level of emissions that would normally accompany firing of natural gas in the turbines.

<u>Sulfur Dioxide (SO_2) and Sulfuric Acid Mist</u>

As already discussed, sulfur compounds are present as a contaminant in the raw syngas from gasification, as sulfur is present in the feedstock for gasification and carried over into the syngas. If these sulfur compounds, i.e., H_2S and COS, are not removed from the syngas prior to combustion, they are potentially emitted as SO_2 and, to a much lesser extent, as sulfuric acid mist, when the syngas is combusted as fuel. At IGCC plants emissions of these pollutants are controlled prior to combustion by first converting most of the COS to H_2S and then by removing the H_2S and remaining H_2S in the raw gas with an Acid Gas Removal (AGR) system.

Post-combustion control, after the syngas is burned in the combustion turbines, is a technically feasible control technology option for the plant, as well as feedstock selection and pre-treatment. However, since the highest removals of sulfur compounds available are provided by pre-combustion control technologies, the post-combustion technologies, i.e., wet and dry scrubbing were not considered further in the BACT evaluation, either alone or in combination with pre-combustion control. In addition, post-combustion control specifically for sulfuric acid mist was not considered further because effective control of sulfur in the raw syngas also serves to control sulfuric acid mist, which is formed during and after combustion as some of the SO_2 oxidizes into sulfur trioxide (SO_3), which reacts with water to form sulfuric acid mist.

There are currently three basic absorption processes available for pre-combustion removal of sulfur compounds from the raw syngas stream, Selexol™, Rectisol™, and amine-based processes. Selexol™ and Rectisol™ are physical absorption processes that use solvents that rely upon pressure to dissolve sulfur compounds. The absorbed sulfur compounds are then removed from the solvent in a separate step, by depressurization of the solvent in a stripper, and the clean, regenerated solvent is returned to the absorption column. This stripping process also produces a concentrated stream of sulfur compounds that is sent to the sulfur recovery process.

The Selexol™ process uses an inert solvent made of dimethyl ether of polyethylene glycol. The raw syngas enters the Selexol™ unit and is cooled to condense and remove water. The syngas then flows to a countercurrent absorption column where it is introduced to the Selexol™ solvent. Sulfur compounds in the syngas is absorbed into the solvent and clean syngas exits from the top of the column.

The Rectisol™ process uses cold methanol as the solvent. The raw gas entering the unit is cooled, and trace chemical components are removed with a cold methanol pre-wash. Then, sulfur compounds are removed from the raw gas using CO_2-rich methanol. Although the Rectisol™ process has not been used at an IGCC plant, the Illinois EPA is not aware of technical limitations that would make the process infeasible for an IGCC plant.

In amine absorption processes, sulfur compounds in the feed gas are removed by a chemical reaction or bond between the sulfur compounds and an amine in a water solution. The amine solution is then regenerated in a separate step with heat in a stripper tower. Methyldiethanolamine (MDEA) is the most commonly used amine in these systems. Amine absorption is routinely used at petroleum refineries and has been successfully used at existing IGCC plants, so it is a well demonstrated control technolgy option for the proposed plant.

The most effective pre-combustion control technology options for the proposed plant are the Selexol™ and Rectisol™ processes. With appropriate prior treatment of the raw syngas, both processes are capable of removing over 99 percent of the sulfur compounds from the syngas. The feasibility studies performed by vendors of these processes indicate that Selexol™ can achieves 99.8 percent nominal removal of sulfur from the raw syngas and Rectisol™ can possibly achieve 99.9 percent nominal removal. Christian County Generation has selected a Selexol™ system for the proposed plant. Since Rectisol™ has the potential to achieve lower emissions of SO_2 and sulfuric acid mist, Christian County Generation conducted an evaluation of the economic, energy and environmental impacts that would be associated with use of the Selexol™ and Rectisol™ processes. This evaluation shows economic impacts from the Rectisol™ process that support rejection of this process for the proposed plant and acceptance of the use of the Selexol™ process.

The Illinois EPA is proposing use of pre-combustion control of sulfur compounds in the raw syngas, with the Selexol™ process or equivalent, as BACT for control of SO_2 and sulfuric acid mist emissions. The proposed BACT emission limits for firing of syngas in the combustion turbines, in pounds per million Btu on a 3-hr rolling average, are 0.016 for SO_2 and 0.0035 for sulfuric acid mist. These limits are beleibved to be more stringent than the emission limits achieved in practice at currently operating IGCC units and represent a nominal removal efficiency of more than 99+ percent for sulfur, comparing the sulfur in the design coal supply and the required level of sulfur in the cleaned syngas.

As with emissions of PM, separate BACT limits are also proposed for firing of natural gas in the combustion turbines, which may occur when syngas is not being produced or has not been adequately cleaned. BACT for natural gas would be provided by the low level of sulfur present in commercial natural gas, rather than cleaning of incoming natural gas. For firing of natural gas, the proposed SO_2 BACT limit is 0.001 pounds per million Btu on a 3-hr rolling average. This limit is intended to reflect the maximum level of SO_2 emissions that would normally accompany firing of natural gas in the turbines. A separate limit for sulfuric acid mist is not proposed, as the SO_2 limit also serves as a surrogate for control of sulfuric acid mist.

