ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
BUREAU OF AIR
PERMIT SECTION

JUNE 2007

RESPONSIVENESS SUMMARY FOR PUBLIC QUESTIONS AND COMMENTS ON THE CHRISTIAN COUNTY GENERATION'S TAYLORVILLE ENERGY CENTER POWER PLANT PROJECT NEAR TAYLORVILLE

Source Identification No.: 021060ACB
Application No.: 05040027

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Exhibit 3

DECISION

On June 5, 2007, the Illinois Environmental Protection Agency (Illinois EPA) issued an air pollution control construction permit to Christian County Generation, LLC, for a proposed coal-fired power plant at 1630 North 1400 East Road, near Taylorville, Illinois.

Copies of the documents can be obtained from the contact listed at the end of this document. The permits and additional copies of this document can also be obtained from the Illinois EPA website www.epa.state.il.us/public-notices/.

BACKGROUND

On April 14, 2005, the Illinois EPA, Bureau of Air received an application from Christian County Generation, LLC, requesting a permit to construct an Integrated Gasification Combined Cycle (IGCC) power plant, located about two miles north of Taylorville, Illinois. The plant would have three gasifiers with two associated gasification cleanup trains, two combustion turbines, a sulfur recovery plant and various ancillary and support operations.

The construction permit issued for the project identifies the applicable rules governing emissions from the plant, and establishes enforceable limitations on its emissions. The permit also establishes appropriate compliance procedures, including requirements for emissions testing, continuous emission monitoring, recordkeeping, and reporting. Christian County Generation will be required to carry out these procedures on an ongoing basis to demonstrate that the plant is operating within the limitations established by the permit and that emissions are being properly controlled.

COMMENT PERIOD AND PUBLIC HEARING

The Illinois EPA Bureau of Air evaluates applications and issues permits for sources of emissions. An air permit application must appropriately address compliance with applicable air pollution control laws and regulations before a permit can be issued. Following its initial review of Christian County Generation's application, the Illinois EPA Bureau of Air made a preliminary determination that the application met the standards for issuance of a construction permit and prepared a draft permit for public review and comment.

The public comment period began with the publication of a notice in the Taylorville Breeze Courier on November 27, 2006. The notice was published again in the Taylorville Breeze Courier on December 4 and 11, 2006.

A public hearing was held on January 11, 2007, at the Taylorville High School to receive oral comments and answer questions regarding the application and draft air permit. The comment period closed on February 10, 2007.

AVAILABILITY OF DOCUMENTS

The permit issued to Christian County Generation and this responsiveness summary are available on the Illinois Permit Database at www.epa.gov/region5/air/permits/ilonline.htm (please look for the documents under All Permit Records (sorted by name), PSD/Major NSR Records). Copies of these documents may also be obtained by contacting the Illinois EPA at the telephone numbers listed at the end of this document.

APPEAL PROVISIONS

The permit being issued for the proposed project grants approval to construct pursuant to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. Accordingly, individuals who filed comments on the draft permit or participated in the public hearing may petition the U.S. Environmental Protection Agency (USEPA) to review the PSD provisions of the issued permit. In addition, as comments were submitted on the draft permit for the proposed project that requested a change in the draft permit, the issued permit does not become effective until after the period for filing of an appeal has passed. The procedures governing appeals are contained in the Code of Federal Regulations (CFR), "Appeal of RCRA, UIC and PSD permits," 40 CFR 124.19. If an appeal request will be submitted to USEPA by a means other than regular mail, refer to the Environmental Appeals Board website at www.epa.gov/eab/eabfaq.htm#3 for instructions. If an appeal request will be filed by regular mail, it should be sent on a timely basis to the following address:

U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001

Telephone: 202/233-0122

QUESTIONS AND COMMENTS WITH RESPONSES BY THE AGENCY

1. How does syngas differ from natural gas?

The syngas produced at the proposed plant will be a low-heat content gas, with only about 250 Btu/standard cubic foot, composed mostly of carbon monoxide and hydrogen. Natural gas is a high heat content fuel, with about 1,000 Btu/ standard cubic foot , composed mostly of methane. Raw natural gas and raw syngas are both processed to remove sulfur compounds and other contaminants before being sent for use as fuel.

2. Is it unusual for a power plant to store coal for 14 days?

It is not unusual for power plants to have coal stockpiles with at least a 14 day reserve

supply of fuel. This enables continued operation of a plant in the event of disruptions in the normal coal supply, as can potentially occur due to transportation disruptions, bad weather and labor strikes.

3. Will "manufactured gas plant waste" be deposited in the on-site landfill that would be developed as part of the proposed plant?

No, this landfill would not receive tars and liquid wastes of the type that contribute to contamination at sites of former manufactured gas plants. This landfill would be used for disposal of vitrified slag from the gasifiers. This is a solid, glass-like material that is formed when the molten slag from the bottom of the gasifiers cools and solidifies.

4. What toxic substances will be contained in the slag? Is there a Material Safety Data Sheet for the slag?

The toxic substances in the slag will be the heavy metals that are normally present in coal combustion waste, due to the trace level of metals such as arsenic, cadmium and beryllium in coal. Due to the vitreous nature of the slag, these materials should be bound up or contained within the slag with little potential for leaching. However, the leaching potential and waste characteristics of the slag will have to be tested when slag is initially produced, to confirm the practices that must be followed for the handling and disposal of the slag. Because this slag has not yet been produced and tested, there is not a Material Safety Data Sheet for this material.

5. How will the on-site landfill be designed? Will there be liners, monitoring, leachate management? Will there be an analysis of hydrology or aquifer effects? What will happen when the landfill closes?

The landfill must be designed and operated to comply with applicable requirements under 35 IAC Part 812, Subpart G, Chapter I, including requirements for liners, monitoring and leachate management. The particular requirements will depend on the characteristics of the slag from the plant that goes to the landfill. When the landfill is closed, relevant requirements for closure of landfills under 35 IAC Part 812, Subpart G will be applicable.

6. Long wall mining will harm agriculture.

Mining is subject to a separate regulatory and permitting program, which is specifically designed to prevent and mitigate detrimental environmental impacts from mining activity. This includes planning for ground subsidence, as is a particular concern for long wall mining, to prevent damage to structures, agricultural productivity and the natural environment. Concerns about the method of mining used at a new mine that might be developed to supply coal to the proposed plant are appropriately directed to the Illinois Department of Natural Resources. The comment is beyond the scope of this air pollution control permit, particularly as this permit addresses the emissions and air quality impacts of the proposed plant.

7. Who will be getting the coal mining jobs?

The proposed plant is being developed to use Illinois coal. However, Christian County Generation has not announced the selection of a particular source or sources of coal to supply the plant. Given the location of the plant in Central Illinois, there are a number of mines that could potentially supply coal to the plant. The company can be expected to pursue negotiations for the coal supply as the development of the plant progresses

8. This proposed plant is capable of making synthetic natural gas and clean diesel fuel at prices that are less than today's market prices. Because of this, it is very important for the economy of Illinois that this project go forward.

Christian County Generation has proposed a coal gasification plant that would only produce electricity. If Christian County Generation wants to alter the plant in the future to also produce synthetic natural gas, diesel fuel, or other products, it will have to apply for and obtain a new construction permit for the changes to the plant.

9. There are no customers yet for the electricity to be generated by the proposed plant.

While contracts for the electricity from the plant have not been finalized, Christian County Generation has stated that discussions are occurring with interested parties about power purchase agreements. As is often the case for new power plants, Christian County Generation expects that these contracts will be coordinated with the financing for the plant.

10. Christian County Generation should do something about carbon dioxide (CO_2) emissions, otherwise Christian County Generation will need to retrofit the plant in the future to reduce CO_2 emissions when regulations are adopted. Global warming should be addressed now.

One consequence of this plant using IGCC technology is that it will be "carbon capture ready." First, the technology to clean syngas for collection of CO_2 is existing technology, which is already in use when coal gasification is used to produce chemical feedstocks. Second, the retrofit costs for compliance with CO_2 regulations will be far less than if the plant were to use traditional boiler technology. This is because the gas cleanup system for IGCC technology is a "chemical process" that can be altered by the introduction of additional steps to facilitate capture of CO_2 from the raw syngas. These alterations will be facilitated with a plant layout that includes space between the different units in the gas cleanup train to accommodate additional steps. Finally, IGCC technology is amenable to CO_2 capture because the operating costs, principally for compression of CO_2, would be substantially less than with back-end CO_2 capture technology on a boiler.

11. A decision to grant this permit must consider global warming impacts. The international scientific consensus is that the earth's climate is changing and that human activity is a major factor. The International Panel on Climate Change report, *Climate Change 2007: The Physical Science Basis, Summary for Policy Makers*, notes that the global atmospheric concentration of carbon dioxide (CO_2) has increased, the atmospheric concentration of CO_2 in 2005 exceeded by far the natural range over the last 650,000 years as determined from

ice cores. The annual CO_2 concentration rate was larger during the ten years span of 1995-2005 than it had since the beginning of continuous direct atmospheric measurements (1960-2005). The Illinois EPA must do its part to prevent the dire health and environmental threats associated with global warming by prohibiting, or at a minimum mitigating, the 4,000,000 tons of CO_2 emissions that would potentially result from the proposed project annually.

Global warming is a world-wide phenomenon. The consensus of the scientific community is that global CO_2 emissions, currently estimated at over 20 billion tons annually, pose potentially adverse consequences on human health and the environment. The sheer enormity of the problem, however, is such that it will not be solved within the framework of existing laws and regulations.

In the United States, it is all but certain that the challenge of global warming will require a comprehensive regulatory approach, by Congress or a broad coalition of states, and the appropriate approach is presently the subject of political debate. The U.S. Supreme Court's decision in *Massachusetts et. al v. EPA* potentially signals the development of CO_2 regulations for automobiles and other mobile sources, while impending congressional hearings are likely to explore ways to regulate stationary sources, including power plants and other key sectors of our economy. Until such approaches are put into place by the appropriate legislative authorities, attempts to force controls or compel individual action on global warming through conventional environmental permitting programs are capricious and, even if implemented, would probably provide only illusory benefits. It might also have a stifling effect on the continuing development and deployment of IGCC technology.

