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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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.

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[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 ar 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]

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[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.

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF EAST KENTUCKY POWER COOPERATIVE, INC. HUGH L. SPURLOCK GENERATING STATION MAYSVILLE, KENTUCKY PETITION IV-2006-4 PERMIT NO. V-06-007 ISSUED BY THE KENTUCKY ENVIRONMENTAL PROTECTION CABINET DEPARTMENT FOR ENVIRONMENTAL PROTECTION, DIVISION FOR AIR QUALITY	ORDER RESPONDING TO PETITIONER'S REQUEST THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF STATE PERMIT

ORDER GRANTING IN PART AND DENYING IN PART
PETITION FOR OBJECTION TO PERMIT

On August 17, 2006, the United States Environmental Protection Agency (EPA) received a petition from the Sierra Club (Petitioner) pursuant to section 505(b)(2) of the Clean Air Act (CAA or the Act), 42 U.S.C. § 7661d(b)(2). Sierra Club's petition requests that the Administrator object to the permit issued by the Kentucky Division for Air Quality (KYDAQ or Kentucky) to East Kentucky Power Cooperative, Inc. (EKPC), for the operation of the Hugh L. Spurlock Generating Station (Spurlock Station) located in Maysville, Kentucky. The permit (No.V-06-007) is a state-issued operating permit for Units 1 through 4 at the Spurlock Station, with a combined Prevention of Significant Deterioration (PSD) construction air quality permit for Unit 4, and was issued by KDAQ pursuant to Kentucky Administrative Regulations (KAR) at 401 KAR 52:020 and 40 KAR. 51.017.

Sierra Club's petition raises several issues in requesting that EPA object to this permit. Petitioner alleges that: (1) the permit does not specify whether continuous opacity monitoring (COMS) data will be available to prove a violation of the opacity standard for Unit 1; (2) the permit must include a heat input limit under the heading *Operating Limits* for Unit 2; (3) the permit must contain a compliance schedule for bringing Unit 2 into compliance with PSD requirements; (4) the permit improperly omits an applicable requirement to construct and operate Unit 3 consistent with and according to the specifications provided in its permit application; (5) the permit contains erroneous best available control technology (BACT) limits at Unit 3 for several pollutants; (6) the permit contains

unenforceable limits related to particulate matter and hazardous air pollutant emissions from Unit 3; and (7) the permit contains erroneous BACT limits for Unit 4.

EPA has reviewed these allegations pursuant to the standard set forth in section 505(b)(2) of the Act, which requires the Administrator to issue an objection if the Petitioner demonstrates to the Administrator that the permit is not in compliance with the applicable requirements of the Act. *See also* 40 C.F.R. § 70.8(d); *Sierra Club v. Johnson,* 436 F.3d 1269, 1280 (11th Cir. 2006); and *New York Public Interest Group v. Whitman*, 321 F.3d 316, 333 n.11 (2nd Cir. 2002).

Based on a review of the information before me, including the petition; the facility's permit application dated January 20, 2006; the final effective permit issued on July 31, 2006; the administrative record supporting the permit; KYDAQ's Response to Comments dated June 1, 2006; and relevant statutory and regulatory authorities, I partially deny and partially grant Petitioner's request for the reasons set forth in this Order.

I. STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(1) of the Act, 42 U.S.C. § 7661a(d)(1), calls upon each state to develop and submit to EPA an operating permit program intended to meet the requirements of CAA title V. The Commonwealth of Kentucky originally submitted its title V program governing the issuance of operating permits in 1993. EPA granted interim approval to the program on November 14, 1995. *See* 60 Fed. Reg. 57186. Full approval was granted by EPA on October 31, 2001. *See* 66 Fed. Reg. 54953. The program is now incorporated into Kentucky's Administrative Regulations at 401 KAR 52:020. All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the Act, including the applicable implementation plan. *See* CAA § 502(a) and 504(a), 42 U.S.C. § 7661a(a) and 7661c(a).

The title V operating permit program does not generally impose new substantive air quality control requirements (which are referred to as "applicable requirements") but does require permits to contain monitoring, recordkeeping, reporting, and other conditions to assure compliance by sources with all applicable requirements. 40 C.F.R. § 70.1(b); *see also* 57 Fed. Reg. 32250, 32251 (July 21, 1992). One purpose of the title V program is to "enable the source, States, EPA, and the public to better understand the requirements to which the source is subject, and whether the source is meeting those requirements." *Id.* Thus, the title V operating permit program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units in a single document and that compliance with these requirements is assured.

A. Title V Review

Under section 505(a) of the Act and the relevant implementing regulations, *see* 42 U.S.C. § 7661d(a); 40 C.F.R. § 70.8(a), states are required to submit each proposed title V permit to EPA for review. Upon receipt of a proposed permit, EPA has 45 days to object to final issuance of the permit if it is determined not to be in compliance with applicable requirements or the requirements of title V. 40 C.F.R. § 70.8(c). If EPA does not object to a permit on its own initiative, section 505(b)(2) of the CAA provides that any person may petition the Administrator, within 60 days of the expiration of EPA's 45-day review period, to object to the permit. 42 U.S.C. § 7661d(b)(2); *see also* 40 C.F.R. § 70.8(d). In response to such a petition, the Act requires the Administrator to issue a permit objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act, including the requirements of 40 C.F.R. part 70 and the applicable state implementation plan (SIP). 42 U.S.C. § 7661d(b)(2); *see also*, 40 C.F.R. § 70.8(c)(1); *New York Public Interest Research Group (NYPIRG) v. Whitman,* 321 F.3rd 316, 333 n.11 (2nd Cir. 2003).

Petitions must be based on objections to the permit raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impracticable to raise such objections within that period or the grounds for such objections arose after that period. CAA § 7661d(b)(2); 40 C.F.R. § 70.8(c)(1). If the permitting authority has not yet issued the permit, it may not do so unless it revises the permit and issues it in accordance with section 505(c) of the Act, 42 U.S.C. § 7661d(c). However, a petition for review does not stay the effectiveness of the permit or its requirements if, as is the case here, the permitting authority issued the permit after the expiration of EPA's 45-day review period and before receipt of the petition for review. If, in responding to a petition, EPA objects to a permit that has already been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue the permit consistent with the procedures set forth in 40 C.F.R. §§ 70.7(g)(4) and (5)(i) - (ii), and 40 C.F.R. § 70.8(d).

B. Applicable PSD Requirement

For new major stationary sources,[1] applicable requirements include the requirement to obtain a preconstruction permit that complies with applicable new source review and PSD requirements. Part C of the CAA establishes the PSD program, the preconstruction review program that applies to areas of the country that have attained the National Ambient Air Quality Standards (NAAQS). CAA §§ 160–169, 42 U.S.C. §§ 7470-7479. In such areas, a major stationary source may not begin construction or undertake certain modifications without first obtaining a

[1] "Major stationary source" is defined, *inter alia,* as a fossil fuel-fired steam electric plant of more than 250 British thermal units (Btu) per hour heat input with the potential to emit 100 tons per year or more of certain criteria pollutants, such as nitrogen oxide (NO_x), sulfur dioxide (SO_2), or particulate matter (PM). 40 C.F.R. § 51.166(b)(1)(i)(a); and 401 KAR 51.001.

PSD permit. CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1). In broad overview, the PSD program includes two central requirements that must be satisfied before the permitting authority may issue a permit; the program (1) limits the impact of new or modified major stationary sources on ambient air quality and (2) requires the application of state-of-the-art pollution control technology, known as BACT. CAA §§ 165(a)(3) & (4), 42 U.S.C. §§ 7475(a)(3) and (4). The CAA further defines BACT as "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, *which the permitting authority, on a case-by-case basis*, taking into account energy, environmental, and economic impacts and other costs determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant." CAA § 169(3) (emphasis added); *see also* 401 KAR 51.001.

EPA has promulgated two largely identical sets of regulations to implement the PSD program. One set, at 40 CFR § 52.21, contains EPA's own federal PSD program, which was incorporated into the implementation plans of all states at the inception of the PSD program in the 1970s. EPA is the permitting authority in states operating under 40 CFR § 52.21 and permits issued under such programs are federal permits that may be appealed to EPA's Environmental Appeals Board, and ultimately, the federal courts of appeals. The other set of regulations contain requirements that state PSD programs must meet to be approved as part of a SIP. 40 CFR § 51.166. Over time, most states have received EPA approval for their PSD programs. In 1989, EPA approved Kentucky's PSD revision to its SIP as meeting these requirements in relevant part. 54 Fed. Reg. 36307 (September 1, 1989); *see also* 40 CFR § 52.931. For new major stationary sources in Kentucky and for major modifications of existing sources, the Commonwealth's regulations require sources to apply for a PSD permit at the same time that it applies for its title V operating permit. 401 KAR 52:020.

Where, as in this case, Petitioner's request that the Administrator object to the issuance of a title V permit is based in whole, or in part, on KYDAQ's alleged failure to comply with the requirements of the Commonwealth's approved PSD program in issuing a combined title V/PSD permit, the burden is on Petitioner to demonstrate that KYDAQ clearly erred by issuing the PSD permit with terms that are not in compliance with applicable PSD requirements.

As noted above, EPA has approved the PSD programs of most states, including the Commonwealth of Kentucky. As the permitting authority, such states have substantial discretion in issuing PSD permits. Given this, in reviewing a state's PSD permitting decision, EPA will not substitute its own judgment for that of the state. Rather, consistent with the decision in *Alaska Dep't of Envt'l Conservation v. EPA*, 540 U.S. 461 (2004), EPA's oversight role in the review of PSD permits in the context of a title V petition is limited to ensuring that the state

has adequately explained the basis for its determination and that the PSD permit comports with the requirements of the state's approved PSD program.

In determining the appropriate standard to apply to the PSD determinations in this case, the standard of review applied by the Environmental Appeals Board (EAB) in reviewing the appeals of federal PSD permits issued pursuant to the federal regulations at 40 CFR § 52.21, provides a useful analogy. Unlike title V objections, the appeal of federal PSD permits is governed by the regulations at 40 CFR § 124.19, and authority to review such permits rests exclusively with the EAB.[2] The standard of review applied by the EAB in its review of federal PSD permits has been explained in numerous orders of the EAB. *See* e.g., *Prairie State Generation Company,* PSD Appeal No. 05-05, slip op. (EAB, Aug. 24, 2006); *Kawaihae Cogeneration,* 7 E.A.D. 107, 114 (EAB 1997). In short, in such appeals, the burden is on a petitioner to demonstrate that review is warranted. Ordinarily, a PSD permit will not be reviewed by the EAB unless the decision of the permitting authority was based on either a clearly erroneous finding of fact or conclusion of law, or involves an important matter of policy or exercise of discretion that warrants review.

Thus, when a response to a petition to object to a title V permit requires the Administrator to determine whether an approved state's PSD permitting decision was adequately explained and meets the requirements of its SIP, EPA believes it is appropriate to apply a similar standard of review to that employed by the EAB in its review of federal PSD permits. When EPA promulgated the regulations governing the EAB's exercise of its review authority, the Agency noted that the power of review "should be only sparingly exercised." 45 Fed. Reg. 33290, 33412. Similar deference to the permitting authority is also justified in the case of a PSD permit issued by a state with an approved PSD program, as is the case here.

II. BACKGROUND

A. The Facility

The facility at issue - Spurlock Station - is an electric generating plant owned and operated by EKPC in Maysville, Mason County, Kentucky. The plant burns fossil fuels, primarily coal, to generate electricity. The plant includes two pulverized coal boilers and one circulating fluidized bed (CFB) boiler, with plans to construct an additional CFB boiler.

Emission Unit 1 is a 3500 mmBtu/hr dry-bottom wall fired boiler equipped with electrostatic precipitators (ESPs) and a low-NO_x burner, for which

[2]Because of the exclusive authority of the EAB in this area, the Administrator has declined to review the merits of a federal PSD permit in the context of a petition to review a title V permit. *See e.g., In re Kawaihae Cogeneration Project,* Petition No. 0001-01-C (March 10, 1997).

construction began before 1971. The precipitators were installed as part of the original plant construction but were rebuilt in 1990-1992. In addition, a selective catalytic reduction device was installed in 2003.

Emission Unit 2 is a 4850 mmBtu/hr tangentially fired boiler equipped with ESPs, low NO_x burners, and a flue gas desulfurization (FGD) system and was subject to review under 40 C.F.R. part 52.21, in November 1979. The FGD system has not been in operation since 1985. A selective catalytic reduction device was installed in 2003, after the date of the original title V permit issuance.

Emission Unit 3 was constructed in 2002. It is a 2,500 mmBtu/hr CFB boiler equipped with a baghouse filter, flash dry absorber and a selective non-catalytic reduction (SCNR) unit. This unit burns coal and tire derived fuel (TDF) with the condition that TDF will not be burned in excess of 10 percent of coal fuel by weight ratio.

Emission Unit 4 will be constructed at EKPC's existing Spurlock Station pursuant to issuance of the title V and combined PSD permit. Unit 4 is a new 300 megawatt coal-fired electric utility boiler, utilizing CFB technology. The new CFB boiler will be equipped with selective non-catalytic reduction, pulse jet fabric filters, dry scrubbing, and limestone injection pollution control systems. Unit 4 is virtually identical to the existing Unit 3, which also has a CFB boiler.

B. The Permit

The Spurlock Station title V permit at issue is a renewal permit. EKPC submitted an application for its initial operating permit in January 1976 to construct Unit 2. The initial operating permit issued by Kentucky was effective on November 10, 1982. The 1983 permit was subsequently amended on October 7, 1983. In 1996, EKPC submitted title V permit applications for its Dale and Spurlock units. On December 10, 1999, Kentucky issued a final title V permit for Spurlock Unit 2. On April 24, 2001, EKPC submitted a construction permit application for Spurlock Unit 3. The application was considered to be complete on February 8, 2002. The permit for Unit 3 became effective on June 21, 2002.

On June 8, 2004, KYDAQ received an application for renewal of the title V permit. This title V permit is combined with the proposed construction of Unit 4. EKPC submitted an air permit application dated September 13, 2004, seeking a permit to construct a new 300 megawatt net nominal generating unit. Kentucky's permit program provides for PSD permitting to occur concurrently with the title V permitting process. From December 2004 through January 2006, EKPC provided KYDAQ with additional information to support the combined title V and PSD permitting process. The application was administratively completed on January 20, 2006. Thereafter, KYDAQ proposed a draft title V permit and provided a public comment period, during which KYDAQ received timely comments, including those submitted by the Petitioner. EPA did not object to the proposed permit within its

45-day review period, which ended July 27, 2006. KYDAQ issued the final permit on July 31, 2006, which included the renewals of the existing title V permit for Units 1 though 3 and the initial combined title V and PSD permit for Unit 4.

C. Litigation History

On January 24, 2003, EPA issued an Notice of Violation (NOV) to EKPC for PSD violations at the Spurlock Station concerning Unit 2. Subsequently on January 29, 2004, EPA filed an enforcement action in federal district court against EKPC alleging similar PSD violations at Unit 2. *U.S. v. East Kentucky Power Cooperative, Inc.*, Case No. 04-34-KSF (E.D. KY).[3] While the parties have entered into a proposed consent decree to resolve the enforcement proceeding, it has not yet been finalized by the court.

In addition, Petitioner brought a state administrative challenge of this title V permit pursuant to the Kentucky Revised Statute (KRS) 224.10-440. A formal administrative hearing on that challenge was held on December 4, 2006. At the conclusion of the oral arguments, the case was submitted to the Secretary of the Kentucky Environmental and Public Protection Cabinet (Secretary) for issuance of the final Order. The Hearing Officer's Report and Recommended Secretary's Order was filed on April 16, 2007. The Secretary has until September 12, 2007, to file a final Order in the administrative proceeding.[4]

Finally, on September 28, 2006, Petitioner filed a deadline suit to compel the Administrator to respond to the title V petition at issue in this Order. *Sierra Club v.*

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[3] The United States alleged, *inter alia*, that EKPC performed "major modifications" at the Spurlock and Dale Plants, within the meaning of the regulations implementing the PSD program, in connection with a series of capital projects and operational changes at the Spurlock Plant to supply steam to the Inland Container Corporation, and a series of capital projects at the Dale Plant involving the replacement of boiler and turbine components. At Spurlock Unit 2 and Dale Units 3 and 4, the United States alleged that these projects resulted in unpermitted "significant net emission increases" of NO_x, SO_2 and/or PM under the PSD program. The United States asked that the Court order EKPC, *inter alia*, to remedy the alleged violations by requiring installation of the best available control technology on Spurlock Unit 2 and Dale Units 3 and 4, in order to control and reduce emissions of NO_x, SO_2 and/or PM. The United States also alleged that the projects undertaken at Dale Units 3 and 4 violated the applicable New Source Performance Standards for these pollutants, and that EKPC failed to include PSD and NSPS requirements triggered by its projects in its operating permits required by title V of the CAA. On July 2, 2007, the United States and EKPC lodged a proposed Consent Decree in the U.S. District Court for the Eastern District of Kentucky. Judicial approval of the settlement is pending court review.