Nitrogen Oxides (NOx)

Emissions of NOx are formed during combustion, from nitrogen contained in the atmosphere that is directly introduced into the combustion turbines as combustion air. Accordingly, BACT for emissions of NOx cannot be addressed with pre-combustion cleaning of raw syngas or use of natural gas as a backup fuel. The BACT determination for NOx must focus on control of emissions during combustion of fuel in the turbines and on post-combustion control. As BACT for NOx, Christian County Generation has proposed the combination of nitrogen diluent injection during combustion and selective catalytic reduction (SCR) to control NOx emissions from the combustion turbines.

The following emission control technologies were reviewed, based on available data, as possible NOx control technology options, in order from most effective to least effective: 1) Selective catalytic reduction (SCR), 2) Diluent injection with nitrogen, and 3) Steam or water injection. Selective Non-Catalytic Reduction (SNCR) and Low-NOx burner design were also considered but rejected as technically infeasible. Review of the USEPA's BACT/RACT/LAER Clearinghouse indicates that nitrogen diluent injection is the NOx control technology commonly used for turbines at IGCC plants.

Selective catalytic reduction (SCR) uses a chemical reaction with a chemical reagent, typically ammonia (NH_3) to remove NOx from a flue gas stream. The reaction between NOx and the reagent, as they pass through a porous ceramic bed impregnated with catalyst, ideally at a temperature in the range of 575 to 750 $^{\circ}$F, reduces NOx back to molecular nitrogen (N_2). Because the turbines at the proposed plant are "combined cycle" turbines equipped with heat recovery steam generators (HRSG), the flue gas from the turbines will be within the necessary temperature range within the HRSG, where the hot exhaust from the temperature is “cooled” to generate steam. SCR is considered very effective in controlling NOx. It is commonly required as BACT for new combined cycle turbines fired with natural gas. This makes SCR a feasible NOx control technology for the turbines at the proposed plant.

Diluent injection with nitrogen is a combustion control technique that reduces the production of thermal NOx during combustion. Nitrogen is injected into the combustors of the turbines, in which the fuel is actually combusted. The nitrogen acts to lower the peak flame temperature and improve mixing, which result in less production of thermal NOx. This is the predominant method of NOx control for IGCC turbines. It is feasible when operating the turbines on syngas because of the availability of nitrogen under high-pressure from the Air Separation Unit during this mode of operation.

Steam or water injection is another combustion control techniques used to reduce the production of thermal NOx, which is similar to nitrogen diluent injection. However, it involves injecting steam or water into the combustors on a turbine to reduce the production of thermal NOx. Steam and water injection have been used to reduce NOx emissions from natural gas fired combustion turbines. It is not as effective in controlling as SCR, as it can cause combustion “noise” at the level of injection needed to approach the effectiveness of SCR. This noise affects turbine operation, causing flame instability, and vibrations that accelerate wear. Steam and water injection also reduce the fuel efficiency of a turbine increase, requiring combustion of additional fuel to compensate for the lowered efficiency. This is because of the additional fuel needed to produce the steam or the heat consumed in evaporating the injected water. Lastly, for large utility-scale combustion turbines, of the size of those at the proposed plant, when fired with natural gas, similar levels of NOx control can be achieved with combustor design.

Low-NOx combustor design is a combustion control technology routinely used for natural gas fired combustion turbines. This technology relies on carefully managing the mixing of the natural fuel and combustion air prior to an in the combustor to minimize peak flame temperatures. This technology is most effective for large utility-scale turbines, in which the combustors are large enough to be designed to both minimize peak flame temperatures while maintaining efficient combustion of fuel. However, the heat content of the syngas fired in the proposed turbines will only be about 250 Btu per standard cubic foot (scf), compared to the heat content of natural gas at about 1,000 Btu per scf. As a result, conventional low NOx combustor design is not an available control technology for the proposed turbines, as it would interfere with stable and efficient combustion of syngas. In addition, the low-Btu content of syngas generally acts to reduce formation of NOx during combustion, as compared to firing of natural gas. While the turbines will also have the capability to fire natural gas as a backup fuel, the design of the combustors is determined by and restricted by the firing of syngas.

Selective Non-Catalytic Reduction (SNCR) is another post-combustion control technology using injection of a chemical reagent, either ammonia or urea, similar to SCR but without a catalyst. Because a catalyst is not used, higher temperatures in the range 1600 to 2000 °F, are needed for the reagent to selectively react with NOx to reduce it back to N_2. SNCR is not a feasible control technology because the temperature of the exhaust, as it exist the turbine is below the needed minimum temperature. In addition, the control efficiency of SNCR is lower than that of SCR. Finally, as SNCR does not use a catalyst, levels of reagent must be used to achieve high levels of NOx control, which poses greater potential for ammonia slip, i.e., emissions of unreacted ammonia from a unit.