In this case, the issued permit does not impose conditions relating to the control or reduction of CO_2 emissions. The commenter notes several aspects of the Illinois EPA's permitting decision that purportedly warrant the inclusion of some form of CO_2 emission control or permit limitation. Each of these issues is discussed separately below. In general, the comments do not support the imposition of CO_2 emission controls or limits. The Illinois EPA is not a legislative or quasi-legislative body. Rather, it is a creature of statute and the responsibilities for administering a permit program are tied to applicable rules and regulations. Ultimately, the decision for issuing a permit is based on a demonstration by the applicant that the project will comply with the applicable environmental standards and criteria. Moreover, permitting is not a substitute for rule-making. While the commenter's desire to compel action by the permit applicant and others is certainly understandable, the Illinois EPA is not in a position in this permit to dictate decisions about restraints on output, CO_2 offsets from other sources, or construction of co-located industrial facilities. The Illinois EPA also cannot dictate sequestration of CO_2, particularly when neither the technological nor policy challenges of sequestration have been resolved.

The applicant has proposed to build an electric power plant at a time when future energy demands are projected to outstrip current market supply. Recent developments with respect to certain coal-fired power plant proposals illustrate the many variables and risks that are associated with the current development of electrical generating plants, including the uncertain nature and demands of future regulations for emissions of CO_2. The

development of IGCC plants, however, is an important component of the technology that will be needed.

In contrast to existing coal-fired power plants using boiler technology, this proposed plant will be far better prepared for a CO_2 regulated future, in that it would be carbon capture ready. When CO_2 regulations are adopted, Christian County Generation will be able to add the necessary systems to capture and direct the CO_2 to sites for sequestration. At one point, the commenter discounts the significance of a project that is "capture ready," suggesting that it "does nothing to advance the critical question facing the entire coal industry – whether coal can have a future in a carbon-constrained world." This open-ended question is not one to be addressed by the Illinois EPA in its permitting decisions but, instead, should be left to industry and policy-makers.

It should also be noted that in the absence of this proposed project, electric power will continue to be supplied by other existing power plants in Illinois. The development of new power plants generally acts to improve upon, albeit incrementally, the manner in which electricity is produced as a whole. The more efficient and better-controlled process of producing electricity, as represented by this proposed IGCC plant, will act to reduce emissions of other less efficient power plants.

12. The Illinois EPA must consider global warming under the alternatives analysis required by the PSD program.[1] There are numerous alternatives to building a new coal-fired power plant. As the City of Springfield has demonstrated with its proposed Dallman Unit 4, it is possible to build new coal-fired generating units and through a combination of closing old, inefficient boilers, investments in wind power and energy efficiency, curb overall CO_2 emissions. If the Illinois EPA does decide to issue this permit, it should require Christian County Generation to curb overall CO_2 emissions associated with providing electricity to its customers by 25 percent below 2005 levels by 2012 (i.e., meet the Kyoto Protocol reductions.) This approach is consistent with the goal stated by Governor Blagojevich for his new Global Warming Task Force, i.e., identify strategies to curb global warming emissions to 1990 levels by 2020 and 60 percent by 2050.

There are numerous "options" for generating electricity that might conceivably be advanced in lieu of or in conjunction with a proposed new coal-fired generating unit. These options include the options undertaken by the City of Springfield for the project cited in the comment, i.e., shutting down older boilers (if one operates older boilers), purchase of wind power contracts, etc. Investments in wind, solar and other forms of alternative energy can be considered for any type of energy project, either as a stand-alone or as mitigation for the effects resulting from the implementation of the primary project(s). At present, such options are generally not compulsory or mandated by law. Rather, they represent discretionary business decisions by a project's developers and can reflect a multitude of considerations, including financial interests, risk avoidance, or socio-economic factors.

[1] Section 165(a)(2) of the Clean Air Act provides that a PSD permit may be issued only after an opportunity for a public hearing at which the public can appear and provide comment on the proposed source, including "alternatives thereto" and "other appropriate considerations."

In this instance, Christian County Generation has chosen to pursue construction of an IGCC plant, a developing technology that offers promising possibilities for greatly improved environmental performance, compared to existing boiler technology. The track record for IGCC plants is limited at this time, as there are only a handful of demonstration plants operating in the United States. While other new IGCC plants are proposed, it is evident that IGCC technology continues to pose a greater financial risk than conventional boiler power plant projects. Capital costs associated with IGCC have been estimated to be at least 20 percent higher than that of pulverized coal boilers. Operating costs are likely to be higher than conventional coal-fired power plants, in part, because of the standby gasification train that must be available in reserve during maintenance or outages. Christian County Generation's decision to confine the scope of its project to IGCC alone is perhaps attributed to any one of these risk-based factors. In any event, the nature and circumstances of the proposed project do not present valid reasons for the Illinois EPA to reject Christian County Generation's decision to only pursue development of an IGCC power plant.

The comment offers both the Kyoto agreement and the goals of the state's Global Warming Task Force as a basis for imposing controls or limits for CO_2 emissions from the proposed project. They actually do exactly the opposite. As previously mentioned, as a matter of policy, the Illinois EPA would prefer that limits on production outputs or global warming emissions be established by treaty, statute or regulation, rather than by ad-hoc permitting that is limited in its scope to new projects and is unable to reach or affect existing sources, which contribute the majority of emissions of concern.

13. CO_2 must be considered in the BACT collateral impacts analysis. Even in the absence of USEPA regulating CO_2, the Illinois EPA must still consider CO_2 as a non-regulated pollutant in the BACT analysis.

A determination of BACT must consider "collateral impacts," which is a term for the evaluation of energy, environmental and economic impacts included within the statutory definition of BACT and addressed in Step 4 of the Top-Down BACT process. In contrast to other parts of the BACT analysis, the consideration of collateral or secondary environmental impacts may appropriately consider non-regulated pollutants. As the USEPA's NSR Workshop Manual explains, this consideration may even extend to issues such as "noise levels, radiant heat, or dissipated static electrical energy, or greenhouse gas emissions." ***See, NSR Manual*** **at B.49.**

Generally speaking, the focus of this analysis is whether the selection of the most effective control alternative is appropriate given the projected collateral or secondary impacts for non-regulated pollutants. As the USEPA's Environmental Appeals Board has said, this focus is "couched in terms of discussing which available technology, among several, produces less adverse collateral effects, and, if it does, whether that justifies its utilization even if the technology is otherwise less stringent." Thus, if a given technology causes collateral impacts on non-regulated pollutants, such impacts may be relevant in selecting the technology best suited for the control of regulated pollutants. However, the collateral consideration of CO2 emissions does not lead to any changes to or adjustment of the BACT determination made for emissions of PSD pollutants from the proposed plant. Similar to

power plants using coal-fired boiler technology, the proposed plant will emit CO_2. However, there is no indication that conventional boiler power plants, including even the latest, high-efficiency boiler technologies, are better on a life-of-plant basis for control of CO_2 emissions. As previously mentioned, IGCC technology appears more advantageous than conventional boiler power plants in its potential for collection of CO_2 for sequestration. IGCC technology also has the potential to provide significant improvements in energy efficiency.

The consideration of CO_2 emissions in the collateral environmental impacts analysis does not provide leverage to impose requirements on this project related to CO_2 emission, such as out-put based limit based on a net thermal efficiency for the combustion turbines, as this commenter recommended in other comments. The commenter also argues that a cleaner feedstock should be required for the gasifiers as either a complete substitute for coal (i.e., natural gas) or as a blend (i.e., coal with biomass). The commenter relies upon the collateral impacts analysis as a basis to impose both requirements but stops short of identifying the impacts posed by IGCC technology. This erroneously attempts to introduce earlier steps of the Top-Down Process into the collateral impacts analysis.

14. The Illinois EPA may not allow an increase in emissions that cause global warming. The Illinois EPA is prohibited from granting this permit without mitigating the global warming impacts because it would allow the project component to emit CO_2 (and other greenhouse gases such as nitrous oxide) in such quantities that would cause or tend to cause air pollution… [both as that term is defined under the Illinois' Environmental Protection Act and as it is prohibited by 35 IAC 201.141].

Air pollution, as defined by Illinois' General Assembly in the Environmental Protection Act, is the "presence in the atmosphere of one or more contaminants in sufficient quantities and of such characteristics and duration as to be injurious to human health, plant, or animal life, to health, or to property, or to unreasonably interfere with the enjoyment of life or property." See, 415 ILCS 5/3.115(2004). As with nuisance law, the statutory definition contemplates an activity that creates such injury or unreasonable consequences that the law will presume damage and provide redress. Notably, the statute refers to the definition in the general air pollution prohibition that is found in Title II of the Act. See, 415 ILCS 5/9(a)(2004). The language of the definition of air pollution adopted by the Pollution Control Board's, which the commenter refers, is nearly identical.

The proposition argued in the comment is erroneous in several respects. First, the statutory framework for "air pollution," as cited by the commenter, is geared towards enforcement, not regulation. The language of both the statute and regulation is that of prohibition, whose redress would normally be found in an injunction or other equitable remedy before a court. It is not language that creates enabling authority through which the Illinois EPA could lawfully seek to "mitigate" or regulate the impacts of CO_2 emissions during permitting. Moreover, the concept of a statutory prohibition does not lend itself to partial restraints; the offending conduct is to be prohibited, not mitigated or sanctioned. Given the absence of proven technology to eliminate CO_2 emissions from fossil fuel combustion, it is not clear how the remaining amounts of CO_2 that the commenter would allow from the plant could be judged any less harmful or offending to society if, as alleged, CO_2 emissions are deemed a

form of "air pollution." Finally, to the extent that the commenter would have the Illinois EPA itself constrained through such a prohibition, the premise is likewise misplaced. State courts have rejected the notion that the Illinois EPA is subject to enforcement when acting in its established role as a permitting authority.