[4] The issues presented at the hearing include the following allegations:(a) that the Cabinet failed to make certain information available to the public during the public comment period; and (b) that the Cabinet erred in determining the BACT selection for NO_x for Unit 4.

Johnson, No 1:07CV00414 (RWR) (D.D.C). On July 18, 2007, notice of the proposed consent decree to address this deadline lawsuit was published. 72 Fed. Reg. 9413. Pursuant to the terms of the proposed consent decree, EPA has until August 31, 2007, to respond to the petition.

III. THRESHOLD REQUIREMENTS

A. Timeliness of Petition

Section 505(b)(2) of the Act provides that a person may petition the Administrator of EPA, within sixty days after the expiration of EPA's 45-day review period, to object to the issuance of a proposed permit. As noted above, EPA's 45-day review period for the Spurlock Station title V permit expired on July 27, 2006. Thus, the sixty-day petition period ended on September 27, 2006. EPA received the subject petition on August 17, 2006. Accordingly, EPA finds that Petitioner timely filed its petition.

B. Objections Raised with Reasonable Specificity During Public Comment Period

The Petitioner filed this petition pursuant to CAA § 505(b)(2), under which the Administrator will object to a permit if "the petitioner demonstrates to the Administrator that the permit is not in compliance with the requirements of this Act, including the requirements of the applicable implementation plan." EPA considers whether the Petitioner has provided sufficient information to make the requisite "demonstrat[ion]" under the facts, circumstances, and legal issues of the particular case, viewed in light of the provisions, structure of title V and the relationship of those provisions with the enforcement provisions of title I. *See In the Matter of Georgia Power Bowen Steam –Electric Generating Plant, et al Final Order*, dated January 8, 2007. Section 505(b)(2) of the Act also provides that a petition shall be based on objections raised with reasonable specificity during the public comment period provided by the permitting agency. EPA reviewed the comments submitted to Kentucky during the public comment period for the Spurlock Station title V permit and found that the comments provide a sufficient basis for the petition – the objections raised in the petition were timely raised, with reasonable specificity, in Petitioner's written comments. Therefore, Petitioner has satisfied this statutory requirement.

IV. ISSUES RAISED BY THE PETITIONER

A. Use of Credible Evidence

Petitioner's Comment: Petitioner points to the permit's specific monitoring requirements for Unit 1 and asserts that Section B.4.a. could be read to limit the credible evidence that may be used to establish an opacity violation. Petitioner states that when the continuous opacity monitoring system (COMS) indicates an

exceedance of the opacity standard, the permit requires the source to either conduct a Method 9 test or accept the COMS readout, but asserts that this provision is not a limit on the type of evidence that can be used to enforce the underlying opacity limit. Petitioner asks the Administrator to object to the permit because it may create confusion on this point.

EPA's Response: EPA interprets the title V permit to allow EPA, KYDAQ, citizens and EKPC to use any credible evidence to determine compliance with and/or enforce an applicable requirement of the permit. This interpretation is grounded in both the CAA's statutory and regulatory enforcement provisions, as well as the provisions of the title V permit itself.

The Act provides EPA, KYDAQ and citizens with authority to bring enforcement actions against a source for violation of any requirement or prohibition of an applicable implementation plan or permit, including a title V permit. 42 U.S.C. §§ 7413(a), 7604(a)(1), 7604(f)(4). Section 113(a) of the CAA provides that EPA may bring an enforcement action based on "any information." 42 U.S.C. § 7413(a). In response to a 1984 district court ruling that limited the evidence EPA could use to prove a violation of an emission standard or limitation, Congress amended Section 113(e) of the CAA in 1990, to clarify that "any credible evidence" could be used for compliance and enforcement purposes. 42 U.S.C. § 7413(e).

EPA promulgated the Credible Evidence Rule (CER) following the 1990 CAA Amendments, to further clarify that any credible evidence could be used for compliance with the new title V permit program, as well as other compliance and enforcement efforts. 62 Fed. Reg. 8314 (February 24, 1997). As stated in the preamble, the CER "merely removes what some have construed to be a regulatory bar to the admission of non-reference test data to prove a violation of an emission standard, no matter how credible and probative those data are that a violation has occurred." 62 Fed.Reg. at 8315. Specifically, the CER was "designed to clarify that non-reference test data can be used in enforcement actions, and to remove any potential ambiguity regarding this data's use for compliance certifications under Section 114 and title V of the [CAA]." 62 Fed.Reg. at 8314. Further, to clarify the ability of citizens to use any credible evidence (such as in an action under section 304 of the CAA), EPA noted in the CER that "today's rule creates no new rights or powers for citizen enforcers; instead, the rule clarifies existing EPA regulations. Citizens have been free to use credible evidence in [CAA] enforcement and have prevailed in at least two court cases using it." 62 Fed. Reg. at 8318. *See e.g.*, *Sierra Club v. Public Service Company of Colorado, Inc.*, 894 F. Supp. 1455 (D. Colo. 1995); *Unitek Environmental Services, Inc. v. Hawaiian Cement*, 1997 U.S. Dist. LEXIS 19261 (D. HI 1997); *but see*, *Sierra Club v. TVA*, 430 F.3d 1337 (11th Cir. 2005) (prohibiting a citizen from admitting evidence because Alabama had not adopted the CER into its SIP).

The CER also included changes to federal regulations, notably, 40 C.F.R. § 60.11(g), related to New Source Performance Standards. That regulation specifically provides:

> For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

40 C.F.R. § 60.11(g).

Further, EPA interprets Kentucky's State implementation Plan, consistent with the 1997 CER, specifically 40 C.F.R. § 51.212(c), as not precluding any entity, including EPA, citizens, or the state, from using any credible evidence to enforce emission standards, limitations, conditions or any other provision of the Kentucky SIP.[5] *See* Letter from Stephen L. Johnson, EPA Administrator, to Robert Ukeiley, June 29, 2007 (Response to Petition for Rulemaking on Credible Evidence Revisions in Kentucky).

Finally, the title V permit here does not preclude the use of any credible evidence in determining compliance with applicable requirements. There is no language in the permit which Petitioner can identify that implies or affirmatively disallows the use of any credible evidence. Furthermore, the absence of language regarding the use of credible evidence in the title V permit does not preclude its use in demonstrating compliance. *See e.g., In the Matter of Motiva Enterprises Final Order*, Petition Number: II-2001-05, dated September 24, 2004; and *In the Matter of Starrett City Final Order*, Petition Number: II-2001-01, dated December 16, 2002. The Spurlock Station permit does not state that Method 9 is the sole or exclusive method used to determine compliance. The permit refers to Method 9 test as the reference test method provided in the SIP for the purpose of determining compliance with the opacity limit. However, as EPA explained in adopting the

[5] The Kentucky SIP also includes language indicating that Kentucky can use "any information" to enforce its SIP. *See, e.g.*, 40 KAR 50:055 (concerning compliance); and 401 KAR 50:060 (concerning enforcement). These two provisions were incorporated into the Kentucky SIP on May 4, 1989 (54 *Fed. Reg.* 19169) and July 12, 1982 (47 Fed. Reg. 30059), respectively. Further, Kentucky's regulations include the incorporation by reference of 40 C.F.R. §§ 60.11 and 61.12 in 401 KAR 60:005, Section 2(1); and 401 KAR 57:002, Section 2(1), respectively. These provisions are not contained in the Kentucky SIP because regulations pertaining to new source performance standards and hazardous air pollutants are not included as part of the SIP for any state.

CER, this means that reference tests, such as a Method 9 test in this case, performed under EPA and State regulations are the benchmark against which to compare other emissions data or parametric data, or engineering analyses, regarding source compliance. *See* 62 Fed. Reg. 8314. Regardless of whether the source chooses to conduct a Method 9 test, the permit requires the source to maintain records of all COMS data which ensures the availability of this data in an enforcement action. In short, nothing in the permit limits EPA, KYDAQ, or citizens from using credible evidence to bring an enforcement action for opacity violations consistent with EPA's 1997 Credible Evidence Rule and Kentucky's SIP.

While the permit allows EKPC to conduct a Method 9 test as a response to an exceedance of the opacity standard, as measured by COMs, EKPC could conduct such a test irrespective of whether the permit specifically allowed it as a response to the opacity exceedance. The permit's provision for a Method 9 test does not change the fact that the COM may measure an exceedance and does not affect the right of EPA, Kentucky or citizen to bring an enforcement action to remedy the exceedance. In short, EPA does not believe this permit provision has any effect on the scope of the evidence that can be utilized in enforcement action, given that Petitioner has not demonstrated that the permit is inconsistent with the Act. EPA denies the petition with respect to this issue.

B. Unit 2 Operating Limits

Petitioner's Comment: Petitioner asserts that the permit appears to require no operating limits for Unit 2 when this Unit should be subject to operating limits carried over from the underlying state issued operating permit. Petitioner points out that the 1976 construction permit application submitted for Unit 2 represented that EKPC would construct and operate a pulverized coal unit with a maximum heat input of 4,850 million British thermal units per hour (mmBtu/hr). Further, this maximum heat input appears in the 1982 and 1983 state issued operating permits covering Unit 2. Petitioner also points out that EPA issued an NOV and filed an enforcement suit against EKPC for violating the 4,850 mmBtu/hr heat input limit (referenced in footnote 1, above). Petitioner asks the Administrator to object to the title V permit because it lacks an enforceable heat input limit.

EPA's Response: Petitioner's primary argument is that the title V permit states "none" under the permit category "Operating Limits" for Unit 2. Petitioner argues that the title V permit, therefore, does not contain an enforceable operating limit. EPA recognizes that there is no maximum heat input limit stated under "Operating Limits" in the title V permit. EPA also notes that the title V permit specifically states in Section G.15, that the title V permit subsumes and incorporates all of the applicable requirements from the existing operating permit. EPA believes this would include the maximum heat input from the underlying state operating permit (SOP).

However, on March 30, 2007, as part of the ongoing EPA enforcement action described above, the United States District Court for the Eastern District of Kentucky ruled that the heat input limit in the underlying SOP ceased to be enforceable upon issuance of EKPC's 1999 title V permit. Specifically, the court stated: "[T]o the extent any term condition, or description in the 1983 SOP was modified by the title V permit or is inconsistent with the title V permit, the later-issued title V permit must control. The Court finds that the reference to the '4850 mmBtu/hr' in the title V permit is just such a term." *United States v. East Kentucky Power Cooperative*, slip op. at 21. The court noted that KYDAQ listed Spurlock Unit 2's maximum heat input as a "description" in the title V permit rather than as a federally enforceable "Operating Limitation." Slip op. at 20-25. The court further ruled that the "description" identifying the "maximum continuous rating" of 4,850 mmBtu/hr listed for Spurlock Unit 2 in the 1999 title V permit was not an enforceable limitation as it appeared in that permit. *Id.* The title V permit that is the subject of this petition contains language similar to the 1999 title V permit. Therefore, according to the ruling of the court, the title V permit does not contain the maximum heat input limit contained in the underlying SOP.

In addition, the use of the term "modified" in the language cited above cannot be read to mean that the heat input limit in the 1983 SOP was not an "applicable requirement" within the meaning of 40 C.F.R. § 70.2, or that the title V permit eliminated the heat input requirement from the 1983 SOP. The title V program does not impose new applicable requirements nor is the title V permitting process the appropriate mechanism for changing or modifying applicable requirements found in underlying permits. Instead, the underlying permit in which the applicable requirement is found must be modified, and then incorporated into the title V permit as an applicable requirement.[6] Thus, the placement of the maximum heat input in the description section of EKPC's 1999 title V permit could not have eliminated the heat input limit as an applicable requirement of the underlying 1983 SOP.

Based on the foregoing, EPA finds that the title V permit is deficient for its failure to include as an applicable requirement the maximum heat input limit found in the underlying 1983 SOP. Therefore, I grant the petition on this issue and direct KYDAQ to amend the permit and to include the applicable heat input limit for Unit 2 under the "Operating Limits" category of the permit.[7]

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[6] To the extent that a state with a merged title V/PSD permitting program (such as Kentucky's) seeks to change applicable requirements in an underlying permit, such changes must be clearly delineated as being made outside of the title V part of the process and the rationale for the change must be clearly stated.

[7] It is apparent the EKPC was aware that the heat input limit was an enforceable limitation in that it previously requested that KYDAQ revise the maximum heat rate for Unit 2 from 4,850 million mmBtu/hr to 5,3555 mmBtu/hr. KYDAQ denied EKPC's request when they informed EKPC that a PSD permit was required for such modification.

EPA wishes to emphasize that its decision to grant Petitioner's request on this issue does not conflict with the proposed consent decree that will resolve EPA's civil enforcement action for EKPC's alleged violations of the maximum heat input limit contained its underlying state operating permit, filed on January 29, 2004. Paragraph 165 of the proposed consent decree requires EKPC to apply for an amendment to its title V permit for the Spurlock Plant that incorporates a maximum continuous rating (MCR) of 5,600 mmBtu/hour. The proposed consent decree does not provide that this MCR replaces the 4,850 mmBtu/hour heat input limit found in its underlying 1983 SOP, nor does it otherwise alter the maximum heat input limit contained in the underlying 1983 SOP.

Further, although the proposed consent decree in paragraph 119 releases EKPC from claims arising from the alleged violations of Parts C and D of the Act, failure to obtain an operating permit that incorporates applicable requirements under the Kentucky SIP, and operation of Spurlock Unit 2 above a maximum heat input of 4,850 mmBtu/hr, the proposed consent decree does not relieve KYDAQ of its obligation under Section 504, 42 U.S.C. § 7661c, and 401 KAR 52.020, to ensure that the Spurlock Unit 2 title V permit contain all applicable requirements under the Act. This includes the maximum heat input limit contained in EKPC's 1983 SOP. Therefore, KYDAQ must amend EKPC's title V permit to incorporate the maximum heat input limit from the underlying state permit or EKPC must apply to KYDAQ under the Kentucky SIP for a permit that would authorize a change in that heat input limit, which in turn would be incorporated in the title V permit.

C. New Source Review (NSR) Compliance Schedule for Unit 2

Petitioner's Comment: Petitioner asserts that the EKPC permit is not in compliance with the CAA because it does not assure that Unit 2 is in compliance with applicable PSD requirements and does not include a compliance schedule to bring the Spurlock Station into compliance with applicable PSD requirements, which are found in the Act and Kentucky's SIP. Petitioner points out that EPA issued an NOV to EKPC for alleged PSD violations at Unit 2 and also filed a complaint in federal district court alleging similar violations. Petitioner asserts that where EPA has issued an NOV alleging CAA violations, the title V permit must include compliance schedules.

EPA's Response: EPA disagrees with Petitioner's conclusion. Petitioner has not sufficiently demonstrated to the Administrator that the permit is out of compliance with the Act, and therefore, EPA denies the petition with respect to this issue.

1. Enforcement and Regulatory History

EPA issued an NOV to EKPC on January 24, 2003, alleging PSD violations at the Spurlock Station. EPA filed a civil complaint in federal district court for the

Eastern District of Kentucky on January 29, 2004, alleging similar violations. *See United States v. East Kentucky Power Coop.* Case No. 04-34-KSF (E.D. KY). The alleged violations at Spurlock Station arose from EKPC's failure to operate Unit 2 in accordance with the stated purpose in its application. EKPC's construction permit application stated that all steam generated by Unit 2 would be used solely to generate electricity. However, in August 1992, EKPC began supplying steam to Inland Container. Further, EPA alleged that the increased steam demand created by connecting to and supplying steam to Inland Container violated the CAA because it resulted in an unpermitted significant net increase of emissions. EPA alleged that EKPC's physical changes constituted "major modifications" as defined in the Act and the Kentucky SIP. This claim flowed from EKPC's decision to uprate the boiler at Spurlock Unit 2, and subsequently operate it at heat input levels above the 4850 mmBtu/hr maximum heat input capacity included in its operating permit. EPA alleged in its NOV and complaint that EKPC did not obtain the required PSD permit prior to constructing or operating these alleged major modifications and has subsequently operated Spurlock station without installing or operating BACT, as required by the Act and the Kentucky SIP. On July 2, 2007, the United States and EKPC lodged a proposed consent decree in the U.S. District Court for the Eastern District of Kentucky. Information regarding the settlement can be found at http://www.epa.gov/compliance/resources/cases/civil/caa/eastkentuckypower.html. Notably, in the proposed consent decree, EKPC has disclaimed liability for the PSD, Kentucky SIP, New Source Performance Standards, and title V violations alleged in the United States' complaint.