The Illinois EPA is proposing the use of a combination of nitrogen diluent injection and selective catalytic reduction as the BACT control technology for emissions of NOx from the combustion turbines. The proposed BACT limits, in pounds per million Btu heat input on a 24-hour average basis are 0.034 for syngas and 0.025 for natural gas. A slightly lower NOx BACT limit is possible for natural gas because it has a significantly higher heat content than syngas, so is more easily combusted.

Carbon Monoxide (CO)

Like NOx, CO emissions are formed during combustion of fuel in the combustion turbines. CO emissions are a result of incomplete combustion of fuel. The feasible control technologies are 1) High levels of excess air and 2) Design of the combustion process and good combustion practices to minimize the formation of CO. A large amount of excess air in the combustion turbines could theoretically reduce CO emissions by raising the amount of oxygen available to provide complete oxidation of CO to CO_2. Use of this technique would have the adverse environmental impact of increasing emissions of other pollutants, particularly thermal NOx, which is supported by excess air.

The Illinois EPA is proposing good combustion practices, i.e., proper operation and maintenance of the combustors in the turbines, and CO emission limits, in pounds per million Btu on a 24-hour rolling average, of 0.049 for syngas and 0.045 for natural gas. A slightly lower CO BACT limit is possible for natural gas because it has a higher heat content than syngas and is more easily combusted. The proposed BACT limits are supported by recent permits and applications for IGCC projects.

Startup. Shutdown and Malfunction

The above BACT emission limits are intended to apply only during normal operation of the gasification and power generation units. Alternative work practice requirements and secondary BACT limits, expressed in pounds per hour, are proposed for periods of startup, shutdown and malfunction. A number of factors preclude imposition of BACT limits expressed in pounds per million Btu during such periods. These include: 1) the complexity of an IGCC plant, in which syngas is produced for immediate use in the combustion turbines, 2) the stringent levels of control that are normally required of the units, 3) the required use of nitrogen diluent injection and SCR for the turbines, which need appropriate operating conditions in the turbines for effective control of emissions, and 4) the limited operational experience with IGCC plants. An alternative approach to these periods is needed that recognizes the inherent technological limitations of gasification and associated syngas cleanup technologies to provide comparable control of emissions during periods of startup, shutdown and malfunction, as compared to periods of normal operation.

The required BACT work practices during periods of startup, shutdown and malfunction are intended to assure that appropriate measures are taken during such periods to minimize emissions. For this purpose, the draft permit establishes both certain basic measures that must be used as well as a general approach to minimization of emissions through formal operating and maintenance procedures, which may be refined based on actual operating experience at the plant. One key element of the basic measures is that natural gas must be used for pre-heating gasifiers during startup. Another key element is that syngas that is used as fuel in the combustion turbines must have been processed by the cleanup train. "Off-specification" syngas, as would be produced during startup or shutdown of the gasifiers and associated cleanup train or during a malfunction of the cleanup trains must be safely disposed of by flaring, rather than by use as fuel. To generate electricity during periods when "off specification" syngas is being produced, Christian County Generation it would have to fire natural gas in the combustion turbines. Incidentally, even though off-specification gas must be flared, it is expected that most flared syngas will still have been subjected to some level of gas cleanup, especially as PM cleanup with water scrubbing is the initial step in the syngas cleanup train.

The secondary BACT limits for periods of startup, shutdown and malfunction, which are expressed in pounds per hour, are imposed to protect air quality. They set a cap or ceiling on allowed emissions, consistent with USEPA guidance for setting BACT for periods of startup, shutdown and malfunction.

B. BACT Discussion for the Sulfur Recovery Units

The sulfur recovery units process the concentrated H_2S stream from the regeneration step in the acid gas recovery systems to produce elemental sulfur. The sulfur recovery units are sources of SO_2 emissions because not all the sulfur present in these streams can be converted into sulfur and a small amount of the sulfur is emitted as SO_2. The basic technology for sulfur recovery plants, the Claus Process, is well established as the process is over 100 years old. Claus sulfur recovery units are routinely used at petroleum refineries to process H_2S streams that are generated from the desulfurization of gasoline, fuel oil, and other petroleum products.

Emissions of SO_2 are minimized by use of a Tail Gas Treatment Unit after the main sulfur recovery unit. This unit functions to recovers additional sulfur from the concentrated H_2S stream, beyond that recovered by the Claus Unit itself. The remaining stream after the Tail Gas Treatment Unit, which contains the organic compounds carried over with the original H_2S stream and the residual unrecovered H_2S, is directed to a thermal oxidizer. The thermal oxidizer controls this final stream, so that sulfur is emitted as SO_2, rather than as H_2S, as is preferable for safety reasons.

The proposed BACT limit for the sulfur recovery units is 100 ppm SO_2 by volume, at zero percent oxygen equivalent, in the exhaust from the thermal oxidizer. This is the performance requirement established for sulfur recovery plants at a number of petroleum refineries in recent Consent Decrees entered into by the operators of those refineries and USEPA. These Consent Decrees are believed to reflect the current capabilities of Tailgas Treatment Units. By way of comparison, the NSPS standard for Claus Units at petroleum refineries, 40 CFR 60.104((a)(2)(i) is 250 ppm.