The argument advanced by the comment also fails to satisfy principles of "fundamental proof." A complainant seeking to enforce a right conferred by statute is generally required to prove both causation and injury. In the scientific community, as well as among public policy-makers, the notion of cause and effect is relative. However, in a courtroom, causation takes on a rigorous meaning, that is both highly demanding and structured. Generally speaking, factual causation is shown when a reasonable certainty exists that the alleged conduct caused an injury. Mere conjecture or speculation of causation is not enough. Similarly, the alleged injury must be amenable to proof, not merely contingent, remote or prospective. A speculative possibility of an injury does not satisfy this element. Given the difficulties in assessing the extent of global warming, not to mention assigning responsibility for harm to individual sources of CO_2 emission, the enforcement approach to regulating CO_2 emissions recommended by the commenter is clearly ill-advised.

Finally, treating CO_2 emissions as a regulated air pollutant under Illinois law would be wholly unconventional. CO_2 is a compound that is present in the earth's atmosphere, occurring both naturally and as a product of fossil fuel combustion. CO_2 in the atmosphere has not been commonly regarded as an air "pollutant." Indeed, the ecosphere depends upon the presence of CO_2 emissions to support green plants. Historically, CO_2 in the ambient atmosphere has not been considered harmful to humans or the environment. While the statutory definition of air pollutant is broad, citing to "any solid, liquid, or gaseous matter... or form of energy, from whatever source..." (415 ILCS 5/3.165 (2004)) and CO_2 would seem to fall within the meaning of the term, it should not be presumed that courts would reach the same conclusion. Courts are reluctant to construe language literally when it would defeat the purpose or intent of the law, leading to an outcome that was not contemplated by its drafters.[2]

15. A stringent output-based standard would minimize CO_2 emissions. To minimize the emissions of CO_2, the permit should require that the plant maintain a net thermal efficiency at or above 41 percent. This requirement would minimize both the emissions of regulated pollutants and the collateral emissions of CO_2.

This comment is not accompanied by any support to show that the recommended limit could be achieved by the proposed plant. Based on the application, the plant would be predicted to have a net thermal efficiency of about 37 percent. Given the developing nature of IGGC

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[2] Interestingly, Professor Currie, widely known as the principal draftsman of Illinois' Environmental Protection Act, expressed concerns about reading too much into certain elements of the definition of air pollution. In a 1976 law review article, Professor Currie remarked: "To seize upon broad definitional language of modest purpose to expand state regulation into areas not traditionally thought of as pollution smacks too much of invading the province of the legislature." See Enforcement Under the Illinois Pollution Law, Northwestern University Law Review, Vol. 70, No. 3 (July-August 1976).

technology it would be reasonable for the actual efficiency to be higher, but nothing would suggest that 41 percent efficiency is achievable. In addition, requiring this level of efficiency or any reasonable level of efficiency to be achieved by the proposed plant as initially constructed would be counterproductive for the future capture and sequestration of CO_2. This is because the efficiency requirement would not account for the substantial reduction in net output from the plant that would accompany future capture of CO_2 for sequestration, due to the energy that will be consumed by the equipment for capture and transfer of CO_2.

16. Why not consider alternatives as BACT? Did Christian County Generation consider wind?

Christian County Generation has indicated that it did not consider developing a wind-based power plant because it was interested in developing a base-load plant that would utilize Illinois' abundant coal resources. While it did consider building a coal-fired boiler power plant, it chose instead to pursue development of an IGCC plant.

A permit applicant is not legally obligated under the PSD program to identify or consider alternatives to a proposed major project. However, the public is afforded an unqualified right under the PSD program to comment on alternatives to a major project during the public hearing process for a project.

As this comment specifically inquires about use of wind energy as an alternative to the proposed project, the Illinois EPA recognizes the clear environmental benefits of wind energy, as it has zero emissions. As reported by the media over the last few years, companies that are interested in developing wind power projects are pursuing projects in the various areas of Illinois where the wind conditions are suitable for such projects. However, wind energy is not a substitute for traditional fossil-fuel-based power plants, like the proposed plant. As the strength of the wind varies, so does the power output from a wind-based power plant. On an annual basis, annual output of a wind based power plant in Illinois is only a fraction of its design capacity. Fuel-based plants, whose output is not dependent on the weather, are essential for a reliable supply of power.

17. How did the Illinois EPA determine that the proposed plant is needed, as was stated at the hearing?

The need for the proposed plant was assessed in very broad terms. The proposed plant is generally needed as it could enable existing plants, which are old and whose emissions are not as well controlled, to operate less or be shut down. This will reduce the loading of emissions to the atmosphere in Illinois and help to improve air quality. The plant is also desirable as it will assist in the development of IGCC technology. This cutting-edge technology, with potential advantages for capture and sequestration of CO_2 emissions, as well as improved control of regulated pollutants and improved energy efficiency, likely represents the next advance in technology for power plants using Illinois coal.[3] Given

[3] It is commonly recognized that coal and coal-fired power plants will continue to provide much of the electric power in the United States and the world. Accordingly, development of advanced coal technology, which includes carbon capture and sequestration, is essential to addressing the problem of climate change. While other technologies to more

Illinois' abundance of coal and the expected environmental benefits associated with IGCC technology, it is important that this technology be fostered so as to become commercially available to serve as one component in the collection of technologies that will maintain a supply of electricity to the residents of Illinois in the future.[4]

The plant is also desirable as it would provide economic benefits for the state of Illinois. It would represent new coal-fired generating capacity and would compete economically with existing power plants to supply power to the residents of Illinois, with resulting benefits for power customers. The plant would also use Illinois coal, which benefits both the men and women working in our state's coal mining industry and the economies of local communities.

18. Clean fuels can reduce the emissions of regulated pollutants and CO_2. Contrary to the language of the Clean Air Act, the Illinois EPA has not considered clean fuels in its BACT analysis. For some reason, the Illinois EPA sets two BACT limits for the combustion turbines, one for syngas and one for natural gas. If the turbines can burn natural gas then natural gas must be considered an available clean fuel in the top-down BACT analysis and may only be rejected in favor of syngas in accordance with the procedures detailed in the 1990 NSR Manual.

The combustion turbines are specifically designed to fire natural gas as a backup fuel, not as a primary fuel. The ability to use natural gas as a startup and standby fuel for the combustion turbines is entirely appropriate. Auxiliary fuels are routinely used at coal-fired power plants for startup of the boilers. IGCC technology currently poses concerns for the level of reliability of the supply of syngas, as this supply depends on the simultaneous operation of the separate gasification process. The ability to fire natural gas in the turbines if the gasification process is not in operation is a way to maintain electrical generation during such periods, even though at a significantly reduced rate.[5] For these reasons, the proposed project has been permitted to burn both natural gas and syngas in the combustion turbines. This also lead to the establishment of separate BACT limits for certain pollutants for the combustion turbines during the periods when they operate on natural gas.

At the core of the comment is the narrow issue of whether the Clean Air Act's PSD program compels a proposed major source to employ a certain type of clean fuel when its use would

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efficiently use coal are also being developed, IGCC technology appears to be the most promising technology at this time. Massachusetts Institute of Technology, The Future of Coal; An Interdisciplinary Study, March, 2007.

[4] The achievement of significant reductions in CO_2 emissions will require a portfolio of technologies for all sectors of the economy, as well as relevant policy and practices. This portfolio includes technology to substantially reduce the energy use and improve the energy efficiency of buildings, automobiles, trucks and other transportation equipment, and of all manner of stationary machinery. Also important is technology and infrastructure for use of renewable energy, including wind, biomass and biofuels. Advanced coal combustion technology with sequestration of CO_2 is another key component in the portfolio of technologies. Technology to convert coal to commercial fuels, accompanied by sequestration of CO_2 will also be important. Some of these technologies are available today; others need be developed so as to be cost-effective and be able to be widely deployed.

[5] The use of natural gas reduces the electrical output of the plant as electricity can only be generated by the input of natural gas to the CT. When syngas is produced, the gasification block also contributes to the electrical output of the plant. Much of the heat content of the hot syngas discharged from the gasifiers is recovered as steam in the radiant coolers, which steam is then also used in the steam turbine- to generate electricity.

redefine the fundamental purpose or design of the project. Since at least 1990, USEPA has refused to interpret the PSD program's BACT requirement as mandating that an applicant for a proposed coal-fired generating unit consider the use of natural gas, even though it is a cleaner-burning fossil fuel. In fact, USEPA has recently re-affirmed this approach, observing that "certain fuel choices are integral to the electric power generating station's basic design." The reasoning behind this long-standing policy is perhaps owing to the appreciation of the role that a PSD permit authority plays in the review process. While USEPA, including its delegated authorities, is obliged to "review" control options for proposed projects, it does not function as a central planning agency to plan, shape or design (or more aptly, redesign) the scope or objective of such projects.

A similar issue involving the use of low-sulfur coal is currently pending before a federal appeals court, which is reviewing an EPA administrative appeal that originated from a PSD-related permit decision by the Illinois EPA in 2005. The commenter, who represents the environmental advocacy group that initiated the appeal, has acknowledged that some types of control measures, including the use of clean fuels, need not always be required as BACT. Invoking an Environmental Appeals Board (EAB) ruling from 1989, the commenter observed that an applicant's fuel choices must be considered in the BACT evaluation unless it requires a change in the project's end-product. In that ruling, an applicant's decision to burn petroleum coke at a taconite ore plant did not give proper consideration to the optional use of natural gas, which the plant was already equipped to burn. The EAB reasoned that the source would continue to "manufacture the same product (i.e., taconite pellets) regardless of whether it burns natural gas or petroleum coke" and, further, observed that other taconite ore plants currently burned natural gas, either in whole or as a blend.

Here, the commenter effectively contends that the backup use of natural gas for the combustion turbines is a cleaner fuel than syngas and therefore must be addressed as a separate control option for the project in the BACT analysis. The argument fails to appreciate the integrated nature of the project. It also ignores the likelihood that the required use of natural gas in the combustion turbines would compromise the economic viability of the proposed plant. The proposed project, including its gasification trains, air separation unit and various parts of the syngas cleanup system, is specifically designed to gasify Illinois coal as its primary feedstock. If natural gas was mandated as a primary fuel for the turbines, a fundamental aspect of an IGCC plant, namely, the coal gasification systems would be effectively displaced. This would effectively redefine the proposed project.