As required by title V of the Clean Air Act, part 70, and the Kentucky SIP, EKPC submitted a title V permit application to KYDAQ for its Spurlock Station. Title V requires a facility to include in its application a description of how the facility will comply with all applicable requirements and a schedule of compliance for requirements with which the source is not in compliance at the time of permit issuance. *See* CAA 503(b); 40 C.F.R. § 70.5(c); and 401 KAR 52:020.

EKPC submitted the required title V permit application to KYDAQ; however, EKPC did not include PSD requirements in the application as applicable requirements, nor a compliance schedule, because the company does not believe PSD requirements have been triggered at the plant.

Petitioner requested that KYDAQ include, in EKPC's title V permit, requirements to obtain a PSD permit. Accordingly, Petitioner asserts that since EPA identified violations cited in the NOV and the complaint filed against EKPC the permit must address the violations and include a compliance schedule pursuant to which EKPC is required to obtain the requisite PSD permit and comply with BACT. As explained in the permit's Statement of Basis at page.1, and KYDAQ's Response to Comments, KYDAQ views the issue of PSD applicability as unresolved in light of the on-going litigation and indicated that depending on the outcome of the litigation, it may be required to reopen the permit. Accordingly,

KYDAQ did not include PSD requirements in the Spurlock Station permit as applicable requirements.

The Petitioner petitioned EPA to object, under CAA 505(b)(2), to the Spurlock Station permit, and require a compliance schedule. All sources subject to title V must have a permit to operate that assures compliance by the source with all applicable requirements. *See* CAA § 504(a); 40 C.F.R. § 70.1(b). If a source is not in compliance with applicable requirements, then the title V permit must also contain a schedule of compliance leading to the facility's compliance with applicable requirements. *See* CAA § 504(a); 40 C.F.R. §§ 70.1 (b), 70.6(c)(3). Such applicable requirements may include the requirement to obtain PSD permits that comply with applicable PSD requirements under the Act, EPA regulations, and state implementation plans. *See generally* CAA §§ 110(a)(2)(c), 160-69; 40 C.F.R. §§ 51.166, 52.21. If the state permitting authority includes in a title V permit a requirement that the source does not believe applies, the source may, after exhausting any applicable state administrative appeal processes, seek review in state court. That case would involve the source and the state permitting agency, but, absent intervention, not the U.S. EPA.

The Petitioner bases its petition on the fact that the Agency has issued an NOV and filed a complaint in U.S. District Court alleging PSD violations. Petitioner argues that the NOV and the allegations therein, coupled with the complaint, establish the applicability of PSD to Spurlock Station.[8] Petitioner concludes, therefore, that the lack of any PSD requirements or a compliance schedule demonstrates that the permit is not in compliance with the Act, and thus requires the permit to address the violations alleged in the NOV and complaint.

2. Discussion

Contrary to Petitioner's views, and as previously explained by EPA in declining to object to two title V permits issued to Georgia Power Company, the issuance of an NOV and/or the filing of a complaint alone is not sufficient evidence to make the requisite "demonstrat[ion]" under section 505(b)(2). *See generally In the Matter of Georgia Power Company, Bowen Steam – Electric Generating Plant, et al*, Final Order, dated January 8, 2007, at 5-9. Under section 113(a)(1), "[w]henever, on the basis of any information available to the Administrator, the Administrator finds that any person has violated or is in violation of any requirement or prohibition of an applicable implementation plan or permit, the Administrator shall [issue an NOV]." An NOV is simply one early step in the EPA's process of determining whether a violation has, in fact, occurred. It is not a final agency action and is not subject to judicial review. It is well-recognized that no legal consequences flow from an NOV, and an NOV does not have the force or effect of law. *See Pacificorp v. Thomas*, 883 F.2d 661 (9th Cir. 1988); *Asbestec Constr. Servs. v. EPA*, 849 F.2d 765, 768-69 (2nd Cir. 1988); *Union Elec. Co. v.*

[8] In its petition, Petitioner offers no evidence of PSD noncompliance, other than EPA's NOV and the United States' complaint.

EPA, 593 F.2d 299, 304-06 (8th Cir. 1979); and *West Penn Power Co. v. Train*, 522 F.2d 302, 310-11 (3rd Cir. 1975).

A complaint is simply "a pleading which sets forth a claim for relief," and includes a "short and plain statement of the claim that the [plaintiff] is entitled to relief ...." *See* Fed. R. Civ. P. 8(a). While a plaintiff may be subject to sanctions for filing a complaint that includes inaccurate allegations, *see* Fed. R. Civ. P. 11, the complaint does not in-and-of itself prove the facts plead. Rather, as the Eleventh Circuit has noted, when EPA files a complaint in a civil enforcement action, "if the defendant believes that the EPA has reached its conclusions based upon erroneous facts or an incorrect understanding of the law, the defendant may make legal and factual arguments in an independent forum—one that enables the defendant to utilize a panoply of pre-established procedural rights." *See TVA v. Whitman*, 336 F.3d 1236, 1241 (11th Cir. 2003).

Thus, both an NOV and a complaint are initial steps in the process of determining whether the source is in violation of any CAA requirements. These steps are commonly followed by additional investigation or discovery, information-gathering, and exchange of views that occur in the context of an enforcement proceeding and that are considered important means of fact-finding under our system of civil litigation. As a result, EPA believes that the fact of the issuance of an NOV or the filing of a complaint does not definitively establish the necessity of a compliance schedule for title V purposes.

Petitioner also points to the information contained in the NOV allegations, and appears to suggest that such information is sufficient to "demonstrate[]" PSD applicability, under CAA section 502(b)(2). However, information contained in an NOV (or a complaint) alone is not sufficient to demonstrate that a requirement is applicable for permitting purposes. EPA may consider an NOV's filing or complaint's issuance as a relevant factor when determining whether the overall information presented by the petitioner – in light of all the factors that may be relevant – demonstrates the applicability of a requirement for title V purposes. Other factors that may be relevant in this determination include the quality of the information, whether the underlying facts are disputable, the types of defenses available to the source, and the nature of any disputed legal questions, all of which would need to be considered within the constraints of the title V process. If, in any particular case, these factors are relevant and the Petitioner does not present information concerning them, then EPA may find that the Petitioner has failed to present sufficient information to demonstrate that the requirement is applicable.

Another factor that EPA considers is the potential impact enforcement cases and title V decisions have on one another, as illustrated by the following example. As is the case here, EPA could bring a civil judicial enforcement action for violations by a source of a substantive rule. The source and EPA would be engaged in litigation over the merits of the allegations of EPA's judicial complaint. Should EPA prevail in that enforcement proceeding, or should the source and EPA

propose to settle their differences – as has happened in this particular enforcement proceeding – then the court would enter judgment in the form of an order or consent decree requiring the source achieve compliance with the law either pursuant to the terms of a compliance order, or, at a minimum, by a date certain. (*In the Matter of Georgia Power Company, Bowen Steam – Electric Generating Plant, et al Final Order*, dated January 8, 2007; and *In the Matter of Lovett Generating Station Final Order*, Petition Number: II-2001-07, dated February 19, 2003). In the event of a proposed settlement, the enforcement proceeding would not be "final" or concluded until such time that the consent decree is entered by the court. Thus, should the proposed consent decree be entered by the court in the related enforcement action, KYDAQ and EKPC would need to appropriately respond by incorporating the compliance schedule(s) required by the consent decree into the title V permit. Specifically, the proposed consent decree requires EKPC to amend its title V permit within 180 days of entry of the consent decree to "include a schedule for all Unit-specific performance, operational, maintenance, and control technology requirements established by this consent decree including, but not limited to, emission rates, removal efficiencies, fuel limitations, tonnage limitations, and the requirement in Paragraph 72 pertaining to the surrender of SO_2 Allowances." Proposed Consent Decree, ¶ 166.

Separately, in the context of the issuance of a title V permit to the same source, the permitting authority may determine (on its own or as a result of an EPA objection) that the source is in non-compliance with the substantive rule (i.e., applicable requirement) that is the subject of the enforcement proceeding, and require in the title V permit that the source achieve compliance with the applicable requirement pursuant to a schedule of compliance. Under such circumstances, the source could challenge the permit, petition EPA for relief, and appeal to the appropriate circuit court. In these circumstances, the source and EPA could find themselves in two separate forums for litigating essentially the same issues - whether the substantive rule was violated and the appropriateness of a compliance schedule – which risks potentially different and conflicting results.

In light of the settlement lodged but not yet entered in the federal court enforcement action between the United States and EKPC, the fact that EKPC continues to dispute its PSD liability notwithstanding reaching that settlement with the United States, and Petitioner's sole reliance on the existence of an NOV and complaint in the enforcement action, I find that the petition does not "demonstrate" that the title V permit does not comply with the Clean Air Act. At this point, the PSD claims in the complaint have not been fully adjudicated and the proposed consent decree has not yet been entered in federal court, and thus, Petitioner has not met its burden of showing that the permit is not in compliance with the Act.

I note that, while the permit does not contain PSD as applicable requirements for Unit 2, it also does not provide any safe harbor from enforcement of PSD requirements. Thus, the permit does not disturb any ongoing or future

enforcement action against EKPC for violations of PSD requirements.[9] EPA believes that, considering these specific circumstances it would be premature to make a determination on PSD applicability and any NSR compliance schedule requirements. The appropriate path is to allow the PSD applicability issue to be fully resolved by the federal district court in the enforcement process before determining that the title V permit must contain such requirements.

For the reasons explained herein, EPA denies the petition with respect to this issue.

D. Construct and Operate Unit 3 in Accordance with Permit Application

Petitioner's Comment: Petitioner asserts that the permit omits a requirement that EKPC construct and operate Unit 3 in accordance with the plans and specifications submitted with the pre-construction permit application. The CAA and requires that a PSD applicant construct and operate the source consistent with the specifications of the permit application. 40 C.F.R § 52.21(r). This includes, but is not limited to, the fuel, control equipment, and maximum heat rating included in the permit application. Petitioner is requesting that the Administrator object to the permit and require that it be revised to include these requirements.

EPA's Response: EPA disagrees with Petitioner's conclusion. The permit is written based on the specifications, terms and conditions of the application submitted by EKPC, and as a pre-requisite, that application must be complete and accurate in order to comply with the applicable regulations. 401 KAR 52:020. Petitioner's reliance on 40 C.F.R § 52.21(r) to argue that the CAA requires that a PSD applicant construct and operate the source consistent with and according to the specifications provided in the permit application is misplaced – that regulation governs federally issued or delegated PSD permits. For Kentucky, which issues PSD permits pursuant to a federally approved SIP, the applicable and relevant federal regulation is set forth at 40 C.F.R. § 51.166(r)(1), which states that the SIP for an approved PSD program "shall include enforceable procedures to provide that approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the plan and any other requirements under local, State or Federal law." While Petitioner correctly notes the relevant state PSD law, Petitioner fails to recognize that under that law, the source must be operated "in accordance with the application [to construct]... or under the terms of an approval to construct." 401 KAR 51:017(16) (emphasis added). Because a PSD source in Kentucky that operates in accordance with its permit to construct has met

[9] In the ongoing case, *U.S. v East Kentucky Power Cooperative*, Case No. 04-34-KSF (E.D. KY), the Sixth Circuit recently ruled that EPA had not proven in its *Motion for Summary Judgment,* when and how frequently EKPC exceeded the 4,850 mmBtu/hr limit, therefore, that issue would have to be addressed at a future trial. The Court also ruled that EPA had not met its burden of proof required to establish the relationship between EKPC's uprating its boilers to 4 million pounds per hour of steam and an alleged corresponding increase in the heat input to the boiler.

the requirements of the applicable state and federal law, it is not necessary for KYDAQ to include language in the title V permit requiring EKPC to construct and operate Unit 3 consistent with the specifications of the PSD permit application. Therefore, EPA denies the petition with respect to this issue.

E. BACT Limits for Unit 3

Petitioner's Comment: As a general matter, Petitioner claims BACT limits established in prior title I permitting actions can be revisited in subsequent title V permitting processes if it is established that the historic BACT determination was erroneous. With regard to the Spurlock Station title V permit, Petitioner alleges that the permit contains erroneous BACT limits for Unit 3, and relies heavily on EPA's Order *In re Chevron Products Co.*, Petition No. IX-2004-08 (*Chevron*), to substantiate its claim.

EPA's Response: The Petitioner has failed to demonstrate that the Spurlock Station title V permit for Unit 3 is not in compliance with the applicable CAA requirements, including the requirements of the Kentucky SIP. CAA Section 505(b)(1). Further, as stated in *Chevron*, pursuant to EPA policy, the Agency generally does not object to the issuance of a title V permit due to concerns over BACT or related determinations made long ago during a prior reconstruction permitting process. *Id.* at 9; *see also* Letter to John S. Seitz to Robert Hodanbosi and Charles Lagges at page 2 (May 20, 1999).

Notwithstanding EPA's general policy not to object to the issuance of a title V permit due to concerns over BACT determinations made during a prior reconstruction permitting process, EPA clearly retains its authority to reopen a permit to reevaluate BACT determinations under limited circumstances. Specifically, EPA will reopen a permit when an emissions limit unit has not gone through the proper PSD permitting process, and therefore lacks one or more applicable requirements of the CAA in the draft or proposed title V permit. *See Chevron* at 11 n13. EPA exercised its authority on this basis to reopen the Chevron permit because the BACT limits were adopted under local district rules that were not approved by EPA and that provided an exemption from NSR requirements. The local district adopted the rule exemption 11 months prior to the submittal of Chevron's application and deleted it within two months after approving construction of the Chevron unit in question. Consequently, EPA concluded that there was insufficient information to make a determination as to whether the Chevron permit limits accurately reflected BACT or whether the NSR requirements were followed. However, in granting the *Chevron* title V petition on the BACT issue, EPA made it abundantly clear that it was doing so solely because the specific facts demonstrated degrees of deficiency and a possible compromise in the PSD permitting process. *See id.* at 11-13 and n13.

The scenario presented in this petition concerning the BACT limits for Unit 3 is quite distinguishable from *Chevron*. KYDAQ adopted the Unit 3 limits under

an EPA approved PSD program, and EPA and the public were given the opportunity to review and comment on these limits prior to the issuance of the final PSD permit in June 2002. At that juncture, Petitioner clearly had the opportunity to raise its concerns regarding the BACT limits for Unit 3, but for unknown reasons, it failed to do so. In this instance, Petitioner has not demonstrated, and there is nothing in the record to suggest any deficiency in the PSD permitting process or that Unit 3 BACT determination was unreasonable. (The Supreme Court held that EPA may act to block construction of a new major pollutant emitting facility if EPA finds that the state's BACT determination was unreasonable.) *Alaska Dep't of Environmental Conservation v. EPA*, 540 U.S. 461, 488 (2004). In addition, Petitioner has failed to demonstrate that the title V permit including the Unit 3 BACT limits, is not in compliance with the applicable CAA requirements.

For these reasons, and as explained more fully below, EPA denies the petition with respect to this issue.

1. Visible Emission BACT Limits

Petitioner's Comment: Petitioner claims the permit does not contain visible emission BACT limits for PM and sulfuric acid mist (SAM) from Unit 3. Any new or modified major source must have a permit requiring BACT and BACT is expressly defined as an "emissions limitation including a visible emission standard," for each "regulated NSR pollutant." 401 KAR 51:001, Section 1(25).