The above BACT emission limit is intended to apply only during normal operation of the sulfur recovery unit. Alternative work practice requirements and a secondary BACT limit, expressed in pounds per hour, are proposed for periods of startup, shutdown and malfunction. As with the gasification units and combustion turbines, number of factors preclude imposition of BACT limits expressed in pounds per million Btu during such periods. Most significantly, the basic sulfur recovery unit and tail gas treatment are sophisticated chemical processes, which cannot achieve the same level of performance during the transitory conditions of startup, shutdown or malfunction, as achieved during stable operation. An alternative approach to these periods is needed that recognizes the inherent limitations of these units. The required BACT work practices during periods of startup, shutdown and malfunction are intended to assure that appropriate measures are taken during such periods to minimize emissions.

C. BACT Discussion for the Natural-Gas Fired Auxiliary Boiler

The natural gas fired auxiliary boiler would be used to produce the steam that is needed for the startup of the gasifiers. It would not normally operate at other times and the operation of the boiler is constrained to no more than 500 hours.

Good combustion practices and current low-NOx burner technology are proposed as BACT. Given the nature of the auxiliary boiler, including infrequent and intermittent operation, additional control measures are not practical for the auxiliary boiler. The proposed BACT limits, on a 24-hour average basis, are 0.036 and 0.037 pounds per million Btu for NOx and CO, respectively. BACT limits are proposed for only these pollutants as necessary to address the performance of the low-NOx burners for the pollutants that are affected by combustion, NOx and CO.

D. BACT Discussion for Cooling Tower

As with any power plant that uses steam to generate electricity, a cooling system is used to condense and recover the steam after it leaves the steam turbine. Christian County Generation has proposed a wet cooling tower, in which cooling is achieved by evaporation of water. High-efficiency drift eliminators and dry cooling were considered for controlling PM emissions from the cooling tower.

Direct dry cooling systems use air to directly condense steam, whereas indirect dry systems use a closed loop water system to condense steam and the resulting heated water is then air cooled. Such dry cooling systems transfer heat to the atmosphere without significant loss of water. However, these systems require a large amount of power to operate the many fans needed to move the air through the unit. There can also be nuisance noise associated with these fans. The extra equipment needed and the significant increase in parasitic electricity consumed to operate that equipment, acts to increase emissions of a plant as additional fuel must be consumed to supply this electricity. This renders dry cooling inappropriate when the location of a proposed project and available water resources make it amenable to wet cooling.

Because dry cooling has been rejected as a control technology option for the cooling tower, the use of high-efficiency drift eliminators is proposed as BACT for the cooling tower. High-efficiency drift eliminators act to control PM emissions by minimizing the drift or loss of water droplets from the cooling tower. These droplets are the source of PM emissions from a cooling tower, since mineral material present in the droplet is emitted as PM when an entire droplet escapes the cooling tower and completely evaporates in the atmosphere.

E. BACT Discussion for Material Handling

Christian County Generation has proposed a variety of measures, including use of baghouses and implementation of work practices to control both so-called "stack" and "fugitive" emissions, from handling of material with the potential to generate dust. The proposed BACT determination for PM emissions from coal and slag handling is intended to require that PM emissions be effectively controlled while still providing appropriate operational flexibility in the manner with which this is accomplished in practice by the plant. This general approach has been taken because of the Illinois EPA's experience with material handling operations and associated control measures at coal-fired power plants, which is that these operations change over time as equipment ages and new systems, devices and techniques become available. These types of changes can also occur during the detailed design and construction of a project, as new approaches to material handling operations are identified and impediments to the initial plans are identified. Accordingly, material handling operations at the proposed plant are most efficiently and consistently addressed from an administrative perspective through establishment of generic BACT control requirements, rather than with separate requirements for each individual operation.

For this purpose, the draft permit delineates three categories of material handling operations: 1) Dry material handling, other than storage piles, 2) Storage piles for dry materials, and 3) Handling of wet materials. BACT for the first category of operations, handling of dry materials, other than storage piles, is proposed as enclosure to prevent visible emissions. In addition, if PM emissions are aspirated to a control device, a filter or baghouse device must be used unless consideration of operational safety dictates another type of control device, use of a filter-type device is required. This approach has been taken as filtration is generally considered the most effective active control technology for control of dust from material handling operations at power plants. Filters control PM emissions by passing dust-laden air through a bank of filter tubes suspended in the gas flow stream. A filter "cake", composed of captured particulate, builds up on the "dirty" side of the filter. Periodically, the dust cake is removed through a physical mechanism (e.g., a blast of compressed air from the "clean" side of the filter), which causes the dust to fall into a hopper or back into the silo. The proposed approach for this category of operations requires very effective control of PM emissions, as control of fugitive emissions is addressed by the prohibition against visible emissions and control of stack emissions is addressed by the requirements and minimum performance specifications for control devices.