The capital costs for the gasifiers, designed as they must be to reliably supply the entire generating capacity of the plant, represent a significant component of this project's total costs. If combined with the operating costs associated with natural gas power generation, the cost of the proposed project would be well beyond the range of costs currently projected for power plants using IGCC technology. Unlike the EAB case cited above, Christian County Generation would not have any reason to continue with its plans to manufacture syngas. In this regard, its economic analysis supporting the development of the proposed plant was founded on use of coal, like many new proposed power plants, with natural gas playing an incidental or secondary role as a auxiliary fuel, used only as needed to support the physical or financial operation of the plant.

IGCC technology offers a means to utilize one of Illinois' most abundant mineral resources to generate electricity, albeit with advantages over traditional methods due to improved environmental performance and potential improvements in efficiency. The pursuit of IGCC technology in Illinois is consistent with the General Assembly's enactment of various state laws and policies that fund research and promote the development and use of both coal and coal gasification. Mandating the use of any particular level of use of natural gas by the plant, beyond that needed for startup of the CTs, would act to thwart these worthy goals, as it would inappropriately constrain the proposed plant. It would also act to also deprive Illinois residents of an emerging technology at a time when increased diversity is being sought for the technologies that supply Illinois with electrical power.

19. Natural gas is a cleaner fuel than syngas and must be considered in the BACT determination for PSD pollutants, especially particulate. The draft permit would set PM limits for firing of natural gas in the CTs (0.007 lb/mmBtu for filterable PM and 0.011 lb mmBtu for total PM) that are lower than the limits for firing syngas. Therefore, the BACT analysis must consider the use of natural gas as an available clean fuel. Since the CTs are specifically designed to be able to fire natural gas, alone or in combination with syngas, there is no argument that burning gas would "redefine the source".

A requirement to use natural gas in the CTs when syngas is available would redefine the source. As a technical matter, the CTs are not designed to burn natural gas in combination with syngas. Rather the CTs are designed to allow operation on two separate fuels, either low-Btu syngas or high-Btu natural gas, in two separate modes of operation. Give the difference in the heat content of these two fuels, and the implications for the design of the respective burner systems, the CTs have combustion chambers that are specifically designed to burn each gas efficiently, by itself. The CTs cannot efficiently burn blends of these gases in any proportion.

If natural gas was the sole fuel to be combusted in the turbines, there would be no need whatsoever for the gasifiers, air separation unit, cleanup trains, etc. As discussed earlier, the purpose of the gasifiers and associated equipment is to convert coal into a clean syngas that may be combusted in the CTs. Requiring the use of natural gas in the turbines would necessitate the removal of the gasifiers and associated equipment from the project and would restructure the original project completely.

A requirement to use natural gas in the CTs is appropriately restricted to startup, when high-Btu natural gas is needed to allow stable ignition and ramp up of the turbine to operational conditions that allow syngas to be safely and efficiently fired.

20. The draft permit would not limit the use of natural gas as a fuel. BACT requires the consideration of natural gas as an available clean fuel control measure in the top-down BACT determination. Given that the plant can use natural gas exclusively – and BACT may require as much – the BACT determination for NOx must also include consideration of low-NOx combustion controls. In the project summary, the Illinois EPA rejects the use of low-NOx combustion controls on the basis that such controls are allegedly only

effective when burning natural gas and natural gas will only be used as a backup fuel. However, because the permit would not restrict the use of natural gas the Illinois EPA cannot simply allege that natural gas will be used as a backup fuel and fail to conduct a top-down BACT analysis that considers low-NOx combustion controls in combination with natural gas.

The use of natural gas as a possible fuel to be used exclusively in the combustion turbines was addressed above. Since the project relies on gasifiers that are specifically designed to its feedstock, exclusive use of natural gas in the process would render the complete integrated gasification process ill-conceived. The use of low-NOx combustion technology is not feasible as a control within the combustion turbines firing syngas because the nitrogen that was split off from the air separation unit would actually destabilize, rather than enhance, the combustion flame characteristics at the turbines.

21. Burning a mix of natural gas with syngas in the combustion turbines (CTs) would lower the emission for each regulated pollutant, including PM, so must be considered in the BACT analysis. If the cost effectiveness of combining gas, or a combination of gas and syngas, is within the range generally accepted as cost-effective for similar sources, the BACT limit for PM must be established based on a BACT analysis that factors in natural gas.

The cost-effectiveness of natural gas as a method to control emissions of the CTs is well above the level that is generally accepted as cost-effective for different pollutants, with a cost-effectiveness that is in excess of \$100,000/ton.[6] Moreover, while combusting a mixture of natural gas and syngas would theoretically reduce emissions of certain pollutants relative to the combustion of syngas alone, doing so is also not technically feasible. As already discussed, the CTs are designed for to burn two separate fuels, not a combination of fuels. Mixing of fuels would upset the flow of combustion air, disrupting combustion and the operation of the CTs.

22. The permit limits the syngas used in the combustion turbines (CTs) as fuel to syngas that has been processed by the syngas cleanup system. However, the only requirement for the sulfur content of the syngas is that it meet an SO_2 limit of 10 ppm by volume. There does not appear to be any clean fuel consideration applied to this standard. For example, as described above in comments with respect to PM BACT, there does not appear to have been any consideration of the use of natural gas either in whole or in part as a clean fuel control method to minimize the emissions of PSD pollutants, including SO_2. The SO_2 top-down BACT determination for the CTs must include consideration of natural gas. The use

[6] The cost-effectiveness of use of natural gas for control of PM, as compared to use of syngas, is readily estimated. Natural gas currently has a cost of about \$7.00 per mmBtu while coal costs about \$2.00 per mmBtu, resulting in a price differential of \$5 per mmBtu. The difference in the limit for total PM for the two fuels is 0.0110 lb/mmBtu (0.0220 – 0.0110 = 0.0110 lb/mmBtu). Based on this difference in limits, 180,818 million Btu of natural gas would have to be burned to reduce PM emissions by one ton. (2000 ÷ 0.011 = 181,818 million Btu). The differential in cost of fuel would be \$909,090 (\$5 x 181,818 = \$909,090). This is well beyond the value of cost-effectiveness that is considered reasonable for control of PM. If one combines the reduction for the different PSD pollutants calculated in this manner based on the difference in applicable limits, the cost-effectiveness of use of natural gas is approximately \$300,000 per ton.

of natural gas is consistent with Condition 4.2.2(a)(i) of the permit that lists natural gas as a control technology to limit emissions of SO_2 and PM.

As already explained, the mandatory use of natural gas to reduce SO2 emissions, while theoretically possible, would not be cost-effective. As related to syngas, the permit establishes a numerical BACT limit for the CTs for emissions of SO_2 that is expressed in terms of the sulfur content of the syngas, as this form of limit may be more readily measured than emission from the stack. This is also consistent with approaching the syngas as a "clean fuel" for purposes of SO_2 emissions, as well as PM emissions, which is how it is approached by the permit. In particular, as Condition 4.2.2(a)(i)) describes the selection of BACT control technology for emissions of SO_2 and PM from the CTs, it identifies use of either syngas that has been processed by the syngas cleanup system or natural gas.

23. There is no discussion of the feasibility of blending biomass into the feedstock for the gasifiers as a way to mitigate the emissions of regulated pollutants and "non-regulated pollutants," such as CO_2. Every increment of additional natural gas or biomass that displaces syngas means less regulated pollutant emissions associated with the burning of syngas and less CO_2 emissions. The Illinois EPA must require a top-down BACT analysis for each PSD pollutant that considers the use of biomass.

The use of biomass in the feedstock to the gasifiers would pose similar issues as use of low-sulfur Western coal, as was discussed by the Illinois EPA in the project summary accompanying the draft permit. Biomass would also pose additional issues that make this practice infeasible. 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.

As discussed in the project summary, the use of a low-Btu alternative feedstock for the gasifiers, like low-sulfur or biomass, 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 low-Btu feedstocks is not as efficient as gasification of high-Btu feedstocks, like Illinois coal. This effect significantly increases the predicted capital and operating costs for an IGCC plant that would use low-BTU feedstocks, as compared to the costs for a plant using high-Btu feedstocks. The work to date in the United States on IGCC technology has been concentrated on plants using high-Btu feedstock.

In addition, 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. While efforts are underway at this time to develop the supply of biomass nationally and to reduce its cost, by the US Department of Agriculture, the US Department of Energy and a variety of other agencies and organizations, biomass is not currently a commercial fuel, like coal.

This comment also assumes that the gasifiers would be adaptable to use of a feedstock

containing biomass. Gasifiers are designed for particular feedstocks, with the shape, interior refractory lining, cooling mechanism, etc., being a function of the properties of the design feedstock. The purpose of the gasifiers for the proposed plant is to specifically process the chosen feedstock, namely Illinois coal, so that they would not be designed for a biomass coal blend. Design of the gasifiers for a blended feedstock would only become practical if a reliable supply of the biomass material can be assured, which it cannot. In this regard, the Illinois EPA is not familiar with IGCC plants that operate on feedstock that are blended to include low-Btu materials. Experience suggest that the operation of a IGCC plant is made easier if high-Btu materials, such as petroleum coke, are blended with coal.

Finally, this comment incorrectly assumes that use of biomass would reduce emissions from the plant, as the level of sulfur and ash in the feedstock would be reduced. However, emissions of PM, SO_2 and sulfuric acid mist from the plant are determined by the effectiveness of the gas cleanup train, i.e., the level of contaminants that are allowed to remain in the gas stream leaving the cleanup train rather than by the quality of the feedstock. Indeed, as use of lower quality biomass feedstock would act to reduce the heat content of the syngas that is produced, it is reasonable to expect that it would be accompanied by an increase in NOx emissions.

While use of biomass in the gasifiers would reduce CO_2 emissions associated with use of fossil fuel, as biomass is a renewable fuel, it would not reduce absolute CO_2 emissions of the plant. Moreover, the global benefits from use of biomass fuels can be more readily achieved by use of such materials in generating units at other plants. In this regard, existing coal-fired boilers are much more amenable to blending of biomass into the coal supply and would benefit from reduced SO_2 emissions as SO_2 emissions are currently uncontrolled. Biomass would also be more effectively burned in new units that are specifically sized, designed and equipped for burning of biomass fuels.