EPA's Response: Consistent with KYDAQ's Response to Comments, EPA concludes that opacity is not an NSR regulated pollutant, and thus, there is no applicable federal or state requirement to have a BACT opacity limit. *See* KYDAQ's Response to Comments at page 46; *see also Knauf Fiber Glass,* 8 E.A.D. 121 (EAB 1999) (stating that an opacity limit "is not a requirement of the federal PSD program"). It is permissible for an agency to use opacity as an emission limitation. Contrary to Petitioner's assertion, the inclusion of visibility in the definition of BACT merely clarifies that a visible emission standard is an acceptable form of a BACT limit for an NSR regulated pollutant. *See Alabama Power v. Costle*, 636 F.2d 323, 408 (D.C. Cir. 1979) (emphasis added). Accordingly, opacity may be used as an indicator of particulate matter, fumes, gases or vapor but it is not independently regulated. This position is consistent with EAB and state decisions finding that PSD does not necessarily require opacity limits. *See generally In re Amerada Hess Corp. Port Reading Refinery*, PSD Appeal No. 04-03, slip op. at 11 (EAB Feb. 1, 2005); *In re Air Pollution Control Construction and Operation of a 500 MW Pulverized Coal-Fired Plant Known as Weston Unit 4* in Marathon County, Wisconsin, Wis. Div. of Hearing and Appeals, Case No. IH-04-21 (Feb. 10, 2006). The Spurlock permit as written provides direct and specific limits for the pollutants identified by Petitioner (PM and SAM). Further, the regulated NSR pollutant PM/PM_{10} will also be monitored by PM continuous emission monitoring system (CEMS), thus providing a continuous method for ensuring compliance with the particulate emissions standards. Because

opacity is not an NSR regulated pollutant, and there is not an applicable federal or state requirement to have a BACT opacity limit, EPA denies the petition with respect to this issue.

2. Sulfur Dioxide (SO_2) Limit

Petitioner's Comment: The SO_2 limit for Unit 3 does not represent BACT as of June 2002, when construction commenced on Unit 3. Other permits issued prior to the time construction commenced on Unit 3, contain much lower SO_2 limits. Therefore, these lower limits must be presumed to be BACT for Unit 3 since EKPC has not demonstrated that it is technologically infeasible.

EPA's Response: As stated above, Petitioner has failed to demonstrate that the SO_2 limit for Unit 3 contained in this title V permit is not in compliance with the applicable CAA requirements, including the requirements of the Kentucky SIP. CAA § 505(b)(1). Based on the record before the Agency, the existing SO_2 limit for Unit 3 contained in this title V permit represents BACT for Unit 3. This BACT determination was made during a prior permitting action, at which time Petitioner had the opportunity to raise the issue but failed to do so. *See* KYDAQ Response to Comments at page 32. As explained above, the Agency generally will not object to a title V permit due to concerns over BACT determination made in a prior PSD preconstruction permitting process. *See discussion* Section E, *supra.*

As a basis for its position, Petitioner provides examples of lower limits established for SO_2 at similar sources throughout the country. However, Petitioner fails to provide any analysis to demonstrate that these BACT limits are appropriate for Unit 3. The other sources that Petitioner references are distinguishable from Unit 3 based on several factors, including plant size and fuel type. It is well recognized that due to characteristics of individual plant processes, the application of identical technology may not yield identical emission limits. *See Newmont Nevada Energy Investments, LLC TS Power Plant*, PSD Appeal No. 05-04, slip op. 16-17 (EAB Dec. 21, 2005); *In re. Knauf Fiberglass GmbH*, 8 EAD at 143 (EAB 1999). Petitioner refers to the PSD permit for the AES Puerto Rico facility without pointing out that the AES permit has a specific and distinguishable condition that limits the fuel the source can burn to a maximum of 1 percent sulfur. Spurlock Unit 3 has no such limits and is permitted to burn coal in the 4.5 percent sulfur range. In arguing that the limit in the AES Puerto Rico permit is BACT for Unit 3, Petitioner disregards the "case-by-case" site specific nature of the BACT analysis. CAA § 169(3) and 401 KAR 51.001. Petitioner has failed to establish that KYDAQ's BACT determination for the SO_2 limit was unreasonable, or otherwise not in compliance with the applicable CAA requirements. *See generally Alaska Dep't of Environmental Conservation,* 540 U.S. 461, 488 (2004). For these reasons, EPA denies the petition with respect to this issue.

3. Particulate Matter (PM) Limit

Petitioner's Comment: The PM limit for Unit 3 does not represent BACT for Unit 3 as of the date of construction on June 22, 2002. Other permits issued prior to the commencement of Unit 3's construction contain much lower PM limits, and therefore, these lower limits must be presumed to be BACT for Unit 3 unless EKPC demonstrates that such limits are not technically feasible or cost effective.

EPA's Response: As stated above, Petitioner has failed to demonstrate that the title V permit is not in compliance with the applicable CAA requirements, including the requirements of the Kentucky SIP. CAA, Section 505(b)(1). The existing PM limit established in the permit represents BACT for Unit 3. This BACT determination was made during a prior permitting action, at which time Petitioner had the opportunity to raise the issue but failed to do so. *See* KYDAQ Response to Comments at page 33. Further, the Agency generally will not object to a title V permit due to concerns over BACT determination made in a prior PSD preconstruction permitting process. *See discussion* Section E, *supra.*

As a basis for claiming that the Unit 3 PM limit of 0.015 lb/mmBtu (filterable) does not represent BACT, Petitioner references another source (Northampton facility) that is similar to Unit 3 but fails to recognize that the source has characteristics that influence PM emissions and are distinct from Unit 3, such as fuel type (i.e., Northamption burns anthracite as opposed to high sulfur bituminous coal used in Spurlock Unit 3). *In re BP Cherry Point*, PSD Appeal No. 05-01, slip op. 21 (EAB June 21, 2005); and *In re Prairie State Generating Co.* PSD Appeal No. 05-05 slip op. at 71 (August 24, 2006). Moreover, Petitioner neglects to mention that the PM limit for Unit 3 is actually lower than some limits imposed on other similar facilities (AES Beaver Valley and Archer Daniel Midland) prior to June 2002. Overall, Petitioner fails to provide any analysis to demonstrate that its preferred PM BACT limit for this pollutant is appropriate for Unit 3 and in so doing, Petitioner continues to disregard the "case-by-case" site specific nature of the BACT analysis. CAA § 169(3) and 401 KAR 51.001. In its petition, the Petitioner has failed to establish that KYDAQ's BACT determination for PM limit was unreasonable for Unit 3, or otherwise not in compliance with the applicable CAA requirements. *See generally Alaska Dep't of Environmental Conservation,* 540 U.S. 461,488 (2004). For these reasons, EPA denies the petition with respect to this issue.

4. Nitrogen Oxides (NO_x) Limit

Petitioner's Comment: The NO_x limit for Unit 3 does not represent BACT for Unit 3 as of the date of construction on June 22, 2002. Other permits issued prior to the commencement of Unit 3's construction contain much lower NO_x limits and therefore, these lower limits must be presumed to be BACT for Unit 3 unless EKPC demonstrates that such limits are not technically feasible or cost effective.

EPA's Response: As stated above, Petitioner has failed to demonstrate that the title V permit is not in compliance with the applicable CAA requirements, including the requirements of the Kentucky SIP. CAA § 505(b)(1). The existing NO_x limit established in the permit represents BACT for Unit 3. This BACT determination was made during a prior permitting action, at which time Petitioner had the opportunity to raise the issue but failed to do so. *See* KYDAQ Response to Comments at page 33. As explained previously, the Agency generally will not object to a title V permit due to concerns over a BACT determination made in a prior PSD preconstruction permitting process. *See discussion* Section E, *supra.*

As a basis for its position that the Unit 3 NO_x limit of 0.07 lb/mmBtu does not represent BACT, Petitioner provides examples of lower limits established for NOx at facilities that use boilers similar to Spurlock Unit 3, but Petitioner fails to recognize that these other facilities have striking differences that distinguish them from Unit 3. For instance, the BMCP facility cited by Petitioner is a 20 megawatts (MW) facility burning 0.6 percent sulfur coal, while Unit 3 is a 270 MW unit burns high sulfur bituminous coal. Moreover, Petitioner fails to acknowledge that the NO_x limit for Unit 3 is consistent with the NO_x limits imposed on similar facilities (NEVCO-Sever, Kentucky Mountain Power and JEA Northside). In presenting its position, Petitioner does not provide any analysis to demonstrate that its preferred BACT limits for NO_x is appropriate for Spurlock Station Unit 3. In so doing, Petitioner continues to disregard the "case-by-case" site specific nature of the BACT analysis. CAA § 169(3) and 401 KAR 51.001. Because Petitioner has failed to establish that KYDAQ's BACT determination for the NO_x limit was unreasonable for Unit 3, or otherwise not in compliance with the applicable CAA requirements, EPA denies the petition with respect to this issue.

5. SAM Limit

Petitioner's Comment: The SAM limit for Unit 3 does not represent BACT for Unit 3 as of the date of construction on June 22, 2002. Other permits issued prior to the commencement of Unit 3's construction contain much lower SAM limits and therefore, these lower limits must be presumed to be BACT for Unit 3 unless EKPC demonstrates that such limits are technically infeasible or not cost effective.

EPA's Response: As stated above, Petitioner has failed to demonstrate that the title V permit is not in compliance with the applicable CAA requirements, including the requirements of an applicable implementation plan. CAA § 505(b)(1). The existing SAM limit established in the permit represents BACT for Unit 3. This BACT determination was made during a prior permitting action, at which time Petitioner had the opportunity to raise the issue but failed to do so. *See* KYDAQ's Response to Comments at page 33. Further, the Agency generally will not object to a title V permit due to concerns over BACT determination made in a prior preconstruction process. *See discussion* Section E, *supra.*

As a basis for claiming that the Unit 3 SAM limit of 0.07 lb/mmBtu does not represent BACT, Petitioner references another source (AES Puerto Rico) that is similar to Spurlock Unit 3, but AES Puerto Rico is clearly distinguishable based on the sulfur content of the fuel. Again, Petitioner disregards the "case-by-case" site specific nature of the BACT analysis. CAA § 169(3) and 401 KAR 51.001. Petitioner references the SAM limit contained in the AES Puerto Rico PSD permit but fails to take in consideration that this limit is based on the low sulfur content of the fuel that is also required by the permit. As stated above, Unit 3 has no such limits on coal sulfur content, and is permitted to burn coal in the 4.5 percent sulfur range. Based on these circumstances, the SAM limit for Unit 3 is entirely consistent with other permits where the facility is burning a higher sulfur coal (e.g., Greene Energy Recovery Project, Permit No. PA-30-00150, burning high sulfur waste coal with a 0.0060 lb/mmBtu limit). Since Petitioner has failed to establish that KYDAQ's BACT determination for the SAM limit was unreasonable for Unit 3, or otherwise not in compliance with the applicable CAA requirements, EPA denies the petition with respect to this issue.

F. Enforceable Limits and Monitoring to Ensure Continuous Compliance For Unit 3

Petitioner's Comment: Petitioner claims that the limits for Unit 3 are not enforceable and do not require monitoring to ensure continuous compliance. A title V permit must require monitoring sufficient to ensure that the source is in continuous compliance with the permit limits during the relevant time periods. 40 C.F.R. § 70.6(a)(3)(i)(B). This permit contains insufficient monitoring to ensure compliance with PM and hazardous air pollutant (HAP) limits, including hydrogen fluoride (HF). The permit establishes opacity as a surrogate for PM/PM_{10} compliance and if the source violates the opacity surrogate it is required to conduct a stack test. However, the permit does not explicitly state that a violation of the opacity surrogate range is a violation of the PM limit. In addition, an annual stack test is insufficient to insure compliance with the HAPs limits.

EPA's Response: Petitioner requests that the Administrator object to the permit and require KYDAQ to modify the permit to explicitly state that: (1) COMs can be used to establish violations of the opacity limit, and (2) exceedance of the Compliance Assurance Monitoring (CAM) level for opacity is a violation of the PM standard, in addition to triggering corrective action under the CAM rule. However, EPA has determined that Petitioner's request is inconsistent with the requirements of CAM, Kentucky's SIP and title V. As explained previously, an agency may use opacity as an emission limit for an NSR regulated pollutant but there is no federal or state requirement to have an opacity limit in a permit other than those contained in the applicable CAM regulation. Petitioner's comment fails to recognize that exceedance of the CAM level for PM or HAPs monitors is not a permit violation, but rather a trigger for corrective action under the CAM rule.

Notwithstanding Petitioner's assertion, pursuant to the CAA §§ 114(a)(3), and 504(c), a title V permit is required to provide for "enhanced monitoring" and submission of compliance certification. In *Natural Resources Defense Council, Inc. (NRDC) v. EPA,* 194 F.3d 130 (D.C. Cir.1999), the court confirmed that CAM standards assured compliance as required by the CAA. "CAM enhances monitoring by requiring each major source owner to design a site-specific monitoring system sufficient to provide a reasonable assurance of compliance with emissions standards." *Id.* If CEMS or COMS is required, the Act requires that the source use that system to satisfy the CAM rules. 40 C.F.R. § 64.3(d). In the absence of continuous monitoring, CAM requires that indicators be established to provide an indication of whether or not a control device is working properly. 40 C.F.R. § 64.3(a).

With regard to Unit 3, since a PM CEMS has not yet been installed at Unit 3, opacity is selected as an indicator of PM compliance, as are electrostatic precipitator (ESP) transformer/rectifier set voltages and currents. This is consistent with 40 C.F.R. § 64.3(d), which states in part that "if an opacity standard applies to the pollutant-specific emissions unit, such limit may be used as the appropriate indicator." Since the specific voltage and current levels that indicate proper levels of ESP performance will vary from unit-to-unit, CAM requires testing at Unit 3 to establish the opacity level that will be used as an indicator of particulate matter emissions. As the permit states "the opacity indicator level shall be established at a level that PM emissions are in compliance when opacity is equal to or less than the indicator level." Permit at B4(b) and 40 C.F.R. § 64.4(c)(1).

Petitioner's assertion that EKPC's excess emissions of opacity should be independently considered as violations of the PM standard is unsubstantiated. The Petitioner fails to demonstrate where the permit is lacking enforceable terms and conditions. The permit requires EKPC to install COMS, which includes installing, calibrating, operating, and maintaining the continuous monitoring system for accurate opacity. *Id* at B4(a). The permit clearly sets forth that the source will monitor COMS readings and record pressure drop across the baghouse once per shift, and Unit 3 is also subject to recordkeeping and reporting requirements. Regarding opacity, the permit requires that the source conduct tests to establish the level of opacity that will be used as an indicator of PM emissions. *See id* at B4(b). Pursuant to 40 C.F.R § 64.4(e), the source is required to conduct initial performance tests within 180 days of the permit issuance to establish the opacity and PM correlation, pursuant to 40 C.F.R § 64.4(e). Similarly, the permit requires EKPC to conduct an initial performance test to establish the parameter monitoring for the control device and upon completion of the initial performance test, the appropriate monitoring range will be incorporated into the permit. EPA has consistently found the combination of parametric monitoring for control of PM, monthly opacity reading, testing and reporting to be adequate. *See e.g., In the Matter of GCC Dacotah Cement Manufacturing Plant Final Order,* Petition Number: VIII-2006-03 at page 10 (June 2007).

Pursuant to 40 C.F.R. § 64.4(c)(1) and the CAM plan filed on October 27, 2005, opacity must be used as an indicator of PM emissions in conjunction with monitoring of the ESP's transformer/rectifier voltage and current levels. As stated above, in order to provide reasonable assurance that PM emissions are in compliance, the permit establishes opacity (20 percent) at a range that is set well below the limit which would constitute a violation. *See* B4(m)(ii) and 40 CFR § 64.4(c)(1).

Further, Petitioner's assertion regarding the lack of monitoring for HAPs limits, including HF, is also incorrect. The permit specifies methods for ensuring compliance with applicable requirements for volatile HAPs, mercury, hydrogen chloride, HF, beryllium, lead and metals. *Id.* In accordance with CAM, the permit requires EKPC to conduct annual stack tests and to use a "grab bag" sampling of the fuel content to establish correlation between HAP content and HAP emissions. EPKC is required to demonstrate compliance with these emission limits annually to validate the correlation between grab samples HAP content and HAP emissions. After three years of demonstrating compliance and correlation between the samples and emissions, the permit affords EKPC the opportunity to use the quarterly grab samples as a surrogate for compliance testing. However, the permit indicates that the annual stack testing not the "grab samples" will be used to determine a violation of the emission limit. Further, the permit states that the compliance with the sulfur dioxide emissions indicates compliance with HF limits. The emission unit uses a dry lime scrubber to control the SO_2 and HF emissions by injecting lime into the scrubber line. The permit requires the source to conduct a performance test to determine a lime injection rate and this method will be used to determine continuous compliance with the HF emission limit.