For storage piles of dry materials, which are potential sources of fugitive PM emissions, two alternative performance standards are proposed as BACT, either the absence of visible emissions or a dust control program that achieves at least 90 percent nominal control of emissions. Given the size of the plant property and location in an agricultural area, the BACT determination need not require storage of bulk dry materials in buildings or silos. The proposed approach allows a variety of suppression or elimination techniques to be used to control emissions, including partial or total enclosure, adjustable feeders and drop systems, and compaction and/or chemical or wet suppression, as appropriate to address the storage of particular dry materials. This approach requires very effective control of PM emissions related to storage piles as control of fugitive emissions is addressed by the prohibition against visible emissions or a minimum performance specifications for the overall effectiveness of control measures, i.e., 90 percent control

For handling of wet materials, the performance standard proposed as BACT is absence of visible emissions, accompanied by timely collection of any spilled material that could become airborne after it dried. Aspiration of dust to control devices is not addressed as the moisture in the material must be sufficient to prevent direct emissions. As with storage piles, this approach allows a variety of suppression or elimination techniques to be used along with the moisture present in a material, including partial or total enclosure and compaction and/or chemical or wet suppression, as appropriate to address the handling of particular wet materials. This approach requires very effective control of PM emissions from wet material handling operations, as control of fugitive emissions is addressed by the prohibition against visible emissions and the further requirement to take actions to prevent secondary emissions from spilled material.

F. BACT Discussion for Roadways and Open Areas

Christian County Generation has proposed a variety of measures, including paving (roadways), dust suppression, sweepers and vacuum trucks, to control emissions of fugitive dust from truck traffic on plant roads. The proposed BACT determination for roadways is intended to require that these emissions be effectively controlled while still providing appropriate operational flexibility in the manner with which this is accomplished in practice by the plant. This general approach has been taken because of the Illinois EPA's experience with fugitive dust control programs. This experience indicates that dust control programs must be flexible to appropriately respond to changing operation and the weather (rain, hot, dry weather in the summer, and snow and ice in the winter). In addition, dust control programs change and evolve over time as new control techniques and service providers become available to control emissions. Accordingly, like material handling operations, roadways at the proposed plant are most appropriately addressed through establishment of broad BACT control requirements, rather than with detailed, prescriptive requirements for control of emissions.

For this purpose, the draft permit proposes two types of BACT requirements for roadways, an opacity requirement and a number of work practice requirements. First, control measures must be used such that opacity of emissions from truck traffic on roadways and windblown dust does not exceed 15 percent. (This requirement would not apply during high wind speed, defines as wind speed in excess of 25 miles per hour, as provided by 35 IAC 212.314.) Second, the required work practices for control of fugitive dust must include: 1) paving of regularly traveled roads; 2) treatment of roads for effective control of emissions, to meet minimum nominal levels of control of emissions; and 3) handling of collected dust in a manner that prevents it from being release back into the environment. This approach requires very effective control of PM emissions from roadways, as control of emissions is addressed both by a numerical opacity standard, which may be readily enforced by any qualified opacity observer, and by specific requirements and performance standards for the fugitive dust control program.

G. BACT Discussion for Backup and Emergency Engines

Backup and emergency engines are used at power plants to provide emergency power for critical activities involved in operating the plant when the regular supply of electricity is interrupted. The most common examples of such engines are engines that provide power for the pumps that supply water for the fire protection system. As such, these engines operate on a limited basis, when they are exercised to verify their readiness for required service and on those uncommon occasions when they are actually needed for their particular function. Accordingly, emissions of these engines are inherently small and are appropriately controlled by limiting the magnitude of potential operation of the engines and by specifying the type of fuel that may be used, rather than by requiring specific emission control methods.

For the proposed plant, BACT is proposed as natural gas as the sole fuel for the main fire water pump. Engines that are not fired on natural gas, but have their own independent fuel oil supply are limited to operation as emergency engines, as defined by 35 IAC 211.1920, and to operation for no more than 500 hours annually in the absence of specific approval by the Illinois EPA.

VII. AIR QUALITY ANALYSIS

A. Introduction

The previous discussions addressed emissions and emission standards. Emissions are the quantity of pollutants emitted by a source, as they are released to the atmosphere from various emission units. Standards are set limiting the amount of these emissions as a means to address the presence of contaminants in the air. The quality of air that people breathe 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 or other emission point, in combination with pollutants emitted from other nearby sources and background pollutant levels. The level of 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 in micrograms per cubic meter, which are millionths of a gram by weight of a pollutant contained in a cubic meter of air.

The United States EPA has established standards for the level of various pollutants 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 USEPA compiles scientific information on the potential impacts of the pollutant into a “criteria” document. Hence the pollutants for which air quality standards exist are known as criteria pollutants. Based upon the nature and effects of a pollutant, appropriate numerical standards(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. In an attainment area, like Christian County, the goal is 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 air 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, NOx, 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, PM and CO

An ambient air quality analysis was conducted by a consulting firm, Kentuckiana Engineering, on behalf of Christian County Generation 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 following tables summarize the results of the analysis (Tables 1 through 3).

The starting point for determining the extent of the modeling necessary for this proposed plant was evaluating whether the 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 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 the proposed plant and significant stationary sources in the surrounding area.