24. An available clean feedstock that has received no discussion in the Illinois EPA's top-down BACT analysis is biomass. There are numerous examples of coal-fired power plants co-firing biomass that should be considered in the top-down BACT analysis. This is also consistent with the Governor's recent commitment to expanding the use of locally-grown bio-fuels.

Because the energy density of biomass, i.e., Btu per cubic foot, is much lower than that of coal, far more biomass would have to be transported from within a radius far from the plant to meet the equivalent energy needs that coal would provide for the plant. The costs of this would be uneconomical to the functioning of the plant. It is the economics of using coal as a feedstock that makes the plant economically viable.

25. The SO_2 top-down BACT determination for the CTs must include consideration of use of biomass as a feedstock in the gasifiers.

The circumstance of biomass with respect to emissions of SO_2 are similar to those with respect to PM emissions. The use of biomass as a feedstock is not a viable option that can be mandated as BACT for the plant, as previously explained.

26. The Illinois EPA rejected consideration of particulate controls for the CTs at the proposed plant, including electrostatic precipitation and filtration, on the grounds that their use in combination with pre-combustion controls would be "a theoretical approach to emission control that should not be attempted at the proposed plant." This is not a legitimate basis for rejecting post-combustion controls. Electrostatic precipitators (ESPs) and baghouses are widely used as post-combustion controls on coal-fired power plants. The Illinois EPA has not identified any technical reasons why such controls could not be used on an IGCC plant. The PM BACT analysis must be redone with, at a minimum, a consideration of ESPs and baghouses. The Illinois EPA may only reject post-combustion controls if it does so in accordance with a legitimate top-down BACT analysis.

Use of post-combustion control technology for PM emissions from the CTs was appropriately considered and rejected. Post-combustion controls are used on conventional coal-fired boiler power plants because "whole coal" is being burned and particulate emissions cannot be addressed prior to combustion. However, pre-combustion control of particulate is present at the proposed plant with the syngas cleanup trains. The Illinois EPA's statement, as quoted in this comment, reflects a technical assessment of the effectiveness of post-combustion control techniques for the CTs given that the fuel for the CTs is a cleaned processed gaseous fuel, not coal.

First, PM emissions of CTs are routinely addressed or controlled by the selection of fuel, i.e., natural gas and low-ash fuel oil are burned. Add-on post combustion controls are not used. These circumstances are also present for the CTs at the proposed plant, except that the gaseous fuel will be manufactured on-site from coal. Second, the particulate limits for the CTs are comparable to, if not significantly better than, the limits set for new coal-fired power plant boilers using post-combustion control technology. Given the stringency of the "process-based" limits for the CTs, it is not reasonable to expect that application of post-combustion control technology to the CTs would achieve any further reduction in PM emissions. The performance of particulate control devices on new coal-fired boilers is appropriately addressed in terms of the loss of particulate from the devices, not in terms of control efficiency. As the particulate limits or loss rates set for coal-fired boilers with post-combustion control devices are equal to or higher than the limits set for the CTs, the achievement of any further reduction in particulate emissions with post-combustion control is questionable. Moreover, the application of post-combustion control devices to CTs would present design and operational issues that are not present when applied to the exhaust from coal-fired boilers, starting from the much lower loading of particulate entering the control device. Lastly, a fundamental aspect of IGCC technology is pre-combustion control of the ash and sulfur contained in coal. This is because control of particulate and SO_2 emissions can be more readily and more effectively accomplished by processing the gaseous fuel stream to remove these contaminants prior to combustion, rather than after combustion, when these pollutants are present at much lower concentrations in the much larger volume of exhaust gas.

27. For the combustion turbines (CTs), the draft permit would set PM limits of 0.0090 and 0.022 lb/mmBtu, 3-hour block average, for filterable PM and total PM, respectively. This

filterable PM limit is identical to the filterable PM limit set in the PSD permit for East Kentucky Power Cooperative's Spurlock Unit 4, a new circulating fluidized bed (CFB) boiler. However, the proposed limit for total PM is higher than the limit set for Spurlock 4, 0.012 lb/mmBtu. The Illinois EPA indicates that the proposed PM limits for this project cannot be compared to the limits for coal-fired boilers, but does not explain why.

The limits for the CTs at the proposed plant should not be directly compared to limits for boilers because of the difference in what the heat input to the units represents, which is a consequence of the difference between boiler and gasification technology. For a boiler, the heat input from fuel to the generating unit and the boiler are identical, since there is only a single fuel combustion unit. For a CT at a coal gasification plant, the heat input to the CT is only part of the "heat input" to the generating unit, which is made up of both the gasifier and the CT. Some combustion of fuel or feedstock occurs in the gasfier to support the gasification process. The energy from this combustion is recovered as steam when the hot, raw syngas from the gasifier is cooled in the radiant cooler and this steam is then also used to generate electricity in a steam turbine at the plant. However, this energy or heat input is not counted in the heat input to the CT. At the proposed plant, it is expected that the heat input to the CTs will only be about 75 percent of the heat input to the gasifiers.

Accordingly, to make a proper comparison with the limits for a boiler, such as Spurlock Unit 4, the limits for the CTs at the proposed plant must be expressed on the same basis, i.e., the heat input into the power generation process. The adjusted limit for filterable PM for the CTs is approximately 0.0068 lb/mmBtu,[7] which is less than the limit for Spurlock Unit 4 cited in this comment, i.e., 0.009 lb/mmBtu. In fact, the filterable PM limit for Spurlock Unit 4 cited in the comment is based on a <u>30-day</u> rolling average. The limit for Spurlock Unit 4 on a 3-hour average is actually 0.015 lb/mmBtu. Accordingly, the limit for filterable PM for the CTs at the proposed plant is about half the limit for Spurlock Unit 4, when the limits are compared on an appropriate basis.

The adjusted limit for total PM from the CTs is approximately 0.0165 lb/mmBtu. This limit is lower than 0.018 lb/mmBtu, the lowest limit for total PM commonly set or accepted for new pulverized coal boiler generating units. While 0.0165 lb/mmBtu is higher than 0.012 lb/mmBtu, the limit for Spurlock Unit 4, this does not invalidate this limit for the CTs. The technical issue is the contribution of condensable PM to total PM emissions. Test data for emissions of total PM is available for a number of CFB boilers, including Spurlock Unit 3, that was apparently sufficient for the Kentucky Department of Environmental Protection to find that a limit of 0.012 lb/mmBtu would be achievable by Spurlock Unit 4.[8] A similar volume of test data is not available for IGCC plants, given that IGCC is a developing technology. There are also fundamental technical differences between CFB boilers equipped with selective non catalytic reduction (SNCR) for control of NOx, like Spurlock Unit 4, and combustion turbines burning syngas, with selective catalytic reduction (SCR) for control of NOx. These differences could lead to higher levels of condensable PM at the proposed plant,

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[7] The emission limit is adjusted by the ratio of the heat input to the CTs to the total heat input to the generating units (as would be measured at the gasifiers), i.e., 0.009 lb/mmBtu x 0.75 = 0.0068 lb/mmBtu

[8] In August 2004, USEPA, Region 2, set a limit for total PM for the CFB boilers at AES Puerto Rico at 0.03 lb/mmBtu, with a possibility for future revision to a limit as high as 0.05 lb/mmBtu.

as the levels of sulfuric acid mist and ammonium sulfate are higher with an SCR system. Thus, the limit for Spurlock Unit 4 does not provide the necessary safety factor that must be associated with a BACT emission limit. For PM, in particular, the emission limits set in permits for pulverized coal boilers, or even proposed for such boilers are more useful as they reflect units equipped with SCRs. Accordingly, a limit has been set for total PM from the CTs that is lower than the limit that is commonly required of new pulverized coal boilers, consistent with better performance of IGCC technology for PM, but that still has the necessary safety margin to be reliably achievable by the CTs.

28. Because USEPA has adopted performance specifications for continuous particulate matter emission monitoring systems (CEMS), such systems should be required on the CTs at the proposed plant.

Particulate matter CEMS are being developed for use at conventional coal-fired generating units and other emission units with the potential for substantial PM emissions. These circumstances are not posed by the gas fired CTs at the proposed plant, so it is doubtful that any meaningful information about PM emissions would be provided from PM CEMS systems. Certainly, as the performance specifications for PM CEMS are based on research conducted at units with significant potential for PM emissions, the existence of these specifications does not show that such systems would be effective on the CTs at the proposed plant. In addition, the performance specifications for PM CEMS that have been adopted by USEPA have not been developed for use on units like CTs.

29. The proposed NOx BACT limits (0.034 and 0.025 lb/mmBtu for syngas and natural gas, respectively), which are both on a 24-hour average, would not protect the national ambient air quality standards (NAAQS) and PSD increments. NOx is a precursor for ozone and the current ozone NAAQS is 0.08 ppm based on an 8-hour average. The permit does not explain how the proposed 24-hour NOx limits adequately ensure that the proposed plant does not cause a violation of the 8-hour ozone standard, as the permit is required to do.

The NOx limits in the draft permit are more than adequate to protect the NO_2 NAAQS and increments, which are both set on an annual basis.

The potential impact of the proposed plant on ozone air quality was addressed with a technique developed by USEPA for use during the processing of PSD applications. This screening technique was developed to predict maximum hourly concentrations of ozone, and currently serves as a surrogate for the ozone 8-hour NAAQS. There is no PSD increment standard for ozone. This technique was applied to the permitted emissions for NOx and VOM from the plant, even though the permitted VOM emissions of the plant are below the PSD significant emission rate of 40 tons/year. The predicted ozone concentration was 0.095 ppm, which is less than the 0.120 ppm, the one-hour NAAQS.[9]

[9] The maximum ozone impact predicted due to the plant's emissions was 0.008 ppm (part per million), one hour average. To determine if the NAAQS would be met, this impact was added to a background concentration representing current air quality in the area, 0.087 ppm. The resulting concentration, combining the plant's impact and value for current air quality in the area, is 0.095 ppm, which is less than 0.120 ppm, the one-hour ozone NAAQS. The background concentration was developed from data measured at the Illinois EPA ambient monitoring station in

30. The draft permit proposes a limit for sulfuric acid mist of 0.0035 lb/mmBtu, 3-hour average, for the CTs. This limit appears high given the SO_2 emission rate. In 2002, the AES Puerto Rico (AES-PR) permit for a coal-fired Circulating Fluidized Bed boiler plant has a sulfuric acid mist limit of 0.0024 lb/mmBtu.