The position taken by Petitioner that the permit must specify "enforceable limits" for each of the monitored parameters is also not supported by the final CAM rule. As EPA explained in the preamble to that rule,

> The CAM approach builds on the premise that if an emissions unit is proven to be capable of achieving compliance as documented by a compliance or performance test and is thereafter operated under the conditions anticipated and if the control equipment is properly operated and maintained, then there will be a reasonable assurance that the emissions unit will remain in compliance. In most cases, this relationship can be shown to exist through results from the performance testing without additional site-specific correlation of operational indicators with actual emission values ...
>
> ... the presumptive approach for establishing indicator ranges in part 64 is to establish the ranges in the context of performance testing. To assure that conditions represented by performance testing are also generally representative of anticipated operating conditions, a performance test should be conducted under conditions specified by the applicable rule or, if not specified, generally under conditions representative of maximum emission

> potential under anticipated operating conditions. In addition, the rule allows for adjusting the baseline values recorded during a performance test to account for the inappropriateness of requiring that indicator conditions stay exactly the same as during a test. The use of operational data collected during performance testing is a key element in establishing indicator ranges; however, other relevant information in establishing indicator ranges would be engineering assessments, historical data and vendor data. Indicator ranges do not need to be correlated across the whole range of potential emissions.

62 Fed. Reg. 54909, 54926 (October 22, 1997). In addition, EPA has explained that established CAM parameters are not enforceable limits. The CAM rule preamble addressed this by pointing out that:

> The obligation to correct excursions as expeditiously as practicable is the enforceable component associated with establishing an indicator range under part 64. Part 64 does not establish that an excursion from an indicator range constitutes an independent violation by itself.

Id. 54931. *See also id* at 54928. Thus, CAM provides a reasonable assurance of compliance with emission limits and consequently, the adoption of CAM as "enhanced monitoring" meets the requirement of the CAA but does not convert the CAM parameters to enforceable permit limits. Accordingly, EPA denies the petition with respect to this issue.

G. BACT Limits for Unit 4[10]

In arguing that the Unit 4 BACT limits are not in compliance with the PSD requirements of the Clean Air Act, Petitioner describes the BACT selection process, but EPA has determined that Petitioner's arguments concerning the BACT limits for Unit 4 fail to consider the critical "case-by-case" analysis that defines BACT. CAA § 169(3) and 401 KAR 51.001. PSD permit decisions depend heavily on site-specific analysis, and this case-by-case decision-making inevitably results in substantive differences from permit to permit. *See In re Cardinal FG Co.*, PSD Appeal No. 04-04, slip op. at 11 (Explaining that "BACT is a site-specific determination); *In re Old Dominion Elec. Coop.*, 3 E.A.D. 779, 788-89 (Adm'r1992) ("PSD permit determinations are made individually under the Act on a case-by-case basis"). Petitioner further ignores that a BACT analysis does not necessarily yield a single objective and correct BACT determination that can be applied to all plants. *See Alaska Dept. of Environmental Conservation.* 540 U.S. 461, 488 (2004). BACT is a site-specific determination resulting in the selection of

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[10] Unlike the BACT issues regarding the previously permitted Unit 3, *see* Section E *supra*, EPA policy has maintained the Agency's discretion to object to the issuance of a title V permit due to concerns over BACT when the PSD process is merged with the title V process. *See* Letter to John S. Seitz to Robert Hodanbosi and Charles Lagges at page 2 (May 20, 1999).

an emission limitation that represents application of control technology appropriate for the particular facility. *See In re Three Mountain Power*, LLC, 10 E.A.D. 39, 47 (EAB 2001).

As evidenced in EPA's response to Petitioner's BACT Unit 3 challenge, *see* section IV.E., *supra,* Petitioner continues to overlook the fact that a BACT analysis may consider certain distinguishable factors at a particular facility when setting emission limit, *inter alia*, the type of fuel that will be used, type of source, size of the source and geographic considerations. A high degree of technical judgment must also be exercised in any BACT analysis for coal-fired plants given the wide variety of coals (e.g., anthracite and sub-bituminous) and coal-fired facilities (e.g., pulverized coal, and CFB) available for permitting authorities to consider. *In re BP Cherry Point*, PSD Appeal No. 05-01 slip op. at 71 (EAB June 21, 2005); *In re Prairie State Generating Co.*, PSD Appeal No. 05-05 slip op. at 71 (EAB August 24, 2006).

While EPA agrees with Petitioner's position that BACT requires a forward-looking analysis, BACT also takes into account that the selected limit must be "achievable for such facility." *Newmont Nevada Energy Investments, LLC TS Power Plant*, PSD Appeal No. 05-04, slip op. 16-17 (EAB Dec. 21, 2005). Several EAB decisions reflected this position and explained that "the underlying principle of all these PSD cases is that PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but those limits must also reflect consideration of any practical difficulties associated with using the control technology." *In re Kendall New Century Dev.*, PSD Appeal No. 03-01, slip op. at 17 (EAB April 29, 2003); *Three Mountain Power,* 10 E.A.D at 38 and 47. The permit issuer must be given some flexibility and "may take into account the absence of long-term data, or the unproven long-term effectiveness of the technology, in setting emissions limitation that is BACT for a facility." *Newmont,* slip op. at 18; and *In re Cardinal FG Co.,* PSD Appeal No. 04-04 (EAB Mar. 22, 2005). The Supreme Court has made it clear that "Congress entrusted state permitting authorities with the initial responsibility to make BACT determinations 'case by case' § 7479(3). *See Alaska Dept. of Environmental Conservation.* 540 U.S. 461, 488 (2004). A state agency, no doubt, is best positioned to adjust for local differences in raw materials or plant configurations, differences that might make a technology 'unavailable' in a particular area." *Id.*

Regarding Petitioner's reliance on the draft NSR Workshop Manual (NSR manual), the EAB has ruled that although the NSR manual provides a framework that assures adequate consideration and consistency within the PSD permitting program, it is not a binding Agency regulation and as such, strict application of the methodology described therein is not mandatory. *In re Tondu Energy Co.*, 9 E.A.D. 710, 719 (EAB 2001); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 183 (EAB 2000); *Three Mountain Power* at 42. Since the NSR manual has not been incorporated in the Kentucky SIP, as long as the state conducts careful and detailed analysis of the

criteria identified in the regulatory definition of BACT, KYDAQ is not required to strictly adhere to the manual.

1. Sulfur Dioxide (SO_2) BACT Limits and Low Sulfur Coal

Petitioner's Comment: Petitioner claims that the BACT determination for Unit 4 failed to consider lower sulfur coal as a method to reduce sulfur dioxide (SO_2) emissions. EKPC and KYDAQ are required to determine whether lower pollution rates could be achieved by switching to a cleaner fuel. EKPC attempted to justify an SO_2 BACT limit higher than the limits set for similar facilities by relying on the fact that Unit 4 will use high sulfur coal, but its own analysis shows that using Powder River Basin (PRB) coal or low-sulfur eastern bituminous coal as the fuel for Unit 4 would reduce SO_2 emissions by 1,700 or more tons per year and would be cost effective.

EPA's Response: In reviewing Petitioner's request that the Administrator object to the permit because it does not include an accurate BACT limit for SO_2, EPA reviewed the BACT determination provided by KYDAQ and EKPC. Without deciding the merits of Petitioner's claim regarding the cost effectiveness of the various coal options considered by for Unit 4, EPA has determined that EKPC and KYDAQ have not provided an adequate explanation for their determination that the design basis coal is the BACT fuel for Unit 4. In particular, EPA finds that KYDAQ and EKPC have failed to provide a complete justification for excluding low sulfur eastern bituminous coal as BACT for limiting SO_2 emissions from this project. Accordingly, the Administrator grants the petition on the narrow issue of the selection of SO_2 BACT, limits and directs KYDAQ and EKPC to provide a complete analysis to support the selection of the design coal as BACT.

EPA has traditionally utilized a 5-step, top-down process for determining whether BACT emission limits for each PSD-regulated pollutant considered in a permitting decision meet the statutory criteria: (1) identify all potentially applicable control options (2) eliminate technically infeasible control options; (3) rank remaining technologies by control effectiveness; (4) eliminate control options from the top down based on energy, environmental, and economic impacts; and (5) select the most effective option not eliminated as BACT. *See In re Prairie State Generating Co.*, 13 E.A.D. ___, PSD Appeal No. 05-05, slip op. at 14-18 (EAB Aug. 24, 2006) (summarizing and describing steps in the top-down BACT analysis). *Accord In re Three Mountain Power, L.L.C.,* 10 E.A.D. 39, 42-43 n.3 (EAB 2001); *In re Knauf Fiber Glass, GmbH,* 8 E.A.D. 121, 129-31 (EAB 1999); and *In re Hawaii Electric Light Co.,* 8 E.A.D. 66, 84 (EAB 1998). In this case, EKPC and KYDAQ used this 5-step, top-down process to determine the BACT emission limits, including the SO_2 limit, contained in the permit for Spurlock Unit 4. *See* EKPC Supplemental BACT Analysis for Spurlock Unit 4 (January 12, 2006) at 2-5 (describing this process as its "BACT Methodology"); and KYDAQ Permit Statement of Basis (February 3, 3006) at 22 (explaining that BACT limits for Unit 4 were determined by using EKPC's BACT analysis).

In responding to Petitioner's previous comments regarding the use of lower sulfur coals in determining the SO_2 BACT for Unit 4, KYDAQ said it did not "concur that a limit restricting the coal sulfur content is appropriate or necessary for this type of unit, nor is the Division aware of any other permits for this type of facility that contain a limit in the percentage of sulfur that the fuel can contain." KYDAQ's Response to Comments (June 1, 2006) at 54; *see also* KYDAQ Permit Statement of Basis at 23-24 (describes the BACT limit for SO_2 without any discussion of coal choice or coal sulfur content). This response is insufficient because it does not provide any explanation as to why KYDAQ did not consider selection of a lower sulfur coal "appropriate or necessary" for achieving BACT at Unit 4 based on the applicable permitting criteria.[11] While permitting authorities have discretion in making the case-by-case technical assessments necessary to determine BACT for a specific source, in exercising that discretion, they must provide a reason for rejecting a specific control technology as BACT based on the applicable criteria in the Clean Air Act and its relevant implementing regulations. *See Indeck-Elwood*, 13 E.A.D. ___, PSD Appeal No. 03-04, slip op. at 29 (EAB Sept. 27, 2006) ("A permit issuer must, therefore, articulate with reasonable clarity the reasons for its conclusions and must adequately document its decision making.") and cases cited therein. Accordingly, in order to justify the SO_2 BACT selected for this project, KYDAQ needs to provide additional analysis and/or a justification for its determination that use of lower sulfur coal was not an achievable option for Spurlock Unit 4. *See Inter-Power of New York*, 5 E.A.D. 130, 145-49 (EAB 1994) (upholding PSD permit for a CFB boiler where petitioners claimed lower sulfur coal would have been used, but where the record showed that the permit's SO_2 limit was within the range of SO_2 limits of similar projects that had recently been issued PSD permits).

Given that KYDAQ's Permit Statement of Basis explains that BACT limits for Unit 4 were determined after considering the applicant's BACT analysis, *id.* at 22, EPA has also examined EKPC's SO_2 BACT analysis to determine if it provides an adequate basis for selection of the design basis coal as BACT, *see* EKPC Supplemental BACT Analysis for Spurlock Unit 4 (January 12, 2006) at 5-8. Upon complete examination, EPA finds that EKPC's analysis is also deficient because it does not explain (based on the BACT criteria) why one coal type – low sulfur eastern bituminous coal – was excluded as BACT for this project. Using the 5-step, top-down process for determining the SO_2 BACT emission limits, at step one, EKPC identified the use of three potential types of coal for use as fuel in Unit 4 and examined the potential for controlling SO_2 emissions: high-sulfur western Kentucky

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[11] EPA understands that permitting authorities have issued PSD permits for CFB boilers that contain SO_2 BACT emissions limits established by controlling the sulfur content of coal fuel used at the facility. *See, e.g., AES Puerto Rico*, 8 E.A.D. 324, ____ (near n3) (EAB 1999) (upholding issuance of a PSD permit for a CBF boiler that contained BACT limits on SO_2 emissions achieved through "a combination of three control strategies: 1) CFB boilers with limestone injection, 2) low sulfur coal (maximum sulfur content of 1.0%), and 3) an add-on dry scrubber").

coal (DB coal), PRB coal, and low sulfur eastern bituminous coal.[12] Supplemental BACT Analysis for Spurlock Unit 4 (January 12, 2006) at 6-7. From the analysis, it does not appear that EKPC eliminated any of these three coal options as technically infeasible at Step two. *See id.*

In accordance with Step three of the BACT analysis, EKPC provided information regarding the SO_2 potential for the each of three coal types: 0.8 for PRB coal, 1.23 for low sulfur eastern bituminous coal, and 9 for DB coal. *Id.* at 7. In Step four, EKPC provided an economic analysis of the SO_2 control achieved with each coal, including total, average, and incremental costs. In examining the control costs of the various coals considered, EKPC's analysis provides the following:

	Total Coal Cost (approx. $)	Difference in Cost (approx. $)	Average Control Cost ($/ton SO_2 removed)	Incremental Control Cost ($/ton SO_2 removed)
Design (DB) coal	30,662,842	baseline	283	baseline
PRB coal	76,650,000	45,987,158	8,033	23,733
Low sulfur E. Bit. coal	45,715,846	15,053,003	3,092	7,898

Supplemental BACT Analysis at 7-8.[13] *See also Inter-Power of New York*, 5 E.A.D. at 135 (explaining that BACT economic analysis usually involves an evaluation of two costs – "the total cost per ton of control for the pollutant" and "the comparative cost-effectiveness of various control options to determine their incremental cost-effectiveness"). In other words, EKPC determined that using PRB coal instead of DB coal would increase total fuel costs by approximately $46 million and would cost $23,733 more per ton of additional SO_2 control. EKPC then

[12] EKPC's analysis also includes relevant information for washed DB coal, but as will be explained in § 7c *infra*, coal washing is considered to be a supplemental SO_2 control option considered after, and in addition to, the selection of primary SO_2 controls, such as coal to be used in the boiler. Accordingly, EPA's review of the SO_2 BACT analysis with regard to coal choice is limited to these three different types of coal and excludes washed DB coal.

[13] EKPC has provided somewhat different cost figures in its response to the Title V petition. *See* Response to title V Petition at page 19. Since the response does not provide any information regarding the basis of the new figures and KDAQ's Supplemental BACT Analysis was before KDAQ when it issued the permit, EPA's review will focus on the information provided in KDAQ's Supplemental BACT Analysis.

eliminated PRB coal as "not economically viable" given total costs. Supplemental BACT Analysis at 7. After examining incremental costs, EKPC determined that the design basis coal was "the most economical for Unit 4," and based on this assessment, EKPC then selected the design basis coal as BACT for SO_2 emissions. *Id.* at 8.

However, EKPC's BACT selection in this instance is deficient because the analysis does not demonstrate that use of low sulfur eastern bituminous coal is not achievable for this source considering technical feasibility or economic, environmental, or energy impacts. *Indeck-Elwood*, slip op. at 77 (*citing Knauf Fiber Glass*, 8 E.A.D. 121, 130 (EAB 1999). Since EKPC's analysis shows that low sulfur eastern bituminous coal has a lower SO_2 potential than the DB coal (1.23 compared with 9), EKPC must provide a basis for excluding that option as a BACT and selecting a less stringent emission limit associated with the DB coal. EKPC's Supplemental BACT analysis does not sufficiently address the economic, environmental, or energy impacts of using low sulfur eastern bituminous coal. *See id.* at 7-8. While EKPC determined that the design coal was "the most economical", this does not demonstrate that use of low sulfur eastern bituminous coal is economically infeasible for this source. *See, e.g., Masonite Corp.*, 5 E.A.D. 551, 564 (EAB 1994) (Determining whether use of a technology is cost effective usually involves a comparison of the control option's cost-effectiveness "with what other companies in the same industry have been required to pay in recent BACT determinations to remove a ton of the same pollutant. In most cases, a control option is determined to be economically achievable if its cost-effectiveness is within the range of costs being borne by other sources of the same type to control the pollutant.") (citing *Inter-Power of New York*, 5 E.A.D. at 135).