Table 1: Preliminary Impact Analysis
(Significant Impact Assessment)

Pollutant	Averaging Period	Maximum Modeled Impact[a] (ug/m3)	Significant Impact Level (ug/m^3)	NAAQS (ug/m^3)
NO_x	Annual	0.66	1	100

SO_2	3-Hour	38.0	25	1,300
	24-Hour	8.90	5	365
	Annual	0.35	1	80
PM_{10}	24-Hour	25.77	5	150
	Annual	1.22	1	50
CO	1-Hour	115.40	2,000	40,000
	8-Hour	51.16	500	10,000

Notes:

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

The preliminary impact analysis showed maximum concentrations for PM_{10} (24-hour and annual) 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 emissions of the proposed plant and the emissions of existing sources in the area. Background levels of air quality, as determined at ambient monitoring stations operated by the Illinois EPA, were also included in the final results for the NAAQS analysis. These full impact analyses yielded modeled concentrations that were in compliance with the applicable PSD increments and the NAAQS, as shown Table 2 and Table 3, respectively.

Table 2: PSD Increment Consumption Modeling Results

Pollutant	Averaging Period	PSD Increments (ug/m^3)	Maximum Concentration (ug/m^3)
SO_2	3-Hour	512	27.57[a]
	24-Hour	91	6.17[a]
	Annual	20	0.35[b]
PM_{10}	24-Hour	30	14.82[a]
	Annual	17	1.26[c]

Notes

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

b. Data provided for general information, as the annual SO_2 impact of the plant is not significant.

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

Table 3: NAAQS Modeling Results

Pollutant	Averaging Period	NAAQS (ug/m^3)	Background Concentration (ug/m^3)	Max. Modeled Concentration (ug/m^3)	Total Concentration (ug/m^3)
SO_2	3-Hour	1300	330.12[a]	408.16[b]	738.28
	24-Hour	365	115.28[a]	85.29[b]	200.57
	Annual	80	10.48	12.01[c, d]	22.49
PM_{10}	24-Hour	150	53.00[a]	76.53[e]	129.53
	Annual	50	22.97[a]	5.06[c]	28.03

Notes

a. Highest concentration for the Sangamon ambient air quality monitor (2003/2004) for SO_2 and the Macoupin ambient air quality monitor (2003/2004) for PM_{10}.

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

c. Highest 1st high value based upon individual evaluation of each year of the 5-year meteorological dataset.

d. Data provided for general information, as the annual SO_2 impact of the plant is not significant.

e. Highest 6th high value based upon individual evaluation of each year of the 5-year meteorological dataset.

C. Air Quality Analysis for Non-Criteria Pollutants

Christian County Generation also submitted an air quality impact analysis for emissions of certain non-criteria pollutants from the proposed plant. The results (24-hour average impacts for mercury, beryllium, and fluorides) were evaluated by comparing them against monitoring de minimus levels. This analysis used meteorological data for 1986, 1987, 1989, 1990 and 1991, like the analysis for criteria pollutants.

Table 4: Non-Criteria Pollutant Modeling Results

Fluorides		Mercury		Beryllium	
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)
0.0104	0.25	0.00137	0.25	0.0000695	0.001

Notes

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

D. Vegetation and Soils Analysis

Christian County Generation provided an analysis of the impacts of the proposed plant on vegetation and soils. The first stage of this analysis focused on the use of modeled air concentrations and published screening values for evaluating exposure to flora from selected criteria pollutants (SO_2, NOx, CO, ozone and PM_{10}). 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 vegetation 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 and plants. 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 SO_2, NOx, 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 the 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 endangered. These discussions also address endangered species of animals that may be present in the area.

E. Construction and Growth Analysis

Christian County Generation provided a discussion of the emissions impacts resulting from residential and commercial growth associated with construction of the proposed plant. Anticipated emissions resulting from residential, commercial, and industrial growth associated with construction and operation of the proposed plant are expected to be low. Despite the large number of workers required during the construction phase and a significant number of permanent employees for operation of the plant, emissions associated with new residential construction, commercial services, and supporting secondary industrial services are not expected to be significant. To the extent that the plant draws from the existing work force and is supported by the existing infrastructure, impacts would be minimal and distributed throughout the region.

F. 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.

VIII. DRAFT PERMIT

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 to accompany those requirements, including requirements for emissions testing, continuous emissions monitoring, recordkeeping, and reporting.

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

Gasifiers with Flare and Sulfur Plant and Combustion Turbines(CTs):

Pollutant	Principal Control Measures	Limit
Normal Operation with Syngas		
PM - Filterable	Syngas cleaning, with water scrubbing	0.009 lb/million Btu, 3-hour ave.
PM_{10} Total	Syngas cleaning, with water scrubbing and acid gas removal	0.022 lb/million Btu, 3-hour ave.
SO_2	Syngas cleaning, with Selexol process or equivalent	0.016 lb/million Btu, 3-hour ave.
Sulfuric Acid Mist	Syngas cleaning, with Selexol process or equivalent	0.0035 lb/million Btu, 3-hour ave.
NO_x	Diluent nitrogen injection and selective catalytic reduction	0.034 lb/million Btu, 24-hour ave.
CO	Good combustion practices	0.049 lb/million Btu, 24-hour ave.
Startup, Shutdown and Malfunction		
All Pollutants	Flaring of syngas and work practices to minimize emissions	secondary limits, in pounds/hour
Normal Operation with Natural Gas		
PM - Filterable	Natural gas	0.007 lb/million Btu, 3-hour ave.
PM_{10} Total	Natural gas	0.011 lb/million Btu, 3-hour ave.
SO_2	Natural gas	0.001 lb/million Btu, 3-hour ave.
Sulfuric Acid Mist	Natural gas	-----
NO_x	Selective catalytic reduction	0.025 lb/million Btu, 24-hour ave.
CO	Good combustion practices	0.045 lb/million Btu, 24-hour ave.