The circumstances of the proposed plant and AES-PR are not comparable. Other important factors in the potential emissions of sulfuric acid mist from the CTs at the proposed plant, which are not considered in this comment, are the lower NOx emission limit and associated use of SCR. The NOx limit for the CTs is 0.034 lb/mmBtu, and must be achieved with use of SCR technology. The use of an SCR for NOx control is accompanied by catalytic conversion of a small amount of the SO_2 in the flue to SO_3 or sulfuric acid mist by the NOx reduction catalyst in the SCR. In contrast, the NOx limit for AES-PR is much higher, 0.10 lb/mmBtu, and AES-PR only uses SNCR technology. SNCR, which is not a catalytic process, is commonly used for control of NOx emissions from new CFB boilers, but is less effective and not able to achieve the NOx emissions rates of SCR technology.

The SO_2 emission limit for the CTs is also lower than that of AES-PR, 0.016 lb/mmBtu compared to 0.022 lb/mmBtu. While this will generally act to minimize the formation of sulfuric acid mist by the SCR, since less SO_2 is present, it cannot be assured that this will completely compensate for the effect of the SCR. Thus the limit set for AES-PR does not provide the necessary safety factor that must be associated with a BACT emission limit.

31. The Illinois EPA should consider a lower sulfuric acid mist limit and the use of a wet electrostatic precipitator (wet ESP) in a top-down BACT determination. The use of wet ESPs are now common on new coal plants burning high-sulfur coal. I am not aware of any obvious technical reasons why wet ESP could not be used on an IGCC plant as well.

Use of post-combustion wet ESP technology for sulfuric acid mist emissions from the CTs was appropriately considered and rejected. This technology is used on new pulverized coal-boiler power plants because "whole coal" is being burned and emissions of sulfuric acid mist cannot be addressed prior to combustion. However, pre-combustion control of sulfuric acid mist is present at the proposed plant as sulfur is collected in the syngas cleanup trains. This provides appropriate control for emissions of sulfuric acid mist, as well as SO_2, for the CTs.

The sulfuric acid mist limit for the CTs is comparable to the limits set for new pulverized coal power plant boilers using post-combustion control technology.[10] Given the stringency of the "process-based" limits for the CTs, it is not reasonable to expect that application of wet-ESP technology to the CTs would achieve significant, if any, further reduction in emissions. Wet ESP technology on coal-fired boilers works with levels of uncontrolled sulfuric acid mist emissions that are much higher than will be present in the exhaust from the CTs, to comply

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Springfield, the station nearest to the site of the proposed plant. This background value is the "design value" for the area, consistent with the format of the NAAQS, determined as the fourth highest hourly concentration measured in three years.

10 For example, the limit for sulfuric acid mist set for Spurlock Unit 4 is 0.005 lb/mmBtu, 3-hour average. The limits set for the Elm Road, Longview, Trimble County Unit 2 and Weston 4 range from 0.005 to 010 lb/mmBtu.

with limits that will be achieved by the CTs with pre-combustion process control. The application of a wet ESP to a CT would present design and operational issues that are not present when applied to the exhaust from a coal-fired boiler. The most obvious differences are the far lower concentration of sulfuric acid mist entering the device and the fact that SO_3 would enter as a gas, rather than in very fine droplets of water, because the wet ESP would not be preceded by a wet scrubber. Lastly, as previously discussed, a fundamental aspect of IGCC technology is pre-combustion control of the sulfur contained in coal, where it can be more readily and more effectively accomplished than by post-combustion control.

32. The draft permit would only limit opacity based on the NSPS, to no more than 20 %, except for one 6-minute per hour of not more than 27 %. This is not sufficient because it would not set a limit based on BACT-level control. For the CTs, the permit must contain a limit for visible emissions for regulated pollutants (e.g., PM and sulfuric acid mist) that is based on the maximum degree of reduction achievable with the best pollution control option for the plant. Although BACT limits for PM and sulfuric acid mist are typically set as emission rates (i.e., pounds per hour or pounds per million Btu hear input), a BACT limit must also "...include a visible emission standard...."

The permit explicitly sets BACT limits for PM and sulfuric acid mist, so as meet the requirements of the PSD program. The language in the regulatory definition of BACT at 40 CFR 52.21(b)(12) concerning limits for visible emissions, which is addressed by this comment, is contained in parentheses. Therefore, the question is whether this language, which is not present in the Clean Air Act, requires an opacity limit to be set as BACT <u>or</u> allows an opacity limit to be set as BACT. While opacity limits have been set as part of BACT for coal-fired boilers, this does not show that an opacity limit must be set in the present case. In addition, the emission units under consideration are combustion turbines, not boilers, so actions for boilers are also not dispositive of the matter. Since, the definition of BACT in the Clean Air Act does not include the parenthetical phrase in question and opacity is not a pollutant, there is not a statutory obligation to set an opacity limit. The enhancement to the regulatory definition of BACT by USEPA must be construed as a clarifying action on USEPA's part, confirming that it is acceptable for a permitting authority to set limits on visible emissions as BACT, even though it is not required. Incidentally, as this comment suggests that an opacity limit must be set for the CTs as related to emissions of sulfuric acid mist, as well as particulate matter, the basis of the comment is not immediately apparent.

Incidentally, the Illinois EPA does agree with this comment to the extent that as it indicates that the opacity limit set by the applicable NSPS does not reflect BACT. However, the identification of a particular level of opacity that correlates with compliance the PM emission limit is best done in conjunction with actual emission testing for PM.

33. Based on the results of testing of the circulating fluidized bed (CFB) boiler at Jacksonville Electric Authority's Northside plant, BACT for PM and sulfuric acid mist for the CTs should include an opacity limit of no more than 2 percent. In other words, if opacity at a CFB boiler can be limited to less than 2% opacity, Christian County Generation must explain why it cannot meet such a limit when firing syngas, a fuel with lower particulate

emissions than solid coal.

This comment does not provide sufficient technical basis to set a BACT limit for the CTs at the proposed plant, particularly as such a limit is not required, as discussed below. In particular, this comment does not provide the opacity limit set for this CFB boiler or include information on the range of observed opacity or the duration of opacity observations from the boiler. It also does not address the implications of differences between boilers and combustion turbines for the establishment of an opacity limit.

34. The draft permit does not appear to have any meaningful startup or shutdown limits for the CTs for any pollutants, except SO_2. Condition 4.2.2 of the draft permit exempts periods of startup and shutdown from any input-based limits for PM (both filterable and total), NOx, CO and sulfuric acid mist. The only other applicable limits to these pollutants appear to be the annual limits in Table 1 of Attachment 1. Annual limits are not sufficient to meet the requirement that a PSD permit include BACT startup and shutdown limits for each regulated pollutant and protect air quality standards. In setting startup and shutdown BACT limits, Illinois EPA must consider the use of cleaner fuels, i.e., other than syngas, such as natural gas and gasified biomass. If Illinois EPA issues a new permit with startup and shutdown BACT limits for each PSD pollutant – which it must – the Illinois EPA should explain why the public should not get an opportunity to comment on such new limits prior to being finalized.

The draft permit included short-term mass emission limits to address startup and shutdown of the combustion turbines and protect ambient air quality. These limits have been carried over to the issued permit. In addition to the work practices requirements in Condition 4.2.2(c) and (d), the draft permit included "secondary" BACT emission limits for periods of startup and shutdown.

Incidentally, in response to this comment, the Illinois EPA realized that necessary emission short-term emissions limits for the sulfur recovery unit had been inadvertently omitted from the permit. They are included in the issued permit, as necessary to protect air quality.

35. The term "startup" should be defined as "the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits." The term shutdown should be defined as the period beginning with the lowering of equipment from base load and lasting until fuel is no longer added to the combustion turbine and combustion has ceased.

In response to this comment, the meaning of the terms "startup" and "shutdown,"as well as the term "malfunction" have been clarified in the issued permit. The meanings of these terms are generally those under the federal National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, as specifically defined at 40 CFR 63.2. (See Condition 3.3(d).) The exception is particular conditions of the permit that address emission standards and other requirements under the federal New Source Performance Standards (NSPS), 40 CFR Part 60, for which the specific regulatory definitions of these terms at 40 CFR 60.2 would apply as a matter of regulation so as to be applicable.

It is appropriate to generally use the NESHAP definitions of these terms because the permit relies on certain provisions of the NESHAP to address proper operation of emission units, including requirements related to startup, shutdown and malfunction of emissions units. (See Condition 3.3.). While the NSPS and NESHAP definitions of these terms are similar, the definitions in the NESHAP are more recent and believed to better address the meaning of these terms. It is not appropriate for the permit to use the definitions of the terms "startup" and "shutdown" recommended in this comment. Those definitions would not serve to improve the common understanding of these terms. In particular, they would rely upon other terms that would still be undefined, such as "continuous operating level," "operating permit limits," and "base load." In addition, as the recommended definitions differ from the NESHAP definitions, they would likely interfere with the provisions of the NESHAP regulations, which have been borrowed from and included in the permit, functioning in a manner consistent with their role under the NESHAP.

The specific adoption of the NESHAP definition of the term "malfunction" does have consequences for certain conditions in the permit, as they were drafted relying upon a broader meaning of the term "malfunction." Certain provisions of the draft permit which required detailed recordkeeping and reporting for malfunctions were intended to require such actions for all malfunction-like events that resulted in or threatened non-compliance. To maintain this intent, these conditions now refer to "malfunction and breakdown," so that they provide for recordkeeping and reporting not only for "NESHAP-malfunctions" (i.e. sudden, infrequent and unavoidable failures of equipment), but also such events are predictable and avoidable. Similarly, for the provisions for the gasification trains where the term malfunction was used to distinguish different modes of operation, the terms malfunction and breakdown are used.