Accordingly, the Administrator is granting this petition with respect to the issue of low sulfur coal and remanding the permit to KYDAQ and EKPC for further explanation and/or analysis regarding the choice of the design basis coal as BACT for SO_2 and, if necessary after such analysis, for adjustment of the SO_2 limit to appropriately reflect BACT. *See Indeck-Elwood*, slip op at 83 (remanding a specific BACT determination to the permitting authority after finding the record did not provide a sufficient explanation for the decision making process used to set the emission limit). In so doing, EPA is not concluding that the Unit 4 permit's SO_2 limit does not represent BACT – only that the present permit record does not provide EPA (or the public) sufficient information to make a reasonable decision as to the adequacy of the BACT determination.

2. Sulfur Oxide (SO_2) BACT Limit and Coal Washing

Petitioner's Comment: Petitioner claims that the SO_2 emission limit for Unit 4 is too high because the BACT determination failed to consider coal washing as a method to reduce SO_2 emissions. KYDAQ did not provide an adequate basis for concluding that coal washing was not an effective SO_2 reduction technique. The

permit also fails to recognize that coal washing must be considered for all coal types in the BACT determination, not just for the EKPC's preferred source of coal.

EPA's Response: Contrary to Petitioner's assertions, KYDAQ and EKPC did consider the feasibility of coal washing as a way to limit SO_2 emissions from this project. *See generally* EKPC Supplemental BACT Analysis at 8-9 and related tables at 7, 8; KYDAQ's Response to Comments at 54-56. KYDAQ determined that washed DB coal was not BACT because "coal washing is not uniformly effective in reducing sulfur in [the design basis] coal." KYDAQ's Response to Comments at 56. Such a determination is consistent with the EAB's determination that "a permitting authority must be allowed a certain degree of discretion to set the emissions limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the permittee to achieve compliance consistently." *Masonite Corporation* at 551 and 560-561.

While Petitioner argues that KYDAQ's only support for its determination is a website, Petitioner does not provide any information showing that coal washing is a consistently effective mechanism for reducing sulfur in eastern coal or provide information showing that KYDAQ's analysis "was so flawed as to be clearly erroneous." *Inter-Power of New York*, 5 E.A.D. at 146. Moreover, in addition to the website, KYDAQ also based its coal washing determination on EKPC's BACT analysis. *See* Permit Statement of Basis at 22 (noting that all BACT determination relied, in part, on EKPC's BACT analysis). EKPC's analysis excluded coal washing as an effective add-on BACT mechanism based on adverse economic, environmental, and energy impacts. See Supplemental BACT Analysis at 8-9 (noting that coal washing cost $11,706 per ton SO_2 removed, would produce slurry ponds, and would lower pollutant removal efficiencies in the CFB). Thus, based on the information provided by KYDAQ and EKPC and the lack of information to the contrary from Petitioner, EPA does not find that the decision to exclude coal washing as an additional control mechanism for limiting SO_2 emissions brings this permit out of compliance with the CAA, including the PSD permitting requirements. *See Prairie State Generating Co.*, slip op. at 53-55 (finding that petitioners had failed to demonstrate clear error in the decision to reject coal washing in the BACT analysis when the analysis showed that any benefits of coal washing where outweighed by its cost, energy, and environmental impacts).

Petitioner's assertion that KYDAQ and EKPC were required to consider the feasibility of coal washing for all three coal types considered, and not just the design basis coal, is also misplaced. Having already determined earlier in the SO_2 BACT analysis that the other coal types could be excluded, KYDAQ and EKPC proceeded to determine whether the additional mechanism of coal washing could be combined with the remaining BACT option – the design basis coal – to further reduce SO_2 emissions.[14] *See Prairie State Generating Co.*, slip op. at 51-52

[14] While EPA acknowledges that the BACT determination with regard to coal selection is being remanded to KYDAQ as discussed above, this does not change the basic premise that coal washing is a supplemental control technology that can be considered after

(explaining why coal washing is an "additional" or "supplemental" control technology). Nothing in the PSD permitting requirements require that the possible emission reduction benefits of supplemental control technologies must be analyzed with regard to control options that have already been eliminated. Accordingly, Petitioner fails to demonstrate that the SO_2 limit contained in the permit for Unit 4 is not in compliance with the CAA. For these reasons, EPA denies the petition with respect to this issue.

3. Consideration of Integrated Gasification Combined Cycle (IGCC)

Petitioner's Comment: Petitioner argues that "[t]he Administrator must object to the permit because it contains limits that do not represent BACT," and explains that "[a] BACT analysis for a coal fired power plant must include consideration of Integrated Gasification Combined Cycle ("IGCC") technology." Petitioner emphasizes that "IGCC constitutes a cleaner production process and an innovative fuel combustion technique under the definition of BACT," and that "IGCC is a different process and combustion technique, which achieves much lower emission rates than the [circulating fluidized bed] process proposed for Spurlock 4." Petitioner argues that IGCC should be considered under the BACT analysis, and should not be considered to redefine the source, based on the definition of BACT under CAA section 169(3), the legislative history of that provision, and decisions of EPA's Environmental Appeals Board ("EAB" or "Board").

EPA's Response: EPA disagrees with Petitioner's conclusion. Petitioner has not sufficiently demonstrated to the Administrator that the permit limits, by not reflecting IGCC, do not represent BACT. As a result, Petitioner has not demonstrated that the permit fails to include applicable PSD requirements, and the petition is, therefore, denied with respect to this issue.

Petitioner made the same IGCC comment on the proposed permit as it now makes this petition. KYDAQ responded to the initial comment by stating: "IGCC would result in a redefinition of the basic design of the project and is not required under a BACT analysis ...." KYDAQ's Response to Comments at 44. [15]

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selection of the primary BACT fuel. Accordingly, the Administrator notes that if KYDAQ were to choose a different coal type as BACT following remand, KYDAQ should consider in its BACT analysis whether washing the different coal should be an additional SO_2 control technology for Spurlock Unit 4.

[15] KYDAQ added that "review of IGCC could be performed under [CAA] section 165(a)(2)," which requires the permitting authority to provide an opportunity for interested persons to comment on "alternatives" to the source. KYDAQ determined that "the Division will not require the use of an IGCC design as an alternative to a [circulating fluidized bed] unit," KYDAQ's Response to Comments at 44. Petitioners have not challenged the adequacy of this latter determination; and in denying this petition with respect to the IGCC issue, I am not making any determination regarding the adequacy of

In repeating, in their petition, the comments made on the proposed permit, Petitioners have not demonstrated that KYDAQ erred in declining to analyze IGCC under BACT on grounds that IGCC would redefine the source. The Administrator and the EAB have long maintained a policy against utilizing the BACT requirement as a means to fundamentally redefine the basic design or scope of a proposed project. *See e.g., In re Knauf Fiber Glass*, 8 E.A.D. 121, 140 (EAD 1998); *In the Matter of: Pennsauken County, New Jersey, Resource Recovery Facility*, 2 E.A.D. 667, 673 (Adm'r 1988) ("*Pennsauken County*"). EPA has not required applicants proposing to construct coal-fired steam electric generating facilities to evaluate building natural gas-fired combustion turbines as part of a BACT analysis, even though a gas turbine may be inherently less polluting. *In re SEI Birchwood Inc*, 5 E.A.D. 25 (1994); *In the Matter of: Old Dominion Electric Cooperative Clover, Virginia*, 3 E.A.D. 779, 793 n. 38 (Adm'r 1992). Likewise, in *In re Hawaii Commercial & Sugar Co.*, the EAB found no error by the permitting authority in rejecting the petitioner's argument that the BACT analysis for a coal-fired steam electric generator should include the option of constructing an oil-fired combustion turbine. 4 E.A.D. 95, 99-100 (EAB 1992).

EPA's policy reflects the Agency's longstanding judgment that limits should exist on the degree to which permitting authorities can dictate the design and scope of a proposed facility through the BACT analysis. This policy is based on a reasonable interpretation of sections 165 and 169(3) of the CAA, which the EAB recently reiterated and explained in *In re Prairie State Generating Company*, PSD Appeal No. 05-05 (Aug. 24, 2006). In the *Prairie State* case, involving a permit for an coal-fired electric generating station that was co-located and co-permitted with a new coal mine supplying fuel for the facility, the Board determined that it was consistent with EPA's historic policy and the CAA for the permitting authority in this case to decline to conduct a detailed BACT review of the option of using lower-sulfur coal from another location. Based on various provisions of the CAA, including language that requires the "proposed facility" to be "subject to" BACT, the Board concluded that "the statute contemplates that the permit issuer looks to how the permit applicant defines the proposed facility's purpose or basic design" as part of Step 1 of the top-down BACT analysis. *Prairie State*, slip op. at 28-29. The Board further explained that "the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility." *Prairie State,* slip op. at 30. The Seventh Circuit recently affirmed the EAB's *Prairie State* decision, including the Board's interpretation of the interplay between determining what redefines a source and the required BACT analysis. *See generally Sierra Club v. EPA,* slip op. (7th Cir. Aug. 24, 2007).

As discussed by the Board in the *Prairie State* opinion, affirmed by the Seventh Circuit, and explained more fully below, EPA's policy against redefining

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KYDAQ's alternatives analysis. *Cf. Sierra Club v. EPA,* slip op. at 3 (7th Cir. Aug. 24, 2007) (finding that only the BACT requirements were at issue because the petitioners had not invoked the alternatives provision).

the proposed source through the BACT analysis is supported by a permissible and reasonable interpretation of the Clean Air Act. The language in sections 165 and 169 of the CAA distinguishes between the consideration of alternatives to a proposed source on the one hand, and permitting and selection of BACT for the proposed source on the other. Alternatives to a proposed source are evaluated through the CAA section 165(a)(2) public hearing process, which requires that, before a permitting authority may issue a permit, interested persons have an opportunity to "submit written or oral presentations on the air quality impact of such source, *alternatives thereto*, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a)(2) (emphasis added). By listing "alternatives" and "control technology requirements" separately in section 165(a)(2), Congress distinguished "alternatives" to the proposed source that would wholly replace the proposed facility with a different type of facility, from the kinds of "production processes and available methods, systems and techniques" that are potentially applicable to a particular type of facility and should be considered in the BACT review. *See* 42 U.S.C. § 7479(3).[16]

In contrast to the requirements of section 165(a)(2), other parts of the PSD permitting process, including the requirement to apply BACT, focus on, and are generally confined by, the project as proposed by the applicant. Sections 165(a)(1) and 165(a)(4) of the CAA provide that no facility may be constructed unless "a permit has been issued for *such proposed facility* in accordance with this part" and "the *proposed facility* is *subject to* best available control technology for each pollutant subject to regulation under the Act." 42 U.S.C. § 7475(a)(1) and (a)(4) (emphasis added). The following definition of BACT in section 169(3) of the Act also makes clear that the BACT review is based on the proposed project, as opposed to something fundamentally different:

> an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a *case-by-case basis*, taking into account energy, environmental, and economic impacts and other costs determines is achievable for *such facility* through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant.

42 U.S.C. § 7479(3) (emphasis added). The phrases "proposed facility" and "such facility" in section 165(a)(4) and 169(3) refer to the specific facility proposed by the applicant, which has certain inherent design characteristics. The Act also requires BACT to be determined "on a case-by-case basis." The case-specific nature of the BACT analysis indicates that the particular characteristics of each facility are an important aspect of the BACT determination. Thus, the Act requires

[16] As noted above, KYDAQ considered, but rejected, IGCC as an "alternative[]," and Petitioner has not challenged that determination.

that permitting authorities determine BACT for each facility individually, considering the unique characteristics and design of each facility.

However, as the Petitioner has pointed out, the statutory definition of BACT also requires permitting authorities in selecting BACT to consider "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques." 42 U.S.C. § 7479(3). EPA has interpreted this phrase to require that permitting authorities evaluate both add-on pollution control technologies and lower polluting process in the BACT review. *Prairie State* at 33.

Considering these provisions together, the Act requires that the permitting authority conduct the BACT analysis on a "case-by-case" basis on the "proposed facility" while concurrently considering the "application of production processes and available methods, systems and techniques" that could alter the proposed facility. The statute does not provide clear direction on how the permitting authority is to reconcile these concepts and simultaneously consider the particulars of the facility proposed by the applicant while also assessing the use of methods or technology that could modify those particulars. Where a statute is ambiguous and Congress has not spoken to the precise issue, an administrative agency may formulate a policy to resolve the issue, provided that the policy is based on a permissible construction of the statute. *Chevron v. Natural Resources Defense Council*, 104 S.Ct. 2778, 2782 (1984). In this instance, sections 165 and 169(3) of the CAA are permissibly construed to authorize EPA and permitting authorities to establish some level of balance between the case-by-case nature of a BACT determination and the need to consider available processes, methods, systems, and techniques to reduce emissions. EPA's policy against redefining a source as part of the BACT analysis, which KYDAQ implemented for this permit, reasonably harmonizes the competing BACT obligations by requiring the permitting authority to consider potentially applicable processes, methods, systems, or techniques that may reduce pollution from the type of source proposed, provided such processes or techniques do not fundamentally redefine the basic design or scope of the facility proposed by the permit applicant.

EPA does not read the legislative history cited by the Petitioner to require a detailed evaluation of the IGCC technology in the BACT analysis for every proposed facility that generates electricity from coal. Petitioner points out that when Congress enacted the BACT definition in 1977, Senator Huddleston intended for the phrase "innovative fuel combustion techniques" to encompass "gasification" or "low Btu gasification,"[17] but this does not necessarily require EPA or other permitting authorities to identify the IGCC option as a candidate for further analysis at Step 1 of a top-down BACT review. The "innovative fuel combustion techniques" phrase appears in the BACT definition among a list of examples of things included in the phrase "production processes and available methods, systems, and techniques." Thus, the "innovative fuel combustion" language, like the phrase

[17] 123 Cong. Rec. S9434-35 (June 10, 1977) (debate on P.L. 95-95).

it modifies in the definition of BACT, is limited by other language discussed above that requires BACT to be applied to each proposed facility and determined on a case-by-case basis. Thus, even assuming that coal gasification was in all respects an innovative fuel combustion technique for producing electricity from coal, EPA does not interpret the CAA to require an "innovative fuel combustion technique" to be subject to a detailed BACT review when application of such a technique would re-design the proposed source to the point that it becomes an alternative type of facility, which, as discussed below, EPA believes would be the case if the IGCC technology were applied to Spurlock's Unit 4.

Furthermore, it is not clear from the terms of his statement that Senator Huddleston himself intended to require mandatory review of coal gasification in every case where such an option was not proposed by the permit applicant. Senator Huddleston said the purpose of the amendment was to leave no doubt that "all actions taken by the fuel user are to be taken into account." This phrase suggests the Senator wanted to make sure that, when a fuel user was proposing an innovative fuel combustion technique, such as coal gasification, that such actions by the fuel user would be taken into account and credited in the determination of BACT for the proposed facility. Thus, the Senator's statement could be read to express an intent similar to that expressed in a subsequent Congress when adding the phrase "clean fuels" to the definition of BACT in the 1990 amendments of the Clean Air Act. Pub. Law No. 101-549, § 403(d), 104 Stat. at 2631 (1990). At the time "clean fuels" was added to the list that includes "innovative fuel combustion techniques," the relevant Senate committee report stated the following in consecutive paragraphs:

> The Administrator may consider the use of clean fuels to meet BACT requirements if a permit applicant proposes to meet such requirements using clean fuel .... In no case is the Administrator compelled to require mandatory use of clean fuels by a permit applicant.

S. Rep. 101-228, at 338 (describing section 402(d) of S. 1630). Based on this legislative history, EPA does not interpret the list of examples that appear in the BACT definition after the phrase "production processes, methods, systems, or techniques" to require mandatory evaluation of each of those options at advanced stages of the BACT analysis, regardless of the degree to which such an option would redefine the type of facility proposed by the permit applicant.

Although EPA reads the Act to preclude redefining the source, EPA does not interpret the CAA to obligate a PSD permitting authority to accept all elements of a proposed project when determining BACT. To the contrary, EPA recognizes that the Act calls for an evaluation of the "application of production processes and available methods, systems, and techniques." 42 U.S.C. § 7479(3).

As the Board observed in *Prairie State*, EPA's policy against redefining the source is only relevant when considering lower polluting processes and would not

permit a reviewing authority to rule out "add-on controls" at Step 1 of the BACT analysis. Slip op. at 33. Further, although EPA does not require a source to consider a totally different design, some design changes to the proposed source are within the scope of the BACT review. *See Knauf Fiber Glass,* 8 E.A.D. 121, 136. As the Board observed in the *Prairie State* case, the central issue in situations involving a lower polluting process concerns "the proper demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not." Slip Op at 26. The Board observed that one of the permit issuer's tasks at Step 1 of the BACT analysis is to "discern which design elements are inherent to [the applicant's] purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility." *Prairie State*, slip op. at 30.