Sulfur Recovery Unit

Pollutant	Principal Control Measures	Limit
Normal Operation		
SO_2	Tailgas treatment unit followed by thermal oxidixation	100 ppm by volume (dry basis) at 0% oxygen, 3-hour average
Startup, Shutdown and Malfunction		
All pollutants	Flaring of syngas and work practices to minimize emissions	secondary limits, in pounds/hour

Auxiliary Boiler:

Pollutant	Control Measures	Limitation
PM	Natural gas fuel	-----
NO_x	Low-NO_x burners	0.036 lb/million Btu
SO_2	Natural gas fuel	-----
CO	Good combustion practices	0.037 lb/million Btu

Material Handling Operations:

Emission Unit	Control Measures	Limitation
Material Processing, Transfer Buildings, and Handling Operations	Enclosures, baghouses or vent filters, use of dust suppressants	-----
Coal Storage Pile and Associated Handling Operations	Compaction Suppressants Reduced Drop Heights Stacking Tubes Use of Dust Suppressants	-----

Other Operations:

Emission Unit	Control Measures	Limitation
Cooling Tower	0.0005% Drift Eliminators	-----
Roadways and Open Areas	Paved Roads where practicable, dust control program	-----
Emergency/Backup Engines	Limited operation and fuel selection	-----

Attachment 2 - Detailed Description of the Integrated Gasification Combined Cycle (IGCC) technology at the Proposed Plant

The core of the proposed plant is the production of syngas in the gasification block. The gasification block at TEC will have three gasifiers, each unit designed to produce 50% of the raw syngas required for the plant when operating at maximum load. The third gasifier allows for continued syngas supply and operation of the plant at capacity during periods of gasifier maintenance or other gasifier outages, which serves to enhance plant reliability and availability.

The key components of the gasification block are as follows:

Process	Sub-Process	Control Measures
Gasifiers	Normal operation	Not applicable
	Startup, shutdown and upset	Flare
Syngas Cleanup	Particulate removal – Water scrubbing	Not Applicable
	Mercury removal - **Carbon bed**	
	Acid gas removal – scrubbing with Selexol process	
Support Facilities.	Sulfur recovery plant	Tailgas treatment and thermal oxidizer
	Air separation unit (ASU)	

The gasifiers will operate using the General Electric oxygen-blown, entrained flow process. This process includes coal slurry and oxygen feed systems, gasifier reaction chambers, and syngas cooling. The coal feedstock is fed to the gasifiers through a feed injector that mixes the coal slurry and oxygen for effective dispersion of feedstock into the gasifier and efficient operation of the gasifiers. The slurry and oxygen feeds to the injector are controlled by a series of valves to facilitate safe shutdown in case of upsets.

The gasifiers are designed to operate at high pressure and at temperatures between 2300 and 2700 °F. The gasifiers operate in an oxygen deficient mode to facilitate the physical processes and chemical reactions which produce the syngas, rather than combust the coal. The syngas from the gasifiers has a heat content of approximately 250 Btu per standard cubic foot and is composed mainly of hydrogen (H_2), carbon monoxide (CO), steam or water vapor (H_2O) and carbon dioxide (CO_2).

In addition to syngas, the gasifiers also produce a coarse vitreous slag, which comes out the bottom of the gasifiers. This slag contains most of the mineral or ash matter in the coal, which is not converted into syngas and is not transported out or entrained in the syngas leaving the gasifiers. At the high temperatures in a gasifier, this material melts and flows to the bottom of the gasifier. The molten slag is removed from the gasifier through a lock-hopper. The slag is then transported to the slag handling operations. The slag solidifies into a stable glassy frit with very small amounts of residual carbon. The slag is dewatered and transported by truck for sale as a by-product or to an onsite landfill for storage.

When the syngas leaves the gasifier, it first passes through a heat exchanger, the Radiant Syngas Cooler (RSC), that uses the high temperature of the syngas leaving the gasifiers to produces high pressure steam. This increases the efficiency of the plant by recapturing up to 15 percent of the heating value of the coal feedstock at this point in the gasification process. Prior to leaving the gasifier, syngas contacts a water pool (quench section) located at the bottom of the unit, which enhances collection of the coarse slag.

The raw syngas leaving a gasifier contains entrained fine slag. It also contains significant amounts of several undesirable compounds, including hydrogen sulfide (H_2S), carbonyl sulfide (COS) and hydrogen chloride (HCl). Because of the fine slag and other undesirable components in the raw syngas, the raw syngas must undergo cleanup prior to use as fuel in the combustions turbines. Removal of fine slag and other undesirable components is done in a series of gas cleaning processes.