36. The draft permit would set a limit of 201 lbs of SO_2/hour for startup, shutdown and malfunction of the sulfur recovery unit. This is problematic because there are no obvious reasons why the permit could not require the use of natural gas during periods of startup and shutdown of the sulfur recovery unit and thereby avoid the firing of high sulfur syngas during these periods. In Condition 4.1.2.1(c)(iii), the draft permit does not require the use of natural gas during periods of gasifier startup. Accordingly, the use of natural gas must be considered in setting the SO_2 BACT limit for the sulfur recovery unit during periods of startup and shutdown. The proposed limit does not constitute BACT.

The sulfur recovery is a chemical process unit, not a combustion unit. It also does not "fire" high-sulfur raw syngas. As such, this comment is generally misdirected. More importantly, the sulfur recovery unit is a sophisticated, multi-stage apparatus to convert hydrogen sulfide (H_2S), which has been removed from the syngas by the Acid Gas Removal System, into sulfur (S). This occurs in two steps, first by partial oxidation and then by a catalytic reaction with SO_2 that is formed by complete combustion of some of the H_2S.[11] Given the complexity of the unit, with the various flows, pressures, temperatures and thermal balances that must

[11] The basic chemical reactions for the Claus sulfur recovery unit at the plant are:

Thermal Step:	$2H_2S + O_2 \rightarrow S_2 + 2H_2O$
Catalytic Step:	$4H_2S + 2SO_2 \rightarrow 3S_2 + 4H_2O$

be achieved for effective operation of the unit, the unit cannot operate as effectively during the transitory conditions of startup and shutdown as it can during normal operation. In other words, SO_2 emissions, which come out the "back" of the unit at the thermal oxidizer, are inherently higher during startup and shutdown than other times and must be addressed separately from normal operation. In addition, combustion of natural gas is not a feasible technique to reduce emissions during startup and shutdown and it would do nothing to help "prepare" the unit for actually processing H_2S. The unit must startup on the material that it will be processing.

37. The proposed BACT limit for malfunction of the sulfur recovery unit also is problematic because a PSD permit cannot set a limit for periods of malfunction. A source has an obligation at all times to minimize the time and degree of any malfunction. A permit cannot create a blanket amnesty for a certain degree and period of malfunction.

The permit includes numerical BACT limits that address all operation of the sulfur recovery unit, as necessary to require effective operation of the unit to minimize emissions and to protect air quality. However, like the BACT determinations for other units at the plant, the BACT determination for the sulfur recovery unit reflects a project-specific evaluation of the circumstances of the sulfur recovery unit at the proposed plant by the Illinois EPA. One key factor is that the plant will be using a developing technology, IGCC, which relies upon the coordinated or integrated operation of several distinct facilities, including the gasifiers, the the air separation plant, the CTs in the power block and the sulfur recovery unit. Another key factor is that IGCC technology would be implemented at a scale that is over twice the size of the largest demonstration project in the United States. Problems were experienced in the early years of operation of those demonstration projects. This poses obvious concerns for sudden upsets in the normal operation of facilities at the proposed plant that cannot reasonably be prevented, especially in the early years of operation. Finally, the permit establishes a stringent limit for normal operation of the sulfur recovery unit, which reflects requirements for sulfur recovery units at refineries at which the operational challenges posed by the proposed plant have long since been solved. These considerations dictate alternative numerical BACT limits for periods of malfunction, particularly as malfunctions would generally be defined in the issued permit using the rigorous definition in the NESHAP, 40 CFR Part 63.

The establishment of these alternative numerical BACT does not excuse Christian County Generation from the obligation to minimize emissions at all times. That obligation is specifically stated as an overarching requirement for the work practices that are also set as BACT. It is further developed by the requirement that the sulfur recovery unit be operated in accordance with written operating procedures that set forth the procedures that will be followed to minimize emissions. As adequacy of those procedures and the sources implementation of those procedures may be reviewed and, challenged, if they are lacking, these provisions of the permit should not be characterized as providing the source with amnesty.

38. The draft permit would not set BACT limits for each of the bulk handling facilities. The requirements for bulk handling provisions in the draft permit look nothing like the

requirements that were established for other proposed new coal-fired power plants, including the permits for Indeck, Prairie State and the City of Springfield. This section of the draft permit needs significant work, to identify each of the emission units (coal handling, coal storage, etc.) and establish through a top-down analysis appropriate BACT limits for each unit.

The permit sets BACT requirements for each category of bulk handling facility at the plant. In fact, these requirements are essentially identical to the requirements in the PSD permit issued to the City of Springfield for proposed Dallman Unit 4. The requirements are also similar to the provisions in the PSD permits for the other projects cited in this comment.

The BACT determination for bulk handling facilities is based on the BACT demonstration provided in the application, review of the BACT determinations made for material handling operations associated with other new coal-fired generating units, and the Illinois EPA's experience with material handling operations. The resulting BACT determination appropriately establishes BACT for the different categories of material handling operations. The BACT requirements for material handling include readily enforced performance standards as it is practical to do so, e.g., no visible emissions and use of appropriately designed filtration devices. For storage piles, for which such direct standards are not available, control measures must be used that achieve at least certain minimum levels of control efficiency, as demonstrated by standard engineering calculations developed by USEPA for assessment of the control of fugitive dust. The selected numerical values for nominal levels of control reflect emission data compiled by USEPA and the Illinois EPA's experience in addressing control of fugitive dust from storage piles. Given that there are various control systems and work practices that can be used to achieve this level of control, the permit provides flexibility in the measures that are used by the plant. These BACT requirements are accompanied by requirements for Performance Testing, Periodic Testing, Operational Instrumentation, Inspections, Recordkeeping, Notifications and Reporting as specified in Conditions 4.3.7-1 through 4.3.12, as well as certain specified Operating Requirements in Condition 4.3.5.

39. What about the reuse of wastewater in the cooling tower? Did the Illinois EPA consider what the effects of reused wastewater would be? The Illinois EPA should develop regulations to address wastewater reuse.

The Illinois EPA has not found any information that indicates that use of wastewater treatment plant effluent in the cooling tower at the proposed plant would have particular effects that are different than those that would be present with water from other sources if the water is appropriately treated for the presence of microorganisms. Accordingly, the issued permit includes requirements that address treatment of any wastewater treatment plant effluent that is used in the water supply for the cooling tower at the plant, as Christian County Generation has identified this as a possible source of water for the cooling tower. The conditions require that prior to use in the cooling tower, effluent undergo tertiary treatment by filtration and disinfection. This reflects the requirements of regulations adopted by the California Department of Health Service, CCR Title 22, Section 60306, which address treatment of wastewater treatment effluent that is used in cooling towers.

As a general matter, the use of wastewater treatment plant effluent in cooling towers, as well as for certain other purposes, is generally encouraged in California as a water conservation technique if the water has been appropriately treated for the particular use. In Illinois, as in California, appropriate use of wastewater treatment plant effluent is also to generally be accommodated or even encouraged as it conserves Illinois' water resources. As implied above, use of effluent may result in additional costs for pre-treatment for a particular use as compared to water from another source for which such pre-treatment is not needed.

40. The draft permit would require the cooling towers to have drift eliminators with a design rate of drift loss of no more than 0.0005 percent. This is not BACT and it is not an enforceable emissions limit. First, drift eliminator efficiency, by itself, does not correspond to a PM emission rate. Second, an emission rate, calculated from the drift fraction, TDS, and circulating water flow rate should be established as the permit limit for the cooling tower, based on a top-down BACT analysis. The draft permit sets a drift rate and requires that TDS be measured, but it falls short as it does not set an emission rate or maximum TDS level in the circulating water flow. Absent a limit on the dissolved solids in the circulating water, a drift efficiency rate does not limit total PM emissions. If cooling tower drift eliminators are relied upon as BACT, the permit must include a limit on the dissolved solids and circulating water flow based on the lowest concentration achievable.

The issued permit includes a BACT limit for the cooling towers expressed as an emission rate, in pounds of PM10 per hour, as requested by this comment.

41. Wet cooling tower technology is not the least polluting technology, and does not constitute BACT. Use of an air cooled condenser (ACC) or dry cooling, an alternative method, system or technique of cooling within the definition of BACT, is available and has lower PM emissions than a wet cooling tower. ACC have been used on large coal-fired power plants for over 25 years.

These comments do not provide an adequate basis to require ACC, or dry cooling, for the proposed plant. Dry cooling is a demonstrated technology. However, use of dry cooling in areas where water resources are limited and the relative humidity is low (e.g., weather conditions in which wet cooling would consume comparatively more water), does not demonstrate that dry cooling is appropriate for the proposed plant. This is because of the additional power required by dry cooling and its effect on the energy efficiency of the proposed plant, are overlooked by this comment. The additional 15 to 25 MW of power required for dry cooling would act to increase emissions of pollutants other than PM (as well as emissions of CO_2) to attain the same level of output from the plant. If dry cooling would lower the plant's efficiency by more than a few percent, the net effect of using dry cooling is a less effective technology as related to emissions because its use would act to increase overall emissions of PM, as well emissions of other pollutants from the plant.

42. The draft permit would not require any emissions testing for the cooling tower.

The cooling tower does not have a stack or vent that enables direct testing of particulate

matter emissions from the tower. Accordingly, emissions must be determined from relevant design and operating data using engineering calculations.

43. The permit must require monitoring of dissolved solids and an initial test and periodic testing of drift rates from the cooling towers.

A condition has been included in the issued permit requiring testing of the efficiency of the drift eliminators on the cooling tower, using Acceptance Test Code No. 140 (a test method of the Cooling Technology Institute). Requirements for periodic testing would be set as part of the future CAAPP operating permit for the plant. The condition in the draft permit that required regular sampling and analysis of the dissolved solids in the cooling water have been carried over in the issued permit.

44. The draft permit does not include BACT limits for emissions of $PM_{2.5}$. It does not appear that the Illinois EPA even considered a limit for $PM_{2.5}$. This must be corrected before a PSD permit can be issued. The PSD rules require a BACT limit "for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts." $PM_{2.5}$ is subject to regulation under the Act because the USEPA established a NAAQS for PM2.5 in 1997. $PM_{2.5}$ will be emitted from this plant in a "significant" amount because it will be emitted at "any emission rate." For these reasons, a BACT limit for is required.