Since this line can be difficult to draw in each case, the Administrator and Environmental Appeals Board have generally recognized that the decision on whether to include a lower polluting process in the list of potentially-applicable control options compiled at Step 1 of the top-down BACT analysis is a matter within the discretion of the PSD permitting authority. *Knauf,* 8 E.A.D. at 136; *Old Dominion*, 3 E.A.D. at 793; *Hawaiian Commercial*, 4 E.A.D. at 100 and n.9. The Administrator and the EAB have usually respected the decisions of the permitting authority and only remanded permits in cases where it was clear that the permitting authority abused its discretion by excluding a particular option from consideration in the BACT review. *Knauf Fiber Glass,* 8 E.A.D. 121, 140; *See e.g., In the Matter of: Hibbing Taconite Company*, 2 E.A.D. 838, 843 (Adm'r 1989) ("*Hibbing*"). The Seventh Circuit affirmed this view in upholding the EAB's *Prairie State* decision, emphasizing the discretion given the permitting authority in making the technical judgment as to "where control technology ends and a redesign of the 'proposed facility' begins." *Sierra Club v. EPA,* slip op. at 5.

Petitioners insist that in *Pennsauken County,* the EAB made clear that the "'redefining the source' policy only prevents substituting a type of industrial category for another," and does not prevent substituting one type of source for another type of source in the same source category. Petitioners argue that the EAB affirmed this view in *Hibbing.* EPA does not read those two decisions in that manner. In particular, in *Hibbing*, the Board considered whether the option in question would "require any fundamental change to Hibbing's product, purpose, or equipment." Hibbing at 843 n. 12. Thus, in *Hibbing,* the EAB specifically identified a "fundamental change to ... equipment" as a type of redefinition of the source.

With respect to the project proposed by Spurlock, Petitioner's have not demonstrated that the KYDAQ erred in concluding that the application of the IGCC process to the facility would fundamentally change the nature of the proposed major source because it would fundamentally change the basic design of the equipment

that EKPC proposes to install at Spurlock. Specifically, EKPC has proposed a facility that fires coal in a fluidized mixture with limestone and inert materials, in a boiler to generate steam to drive an electric turbine. An IGCC facility uses a chemical process to first convert coal into a synthetic gas and to fire that gas in a combined cycle turbine. "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006. The combined cycle generation power block of an IGCC process employs the same turbine and heat recovery technology that is used to generate electricity with natural gas at other electric generation facilities. Thus, this portion of the IGCC process is very similar to existing power generation designs that EPA has agreed would redefine the basic design of the source when an applicant proposed to construct a pulverized coal-fired boiler. *In re SEI Birchwood Inc*, 5 E.A.D. 25 (1994); *Old Dominion Electric Cooperative Clover,* 3 E.A.D. 779. Furthermore, the core process of gasification at an IGCC facility is fundamentally different than a boiler. Coal gasification is more akin to technology employed in the refinery and chemical manufacturing industries than technologies generally in use in power generation (i.e. a controlled chemical reaction versus a true combustion process). Use of coal gasification technology would necessitate different types of expertise on the part of the applicant and employees to produce the desired product (electricity). Thus, these fundamental differences in equipment design are sufficient to conclude that the IGCC process would redefine the proposed source.

EPA acknowledges that in the *Prairie State* case, the EAB recognized that IGCC technology could be listed as a potentially applicable option at Step 1 of the BACT analysis, as Illinois EPA had elected to do in that case. However, the Board's opinion in *Prairie State* did not interpret the CAA to require IGCC to be listed as a potentially applicable control option at Step 1 for every permit application involving a coal-fired steam electric generating unit. That is, the Board did not conclude that IGCC, or any other option involving such extensive design changes, had to be listed as a potentially applicable option at Step 1 in each case or find that it would be an abuse of a permitting authority's discretion to decline to list IGCC at Step 1 of the BACT analysis for the type of facility proposed by Spurlock. The Board continued to recognize that the decision of where to draw the line between BACT options listed at Step 1 and alternatives to the proposed source is ultimately a matter within the discretion of the permitting authority. *Prairie State* slip op. at 29 n. 22.

Accordingly, I believe that the KYDAQ properly exercised its discretion in determining not to consider IGCC in the BACT analysis for Spurlock Unit 4, and Petitioner has not demonstrated that the title V permit fails to contain applicable requirements as a result. Accordingly, I deny the petition with respect to this issue.

4. Visible Emission Standard

Petitioner's Comment: The definition of BACT contained in the Kentucky SIP requires that a visible emission standard be included in each BACT limit for pollutants constituting visible emissions (i.e. PM/PM_{10} and SAM). Although a BACT limit for PM, PM_{10} or SAM typically includes an emissions rate limit, the Kentucky SIP requires BACT limits to include a visible emission standard.

EPA Response: In responding to Petitioner's claim concerning opacity for Unit 3, EPA expressed that BACT does not require an opacity limit. *See discussion* Section E.1., *supra*. Pursuant to 401 KAR 51:001(25), BACT is defined as "an emissions limitation, including a visible emission, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that ...." Petitioner asserts that the phrase "including a visible emission standard" requires a visible emission standard in each BACT limit for pollutants constituting visible emissions. Based on EPA's interpretation of similar regulatory language contained in 40 C.F.R. § 52.21(b)(12), it was reasonable for KDAQ to conclude that visible emissions may be part of a BACT emissions limit but are not a required element of BACT. This position is consistent with KYDAQ's Response to Comments at page 46, which states in part ... "opacity may be an indicator of particulate matter, fumes, gases or vapor, but is not an independent entity to be regulated. Opacity is the property for the absorption of light, an appropriate indicator for a variety of air pollution concerns, but not a regulated NSR pollutant."[18] Notwithstanding Petitioner's claim, the permit does contain an opacity limit of 20 percent. Further, PM/PM_{10} will also be monitored by PM CEMS which will provide a continuous method for ensuring compliance with the particulate emissions standard. For these stated reasons, EPA denies the petition with respect to this issue.

5. BACT Limit for Fine Particulate Matter ($PM_{2.5}$)

Petitioner's Comment: The permit must include a BACT limit for $PM_{2.5}$ emissions from Unit 4 because $PM_{2.5}$ is a regulated NSR pollutant. Further, EPA established a "national ambient air quality standard" (NAAQS) for $PM_{2.5}$, and the Kentucky SIP requires a BACT limit "for each regulated NSR pollutant for which the source has the potential to emit in significant amounts." 401 KAR 51:017.

EPA's Response: While EPA acknowledges that $PM_{2.5}$ is a regulated NSR pollutant, at this time EPA has not yet implemented NSR regulations for $PM_{2.5}$ NAAQS. It is well established that EPA has proposed the interim use of PM_{10} as a

[18] *See also* Illinois Environmental Protection Agency Bureau of Air, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application from Springfield City Water, Light and Power for Proposed Dallman Unit 4 at 39 (stating that "since opacity is not a pollutant, there is not a statutory obligation to set an opacity limit").

surrogate for $PM_{2.5}$ until NSR rules have been implemented. EPA has represented that:

> In view of the significant technical difficulties that now exist with respect to $PM_{2.5}$ monitoring, emissions, estimation, and modeling, EPA believes that PM_{10} may properly be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.
>
> When the technical difficulties are resolved, EPA will amend the PSD regulations under 40 C.F.R. §§ 51.166 and 52.21 to establish a $PM_{2.5}$ significant emissions rate and EPA will also promulgate other appropriate regulatory measures pertinent to $PM_{2.5}$, and its precursors.

Memorandum from John Seitz, Office of Air Quality Planning and Standards, "Interim Implementation of New Source Review Requirements for $PM_{2.5}$" (October 21, 1997).

This position was recently reaffirmed in specific guidance to the states:

> Using the surrogate $PM_{2.5}$ nonattainment major NSR program, States should assume that a major stationary source's PM_{10} emissions represent $PM_{2.5}$ emissions and regulate these emissions using either Appendix S or the States' SIP-approved nonattainment major NSR program.[19]

Memorandum from Stephen Page, Office of Air Quality and Planning and Standards (April 5, 2005). Thus, under the circumstances presented here, it was clearly appropriate for KYDAQ to use PM_{10} as a surrogate for $PM_{2.5}$. For these reasons, EPA denies the petition with respect to this issue.

6. PM Emissions from Unit 4 Cooling Tower

Petitioner's Comment: The source was required to consider as BACT for PM the use of a less polluting process, i.e., an air cooled condenser (ACC). KYDAQ unlawfully restricted its BACT analysis to the cooling design proposed by the facility.

[19] The terms of 40 C.F.R. § 52.24(k), Appendix S of Part 51 provide provisions for a transitional nonattainment major NSR program until EPA approves a State's Part D major NSR program into the SIP.

EPA's Response: EPA concurs with the position taken by KYDAQ regarding the appropriateness of the selected BACT for PM emissions from the cooling tower for Unit 4. In responding to the Petitioner, KYDAQ stated:

> Given that EKPC has chosen to build a facility employing a cooling tower as part of the process, a drift eliminator with a maximum drift rate of 0.0005 percent as included in the permit is BACT.

KYDAQ's Response to Comments at 49.

Petitioner asserts that the use of an ACC would be more appropriate because it is a less polluting process. However, Petitioner has failed to demonstrate that ACC technology is feasible at this source. BACT as defined by the CAA and Kentucky regulations allow for the use of a design standard rather than an emissions standard when technological limitations make imposition of an emission standard infeasible. As previously discussed, this interpretation has been confirmed by the Supreme Court and in numerous EAB decisions that took into consideration geographical differences and other constraints in determining that a given technology was not feasible for a particular source. *See Alaska Dept. of Environmental Conservation*, 540 U.S. 461, 488 (2004); *In re Cardinal FG, Co.*, PSD Appeal No. 04-04 slip op. at 11; and *In re Three Mountain Power*, 10 EAD 39 (EAB 2001). Such considerations are appropriate here, because the ACC technology advocated by the Petitioner is typically utilized in drier climate, particularly where the water supply is limited. In more humid climates, the technology is less effective and not as economically viable where water is less expensive. For these reasons, ACC is typically not considered a feasible technology for sources located in the southeast region of the United States, such as the Spurlock Station. *See Masonite Corp*, 5 EAD at 560 (noting that the permit issuer must have flexibility where "the technology itself or its application to the type of facility in question may be relatively unproven").

EPA previously determined that ACC was not the best technology available in its Clean Water Act § 316(b) rulemaking. 66 Fed. Reg. 65256, 65282 (Dec. 18, 2001). EPA estimated that the energy penalty of an ACC plant in a hot environment at peak summer conditions could be as much as 19.4 percent. Further, the cost of ACC is more than three times the cost of wet cooling after considering the costs for construction and operating costs. In light of the foregoing information, it is EPA's position that KYDAQ's BACT determination is reasonable for PM emissions from the cooling tower for Unit 4. For these reasons, EPA denies the petition with respect to this issue.

7. Monitoring and Reporting of PM Emissions from the Cooling Tower

Petitioner's Comments: Utilizing 0.0005 percent drift eliminators is not BACT for PM and it is not an enforceable emission limit. The permit must contain a BACT limit for PM/PM_{10}. PM/PM_{10} emissions result when drift from a cooling

tower evaporates and leaves mineral and other solids as suspended particulate matter in the air. An effective BACT limit must regulate all these factors or directly limit PM/PM_{10}. The permit does not require a correlation between these factors and PM/PM_{10}. Additionally, the permit requires only a one-time drift rate test rather than periodic tests. This is not sufficient to demonstrate continuous compliance with applicable limits.

EPA's Response: Contrary to Petitioner's assertion, the drift elimination rate limit of 0.0005 percent as BACT for the Unit 4 cooling tower is consistent with BACT determinations in several other recent coal-fired power plant permits. Recent examples of permits for coal-fired power plants with similar BACT limits for cooling towers include Longleaf Energy pulverized coal project in Georgia (0.001 percent); the Longview Energy pulverized coal project in West Virginia (0.002 percent); and the Prairie State Generation pulverized coal project in Illinois (0.0005 percent).

Further, Petitioner claims that the Spurlock permit provides insufficient monitoring provisions for emissions from the cooling tower is unsubstantiated. Specifically, the permit requires monthly monitoring of total dissolved solids (TDS) content of the circulating water and requires maintenance of records of the maximum pumping capacity and TDS content. Permit, Emissions Unit 23, Sections B.4 and 5. In addition, the permit requires the source to perform an initial performance test to assess the efficiency of the drift eliminators, as well as maintain the drift eliminators in accordance with the manufacturer's specifications. In making its claims, Petitioner provides no information to support the idea that the permit contains deficient monitoring for PM/PM_{10} and that periodic drift tests should be required. EPA finds that the permit contains sufficient monitoring, recordkeeping and performance test requirements for enforceability of the requirement to install a 0.0005 percent drift eliminator as a method of limiting PM emissions.

Finally, Petitioner's recommendation that a limit be placed on mineral and other solids that are suspended as particulate matter in the drift from the cooling tower is highly impractical, since EKPC has no direct control over the dissolved solids concentration in the Unit 4 emissions. Given the low drift elimination rate limit of 0.0005 percent established as BACT for the Unit 4 cooling tower, EPA does not believe that additional limits for PM_{10} emissions are necessary or practical.[20] For these reasons, EPA denies the petition with respect to this issue.

8. BACT Limit for Mercury and Beryllium

Petitioner's Comment: The Kentucky SIP, existing at the time the permit was issued, requires BACT limits for facilities that emit mercury in a "significant" amount. Although the Kentucky administrative regulations have recently been

[20] In light of this conclusion, Petitioner has not demonstrated that any failure to respond to comments on this issue resulted in, or may have resulted in, a flaw in the permit.

changed with respect to the level of mercury and beryllium emissions considered significant, the change has not yet been approved by EPA. Therefore, the existing Kentucky SIP controls and a BACT limit for mercury and beryllium is required. Additionally, because mercury is subject to a new source performance standard, a BACT limit for mercury must be established.

EPA's Comment: EPA has since approved Kentucky's revised SIP that changes the amount of mercury emissions that are considered "significant." 71 Fed. Reg. 38,990 (July 11, 2006). Since the mercury level referenced by Petitioner is obsolete and no longer applicable to the level of emissions generated at the Spurlock Station, this issue is moot. *See Glynn Environmental Coalition, Inc. v. EPA*, Docket No. 05-10375-GG (11 Cir. 2006) (dismissing petition as moot where sole issue was whether permit contained sufficient conditions to assure compliance with a rule that had since been removed from the Georgia SIP).

Petitioner also asserts that a BACT limit for mercury is required by the CAA because it is it is a regulated NSR pollutant under 401 KAR 51:001, which includes pollutants that are subject to any standard promulgated under 42 U.S.C. § 7411. However, CAA § 112(b), 42 U.S.C. § 7412(b) specifies that "the provisions of Part C (Prevention of Significant Deterioration) shall not apply to pollutants listed under this section." Mercury and beryllium compounds are listed in Section 112(b)(1) of the CAA. The CAA provides a note to Section 112(b)(1) explaining that " for all listings above which contain the word 'compound' ... the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substances that contains the named chemical ... as part of that chemical infrastructure." *See also* KYDAQ's Response to Comment at 73. Consequently, since both mercury and beryllium are listed HAPs regulated under Section 112, the PSD program requirements do not apply to these emissions. *See Newmont*, slip op. at 75-77 (concurring with Nevada Department of Environment that PSD provisions do not apply to mercury). For these reasons, EPA denies the petition with respect to this issue.

V. CONCLUSION

For the reasons set forth above, and pursuant to section 505(b)(2) of the Clean Air Act, I partially deny and partially grant the petition from the Sierra Club requesting that the Administrator object to the issuance of the title V permit for the Spurlock Station owned and operated by East Kentucky Power Cooperative, Inc.