Fine slag is removed from the raw syngas first, to further cool the raw syngas and protect the subsequent gas cleanup processes. The syngas is scrubbed with water to remove entrained particles of fine slag. During this scrubbing process, hydrogen chloride (HCl), which is formed from the chlorine contained in the coal, is also removed from the raw syngas. The fine slag is comprised of unreactive mineral compounds and carbonaceous material from the coal that is not completely gasified. The dirty or "black" scrubbing water is flashed to lower temperature and pressure and concentrated in the fine slag handling system. The concentrated slurry is then recycled back into the gasifiers, by being introduced into the coal grinding and feed system.

The syngas from the scrubber goes to the hydrolysis reactor. A small percentage of the sulfur in the coal feedstock is converted to carbonyl sulfide (COS) during gasification. In the hydrolysis reactor, a catalyst is used to react the COS with water (H_20) present in the syngas and convert the COS to hydrogen sulfide (H_2S). The COS must be converted into H_2S because the downstream acid gas removal system is unable to remove COS from the syngas. The hydrolysis process enables the acid gas removal system to remove more than 99 percent of the sulfur in the raw syngas, which would otherwise be emitted as SO_2 when the syngas were burned.

The partially cleaned syngas from the hydrolysis process passes through a series of heat exchangers, the <u>L</u>ow <u>T</u>emperature <u>G</u>as <u>C</u>ooling (LTGC) system, to cool the gas to near ambient temperature. The LTGC system removes liquids or process condensate from the raw syngas, as the gas is further conditioned or prepared for the mercury and H_2S removal processes. The cooled syngas then passes through a carbon bed which removes the mercury as well as certain other trace contaminants from the syngas.

The next step in the gas cleanup train is the Acid Gas Removal (AGR) system for collection of H_2S and other acid gases from the raw syngas. The proposed plant will have a Selexol™ AGR system, using a solvent made of dimethyl ether or polyethylene glycol and a countercurrent absorption column in which solvent is introduced in the top of the column. As the syngas moves upward through the column, the acid gases are adsorbed in the solvent, with clean syngas exiting from the top of the column. The clean syngas exiting the absorber column passes through a knockout drum and demister to remove any entrained solvent. The syngas is then reheated by passing through the highest temperature LTGC exchanger and sent to the combustion turbines.

In a related process for the AGR system, the acid gas rich solvent collected at the bottom of the absorber is continuously regenerated, to strip the H2S from the solvent. The concentrated H_2S stream from this regeneration process goes to the sulfur recovery unit.

The plant is being designed with one flare for the gasification block. The flare will be used to burn non-specification syngas during startup and on-specification syngas during short-term outages of a combustion turbine. All flared syngas will have been treated by the mercury removal and AGR systems prior to flaring. The flare will not operate during normal operation of the gasifiers.

SULFUR RECOVERY UNIT

The H_2S, captured in the AGR system is sent to the sulfur recovery unit, which recovers the sulfur as elemental sulfur, using the Claus process. The recovered sulfur is a saleable byproduct and is processed for offsite use. The remaining tail gas from the Claus Unit is sent to a tail gas treatment unit where additional sulfur is recovered and the overhead gas is destroyed by thermal oxidation.

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AIR SEPARATION UNIT

Oxygen for the gasifiers is produced at the plant in an Air Separation Unit (ASU). The ASU use very cold refrigeration to separate ambient air into oxygen (O_2) and nitrogen (N_2). The oxygen stream is in excess of 95% purity (at least 95% O_2 and no more than 5 % N_2), as required for efficient operation of the gasifiers and the plant. The nitrogen stream from the ASU is also used in the combustion turbines, recovering the pressure energy. As the nitrogen also serves as combustion diluent, it also assists in controlling the NO_x emissions from the combustion turbines.

Attachment 3: Emissions Data for Coal-based IGCC Projects
(from Table 4-5 of the application)

Project	Size (MW)	Status	Permitted and Proposed Limits/ Tested Emissions (lb/million Btu)					
			PM[a]	SO2	NOx	CO	VOM	Acid Mist
Taylorville Energy, Taylorville	677	Application	**0.0090**	**0.016**	**0.034**	**0.049**	**0.006**[b]	**0.0035**
Tampa Electric, Florida	260	Operating	0.13/ 0.037	0.17	0.08	0.041	0.0012	-
Wabash River, Indiana	262	Operating	0.005[c]/ 0.012	0.10	0.15	– /0.056	–/ 0.0021	-
Kentucky Pioneer, Kentucky	394	Permit (Cancelled)	0.011	0.032	0.0735	0.032	0.0044	-
Global Energy-Lima, Ohio	580	Draft Permit	0.010	0.021	0.097	0.137	0.0082	-
Elm Road, Wisconsin	600	Application (Cancelled)	0.011	0.03	0.06	0.03	0.0017	0.0000 5

Notes

a. Filiterable particulate matter.
b. Maximum emissions provided for informational purposes, even though the Taylorville Energy Center is not subject to BACT for VOM.
c. PM Emission limit not met, with highest tested emissions reported at 0.012 lb/mmBtu.