In recent guidance related to implementation of PSD and NSR, USEPA has specifically confirmed that it is appropriate to use the emission rate for PM_{10} until an emission rate for PM expressed in terms of $PM_{2.5}$ is developed and adopted by USEPA. This guidance is wholly appropriate as emission test data is not yet available for PM2.5 emissions from emission units as needed to develop BACT limits expressed in terms of PM2.5. Indeed, USEPA has not yet promulgated a reference test method for emissions of PM2.5, and is still operating with a Condition Test Method. Finally, as appropriate for different emission units at the plant, the permit sets BACT for emissions of pollutants that are relevant to and serve as surrogates for direct emissions of PM2.5, including filterable PM, total PM and sulfuric acid mist. BACT is also set for emissions of SO_2 and NOx, which are precursors to the formation of PM2.5 in the atmosphere.

45. The limits for the combustion turbines (CTs) in the draft permit for the proposed plant are the same as those in the application the proposed Cash Creek IGCC plant Kentucky, except that the PM limits are slightly different. Why is that, given that they are identical projects?

The application for the proposed plant initially recommended limits for the CTs in terms of the fuel input to the gasifiers, e.g., a filterable PM limit of 0.0063 lb/mmBtu. In a revision to the application, revised limits were proposed that were that expressed in terms of the heat input to the CTs, e.g., a filterable PM limit of 0.0085 lb/mmBtu. To account for the precision of PM test methods, the limits in the draft permit reflect rounding to limits expressed in thousandths of a pound per million Btu, e.g., a filterable PM limit of 0.009 lb/mmBtu. The consideration of the PM test method was not made for Cash Creek, which results in a small difference in the limits for the two plants.

46. How much mercury will be emitted by the proposed plant?

The permit sets the permitted mercury emissions of the proposed plant about 135 pounds per year, which is the amount that it would be allowed to emit by the federal New Source Performance Standards (NSPS), 40 CFR 60.45Da. Under new state regulations for mercury emissions from coal-fired power plant, 35 IAC Part 225, Subpart B, which were adopted by Illinois' Pollution Control Board on December 21, 2006, the actual emissions of mercury from the plant will to be much lower, as will be readily achievable with carbon absorption in the gas cleanup trains. However, since these new regulations have two alternative emission standards and include provisions for a temporary technology-based standard for new units before the emission standards apply, the permitted emissions of mercury in the issued permit were still set based on the emission standard of the NSPS.

47. The permit for the proposed plant should address the applicability of Illinois' new landmark rules for emissions of mercury from coal-fired power plants.

The proposed plant must comply with all applicable requirements of 35 IAC Part 225, Subpart B, and the requirements of these regulations have been addressed in the issued permit. References to the various requirements of the these regulations, i.e., emission standards, emission monitoring, sampling of coal, recordkeeping/reporting, etc., have been included in Section 4.2 of the issued permit.

48. The draft permit would provide that if Christian County Generation does not commence construction within 18 months of the permit becoming effective, the Illinois EPA may extend the permit. The Illinois EPA should clarify that if Christian County Generation does not commence construction within 18 months that the permit is automatically void. The only exception would be if Christian County Generation submits a timely extension request to the Illinois EPA that includes an updated BACT and modeling analysis, further provided that there be an opportunity for public and USEPA review and comment prior to the Illinois EPA acting on the extension request. This is consistent with practice in other states.

This condition of the permit reflects applicable provisions of the PSD rules that address the validity of a PSD permit. As stated in at 40 CFR 52.21(r)(2) and repeated in Condition 3.2 of the permit, the permit will become invalid if construction is not commenced or completed in a timely matter, unless the permit is extended. However, as the PSD rules do not specify how an extension request is to be processed, it is not appropriate for the permit to specify how an extension request must be processed. While it is reasonable to expect that the processing of any extension request would normally include the elements suggested by this comment, it is also possible that circumstances could arise where other procedures might be applicable. For example, USEPA could amend the PSD rules to add additional elements to the PSD program, which would have to be addressed as part of processing of a request to extend a PSD permit.

49. The consultation required under the federal Endangered Species Act (ESA) must consider global warming impacts.

Consultation under the ESA has recently been concluded by USEPA. In a letter dated April 16. 2007, the United States Fish and Wildlife Service (USFWS) concurred with the USEPA that approval of the PSD permit will not likely adversely affect the federally listed species in the action area as defined in the biological evaluation. Federal PSD permitting actions, including those issued pursuant to a federally delegated program, are subject to ESA consultation requirements under federal law. However, the ultimate responsibility for complying with the requirements of the ESA rests with USEPA. Any comments on the appropriate scope of consultation or its findings should be directed to the USEPA or, alternatively, the USFWS.

50. Because ESA consultation is required as part of the processing of this application for the proposed plant, since a PSD permit is required, a permit should not be issued until consultation has been completed. The USEPA's Environmental Appeals Board (EAB) has warned that it expects that "ESA consultation would ordinarily be completed, at the very latest, prior to the issuance of the permit and, optimally, prior to the comment period on the permit, where the flexibility to address ESA concerns is the greatest." The EAB cautioned the Illinois EPA not to wait until after the permit is issued because it would "tolerate an ESA violation whenever an appeal is not taken." Despite this admonition from the EAB, the Illinois EPA is now proposing to issue a permit for the proposed plant without providing any of these procedural safeguards and without finalizing the ESA Consultation prior to the issuance of the draft permit. The Illinois EPA should allow the USEPA to finalize the ESA consultation process and provide an additional period for public review of the consultation findings before closing the comment period on this draft permit.

As stated above, consultation under the Endangered Species Act has been completed. The USFWS has concurred with the USEPA that approval of the PSD permit will not likely adversely affect the federally listed species in the action area as defined in the biological evaluation.[12]

51. The Illinois EPA should adopt a more holistic approach to permitting proposed coal-fired generating units. That is, the Illinois EPA should address all environmental permits at one time, rather than handling them separately, in a piecemeal fashion.

As a legal matter, federal and state regulations do not support combining the processing of the applications for different environmental permits as requested by this comment. Separate processes are established that allow appropriate review of the particular issues posed by each individual application. In addition, it is not practical to combine environmental permitting of proposed coal-fired generating units. This is because the planning and design of different aspects of a proposed unit proceed on separate schedules, so that permit applications are submitted in a staggered fashion. The application for air pollution control construction permit typically is first, as it is essential for the financing and further work on development of a proposed unit. Permit applications related to wastewater follow, particularly as the detailed design of wastewater treatment plant may be affected by decisions made in the air pollution control construction permit on Best Available Control

[12] Leter, April 16, 2007, Richard Nelson, USFWS, Rock Island Field Office, to Pamela Blakley, USEPA, Region 5.

Technology (BACT). An on-site landfill, if part of a proposed project, is designed last, as the nature of the landfill is determined by other aspects of plant design and off-site disposal of waste is available as an alternative to on-site disposal.

COMMENTS SUPPORTING THE PROPOSED PROJECT

52. I support the construction of the proposed plant because of the economic boost it would provide to Taylorville and Central Illinois in general project.

53. I support this project because it will help stabilize the cost of electrical power for the residents of Illinois, which is an important component of long-term energy policy.

54. It is important that the permit for the proposed plant be issued, because the construction and operation of the proposed plant will begin a process that will make existing coal-fired power plants obsolete, to be replaced with plants that will capture and sequester .their emissions of CO_2.

55. Clean coal technology, as presented with the proposed plant, is good for the environment, consumers and good for jobs. This is a win-win-win situation.

FOR ADDITIONAL INFORMATION

Questions about the public comment period and permit decision should be directed to:

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LISTING OF SIGNIFICANT CHANGES BETWEEN THE DRAFT AND ISSUED PERMITS

Condition 3.3(d): For the purpose of the permit, the meaning of the terms "startup", "shutdown", and "malfunction" have been clarified by reference to the definitions of these terms in the NESHAP, 40 CFR Part 63.

Condition 3.4(b): The provisions for ancillary emissions units have been expanded to generally address requirements of federal and state regulations that are applicable to these units.

Condition 4.1.2-2(b): Provisions addressing malfunction and breakdown of the sulfur recovery unit have been clarified, establishing a three-year period for SO_2 emission rates after the commencement of operation, and after which time this rate is no longer allowed.

Condition 4.1.6(b): Short-term emission limits for the sulfur recovery unit have been added.

Condition 4.2.2(c): The compliance time period for the sulfur content requirement for syngas combusted in the combustion turbines has been clarified, specifying a 3-hour average.

Conditions 4.2.3-2(c) and elsewhere: Provisions addressing Illinois' new regulations for mercury emissions from coal-fired power plants, 35 IAC Part 225 Subpart B have been added, to address the emission limitations and requirements for monitoring, coal sampling, recordkeeping, etc., under these regulations.

Condition 4.3.5(b)(ii): A condition has been added requiring storage piles to be addressed by the plant's fugitive dust control plan, along with roads.

Conditions 4.4.2(b): A BACT limit expressed as a PM_{10} emission rate, has been set for the cooling tower.

Condition 4.4.6: Revised PM_{10} emission limits are set for the cooling tower based on revised emissions calculations.

Condition 4.4.5(b): Requirements on the types of additives and use of plant generated wastewater were added.

Condition 4.4.5(d): A requirement that any wastewater treatment plant effluent used in the cooling tower to be first microfiltered and disinfected.

Condition 4.4.6: Emissions of PM_{10} from the cooling tower have been raised from 0.05 lb/hr to 1.44 lb/hr, and from 0.22 tons/year to 6.31 tons/year. This is to reflect a higher rate of emissions predicted by the Permittee based on revised design data.

Condition 4.4.7: For the cooling tower, a requirement has been added for testing of the efficiency of the drift eliminator.

Condition 4.4.9(c) and 4.4.10(b): Sampling and analysis records must be maintained as a result of the requirements set in (a) and (b) of Condition 4.4.9.

Condition 4.4.10(a)(iv): A requirement that PM_{10} emissions from the cooling tower be calculated has been added.

Tables I and III: The limits for filterable and total PM_{10} emissions from the cooling tower were increased, as discussed above. The limits for total PM_{10} from the combustion turbines were reduced to so that the permitted emissions of total PM10 do not change.