Dated: AUG 3 0 2007

Stephen L. Johnson
Administrator

RESPONSE TO PUBLIC COMMENTS

ON

Draft
Air Pollution Control
Prevention of Significant Deterioration (PSD)
Permit to Construct

Permit No. PSD-OU-0002-04.00

<u>Permittee</u>:
Deseret Power Electric Cooperative
10714 South Jordan Gateway
South Jordan, Utah 84095

<u>Permitted Facility</u>:
110-Megawatt Waste Coal Fired Unit
at Bonanza Power Plant

United States Environmental Protection Agency
Region 8
Air & Radiation Program
Denver, Colorado
August 30, 2007

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A. INTRODUCTION

On April 14, 2004, Deseret Power submitted a Prevention of Significant Deterioration (PSD) permit application to the United States Environmental Protection Agency, Region 8 (EPA), to approve construction of a new coal-fired electric utility unit at Deseret's existing Bonanza power plant. The application was updated and re-submitted to EPA on November 1, 2004. Several amendments to the application were submitted over the following year and a half. The application, amendments, draft PSD permit, draft Statement of Basis, and all related correspondence between EPA and Deseret Power are contained in the Administrative Record of this permit action, which was made available for 30-day public comment in late June of 2006.

The existing Bonanza power plant is located in eastern Utah, on the Uintah & Ouray Indian Reservation, and consists of a single bituminous coal fired electric utility unit ("Unit 1"), rated at 500 megawatts electrical output. The fuel for Unit 1 is supplied by the Deserado coal mine, located about 35 miles east of the plant. Unit 1 was constructed in the early 1980's and is operating under a Federal PSD permit originally issued by EPA on February 4, 1981, then updated and re-issued on February 7, 2001.

The new unit at Bonanza plant would consist of a Circulating Fluidized Bed (CFB) boiler and associated equipment, rated at 110 megawatts electrical output, and designed to be fueled with waste coal from the Deserado mine. The PSD permit for the new unit is proposed to be issued as a separate permit from the PSD permit for Unit 1.

The EPA published a public notice in the following newspapers, on the following dates, soliciting comments on its proposal to issue the permit for the new unit, in accordance with Sections 160-169 of the Clean Air Act (CAA), 40 CFR 52.21, and 40 CFR part 124:

Uintah Basin Standard (Roosevelt, UT)	June 27, 2006
Vernal Express (Vernal, UT)	June 28, 2006
Grand Junction Sentinel (Grand Junction, CO)	June 28, 2006
Rio Blanco Herald Times (Meeker/ Rangely, CO)	June 29, 2006
Salt Lake Tribune (Salt Lake City, UT)	June 29, 2006

The public comment period ended on July 29, 2006.

On June 22, 2006, the EPA mailed copies of the draft PSD permit, draft Statement of Basis, public notice, and Administrative Record for the proposed permit action, consisting of all permit-related correspondence, to the following parties:

Uintah County Clerk's Office
147 East Main Street, Suite 2300
Vernal, Utah 84078

Ute Indian Tribe
Environmental Programs Office
6358 East Highway 40
Fort Duchesne, Utah 84026

EPA sent the documents to these locations specifically to have the documents available locally for public review, during the public comment period. As stated in the public notice, these documents were also available at the EPA office in Denver, Colorado, and on the internet through EPA's website, at:

http://www.epa.gov/region8/air, under the heading "Topics of Interest"

The draft PSD permit would require air pollutant emission controls and restrict emissions of the following pollutants at the CFB boiler and associated pollutant-emitting support equipment: total particulate matter, filterable particulate matter, sulfur dioxide, nitrogen oxide, carbon monoxide, and sulfuric acid.

During the public comment period, one comment letter and one comment e-mail were received by EPA that expressed concerns with the draft permit and/or Statement of Basis. The comment letter, received on July 28, 2006, was from a group of seven environmental organizations: Western Resource Advocates, Environmental Defense, Utah Chapter of the Sierra Club, Southern Utah Wilderness Alliance, Western Colorado Congress, Wasatch Clean Air Coalition, and HEAL Utah. Comments #1 through #11 below are from the letter. The comment e-mail, received on July 26, 2006, was from Kathy Van Dame, representing the Wasatch Clean Air Coalition. Comments #12 through #16 below are from the e-mail.

Comment letters supporting the proposed WCFU project were received from the mayors of seven Utah municipalities: Salem City, Spanish Fork, Provo, Manti City, St. George, Nephi and Levan. Since these letters did not express any concerns with the draft PSD permit, EPA does not consider a response necessary.

After the close of the public comment period, EPA received an e-mail dated April 24, 2007, from Katy Savage of Provo, Utah, expressing concern about pollutants that would be emitted from the WCFU project, and a a letter dated April 25, 2007, from Daniel D. McArthur, Mayor of the City of St. George, Utah, expressing concern about delay in issuing the EPA permit for the WCFU project.

A detailed description of the commenters' concerns, along with EPA's responses to the significant issues raised in the comments, is contained in Section B of this document. Some of the lengthier comments have been paraphrased or generalized to allow direct responses to the concerns raised.

All references in Section B to the "Statement of Basis" mean the draft Statement of Basis dated June 14, 2006, which was made available along with the draft PSD permit for public comment in late June of 2006. All references to the "WCFU" mean Deseret

Power's proposed Waste Coal Fired Unit at Bonanza power plant, the subject of this PSD permit action. All references to "EPA" mean the EPA Region 8 office in Denver, unless otherwise indicated.

Section C of this document describes the specific provisions of the draft permit and draft Statement of Basis that have been changed in the final permit decision as a result of public comment. The final permit and final Statement of Basis include some administrative changes that may not be described in Section C, including renumbering permit conditions due to additional conditions added to the final permit, renumbering sections of the Statement of Basis due to additional explanations added to the Statement of Basis, and rewording as necessary to reflect the fact that the permit and Statement of Basis are final, not draft.

Deseret Power requested meetings with EPA, and met with EPA, on October 16, 2006 and on May 7, 2007, and submitted additional written permit-related material after the close of the public comment period. EPA is including the additional material and a summary of the October 16, 2006 and May 7, 2007 meetings in the Administrative Record for EPA's final permit decision.

Documents upon which EPA relied in reaching the final permit decision, and as referenced in EPA's response to comments, such as the Statement of Basis, the PSD permit application, and supplemental documents, are contained in the Administrative Record. Copies of EPA's response-to-comments document, final permit, and final Statement of Basis, are available on EPA's website at:

http://www.epa.gov/region8/air, under the heading "Topics of Interest"

The website also provides a link to the Administrative Record.

Copies of the response-to-comments document, the final permit, and the final Statement of Basis are also available for public review at the same locations where the draft permit and Statement of Basis were available for review:

Uintah County Clerk's Office
147 East Main Street, Suite 2300
Vernal, Utah 84078

Ute Indian Tribe
Land Use Department
P.O. Box 460
6358 East Highway 40
Fort Duchesne, Utah 84026

All documents in the Administrative Record are available at the EPA office:

US EPA Region 8
Air & Radiation Program
1595 Wynkoop Street
Denver, CO 80202-1129
Contact: Mike Owens, 303-312-6440
owens.mike@epa.gov

B. COMMENTS AND RESPONSES

The descriptions of public comments below are a paraphrasing of the originally submitted comments. The full text of each public comment may be found in the Administrative Record for issuance of the WCFU permit, available at the same locations as the draft permit package was available (the Uintah County Clerk's office in Vernal, Utah, the Ute Indian Tribe office in Fort Duchesne, Utah, and the EPA Region 8 office in Denver, Colorado).

1. CARBON DIOXIDE/GREENHOUSE GAS EMISSIONS

Comment #1:

One group of commenters requested that EPA address carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions from the proposed Deseret Bonanza WCFU. The commenters stated that the Clean Air Act requires EPA to do so in two ways.

Comment #1.a. First, the commenters believe EPA has a legal obligation to regulate CO_2 and other GHGs under the Clean Air Act and thus should set CO_2 emission limits in this permit.

Comment #1.b. Second, the commenters believe that EPA should consider emissions of CO_2 in its BACT analyses for other pollutants at the Bonanza WCFU.

In support, the commenters cited a U.S. Supreme Court case that was pending at the time, an Environmental Appeals Board decision, a draft EPA guidance document, and an article presenting a potential legal rationale for using PSD permits to limit CO_2 emissions.

Response #1:

Response #1.a. Disagree. EPA recognizes the importance of addressing the global challenge of climate change, and in light of the Supreme Court's decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), the Agency is working diligently to develop an overall strategy for addressing the emissions of CO2 and other GHGs under the Clean Air Act. However, EPA does not currently have the authority to address the challenge of global climate change by imposing limitations on emissions of CO_2 and other greenhouse gases in PSD permits.

It is well established that "EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants." *North County Resource Recovery Assoc.*, 2 E.A.D. 229, 230 (EAB 1986). The Clean Air Act and EPA's regulations require PSD permits to contain emissions limitations for "each pollutant subject to regulation" under the Act. CAA § 165(a)(4); 40 C.F.R. § 52.21(b)(12). In defining those PSD permit requirements, EPA has historically interpreted the term "subject to regulation under the Act" to describe pollutants that are presently subject to a statutory or regulatory provision that requires actual control of

emissions of that pollutant. *See* 43 Fed. Reg. 26388, 26397 (June 19, 1978) (describing pollutants subject to BACT requirements); 61 Fed. Reg. 38250, 38309-10 (July 23, 1996) (listing pollutants subject to PSD review). In 2002, EPA codified this approach for implementing PSD by defining the term "regulated NSR pollutant" and clarifying that Best Available Control Technology is required "for each regulated NSR pollutant that [a major source] would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j)(2); 40 CFR 52.21(b)(50).

In defining a "regulated NSR pollutant," EPA identified such pollutants by referencing pollutants regulated in three principal program areas -- NAAQS pollutants, pollutants subject to a section 111 NSPS, and class I or II substance under title VI of the Act-- as well as any pollutant "that otherwise is subject to regulation under the Act." 40 CFR 52.21(b)(50)(i)-(iv). As used in this provision, EPA continues to interpret the phrase "subject to regulation under the Act" to refer to pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant. Because EPA has not established a NAAQS or NSPS for CO_2, classified CO_2 as a title VI substance, or otherwise regulated CO_2 under any other provision of the Act, CO_2 is not currently a "regulated NSR pollutant" as defined by EPA regulations.

Although the Supreme Court decided the case cited by commenters and held that CO_2 and other GHGs are air pollutants under the CAA, *see Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), that decision does not require the Agency to set CO_2 emission limits in the PSD permit for the Deseret Bonanza WCFU. Notably, the Court did not hold that EPA was required to regulate CO_2 and other GHG emissions under Section 202, or any other section, of the Clean Air Act. Rather, the Court concluded that these emissions were "air pollutants" under the Act, and, therefore, EPA could regulate them under Section 202 (the provision at issue in the *Massachusetts* case), subject to certain Agency determinations pertaining to mobile sources.

EPA is currently exploring options for addressing GHG emissions in response to the Supreme Court decision. EPA is taking the first steps toward regulating GHG emissions from mobile sources, but the Agency has not yet issued regulations requiring control of CO_2 emissions under the Act generally or the PSD program specifically. Accordingly, EPA cannot include emissions limitations for CO_2 (or other GHGs that are not otherwise regulated NSR pollutants) in the Deseret PSD permit because it has long been established that "EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants." *North County*, 2 E.A.D. at 230. At this time, we believe that any action EPA might consider taking with respect to regulation of CO_2 or other GHGs in PSD permits or other contexts should be addressed through notice and comment rulemaking, allowing for a process which is public and transparent and based on the best available science.

Response #1.b: Disagree. EPA recognizes the importance of addressing the global challenge of climate change, and in light of the Supreme Court's decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), the Agency is working diligently to develop an overall strategy for addressing the emissions of CO2 and other GHGs under the Clean Air Act. Nevertheless, with regard to the present permitting decision, the

record before the Agency does not suggest, and commenters have not provided any evidence showing, that the outcome of our BACT analysis for the regulated NSR pollutants emitted by the Deseret Bonanza WFCU would have been resulted in a different choice of control technologies had we considered the potential collateral environmental impacts of CO_2 emissions.

The CAA defines BACT as "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant." CAA § 169(3) (emphasis added); *see also* 40 CFR 52.21(b)(12). EPA has established a five-step, top-down process for determining BACT emission limits for each PSD-regulated pollutant considered in a permitting decision: (1) identify all potentially applicable control options (2) eliminate technically infeasible control options; (3) rank remaining technologies by control effectiveness; (4) eliminate control options from the top down based on energy, environmental, and economic impacts; and (5) select the most effective option not eliminated as BACT. *See Prairie State Generating Co.*, 13 E.A.D. ___, PSD Appeal No. 05-05, slip op. at 14-18 (EAB Aug. 24, 2006) (summarizing and describing steps in the top-down BACT analysis). *Accord Three Mountain Power, L.L.C.*, 10 E.A.D. 39, 42-43 n.3 (EAB 2001); *Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129-31 (EAB 1999); *Hawaii Electric Light Co.*, 8 E.A.D. 66, 84 (EAB 1998). Thus, EPA has traditionally considered the collateral impacts (energy, environmental, and economic) of each BACT option at Step 4 of this analysis.

The CAA does not specify how EPA should weigh these collateral impacts when determining BACT for a particular source. The Agency's longstanding interpretation is that "the primary purpose of the collateral impacts clause is to temper the stringency of the technology requirements whenever one or more of the specified collateral impacts – energy, environmental, and economic – renders use of the most effective technique inappropriate." *Columbia Gulf Transmission Co.*, 2 E.A.D. 824, 826 (EAB 1989). Accordingly, the environmental impacts analysis "is generally 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." *Old Dominion Electric Cooperative*, 3 E.A.D. 779, 792 (EAB 1992).

In this case, the commenters have not shown that consideration of the environmental impacts of CO_2 emissions in the collateral impacts step of the EPA's BACT analysis for the regulated NSR pollutants would lead to a different result in our selection of BACT for the Deseret facility. The record before the Agency does not suggest that the Agency should have selected a less stringent option as BACT in order to reduce the potential collateral environmental impacts of CO_2 emissions. Although there may be some differences in the CO_2 emissions resulting from use of the technologies we evaluated at step 4 of the BACT analysis, we do not have information indicating such

differences would be significant enough to necessitate changing our selection of BACT for other pollutants. *See Hillman Power Co., L.L.C.*, PSD Appeal Nos. 02-04 (July 31, 2002) ("collateral environmental impacts analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative."). Commenters have not given EPA cause to believe that comparisons of the CO_2 emissions from various control technologies considered in the BACT analysis for the Deseret Bonanza WCFU would render unacceptable any of the options we have identified as BACT for this PSD permit.

Specifically, the comments did not contain any information on CO_2 emissions that would lead EPA to reach a different conclusion in its BACT analysis for this facility. The commenters state only that "EPA must consider emissions of CO_2 in its BACT analysis for the Bonanza WCFU," but they do not address how the particular control technologies considered for the Bonanza WCFU would have resulted in substantially differing CO_2 emissions. Nor do they discuss how any such differences would have resulted in differing impacts that would have necessitated our selecting a different technology as BACT. Such comparisons are at the heart of the BACT analysis, and thus are required by a commenter alleging a deficiency in the analysis. *See Old Dominion*, 3 E.A.D. at 793 (finding no error based on petitioner's lack of "specificity and clarity" because they provided "no specific comparison" of differences in the environmental impacts of the various technologies considered in the BACT analysis). *See also Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc.*, 435 U.S. 519, 553 (U.S. 1978) (explaining that comments regarding an Agency's analysis of environmental impacts "cannot merely state that a particular mistake was made, …[but] must show why the mistake was of possible significance in the results"). Accordingly, commenters have failed to show how consideration of CO_2 emissions in the BACT environmental impacts analysis would have changed the Deseret Bonanza permitting decisions.

Moreover, because EPA has historically interpreted the phrase "environmental impacts" to focus on local environmental impacts that are directly attributable to the proposed facility, the collateral impacts analysis of this BACT determination is not the appropriate mechanism for addressing the potential global impacts of CO_2 emissions from the Deseret Bonanza WCFU. *See Columbia Gulf*, 2 E.A.D. at 829-30 (finding that the environmental impacts analysis "focuses on local impacts that constrain the source from using the most effective technology"). Any predicted impacts in the area surrounding the Deseret facility that are potentially due to global climate change – to which the CO_2 and other GHG emissions from the proposed source may contribute generally – are not the type of local environmental impact that is readily traceable directly back to the particular source subject to PSD review.

EPA's interpretation that the collateral environmental impacts analysis should focus on local impacts that are directly attributed to construction and operation of the proposed source is supported by relevant statutory language, legislative history, EAB decisions, and EPA policies and permitting decisions. Both the "case-by-case" language of the BACT definition and Congress' stated reason for adding the collateral impacts analysis to that definition suggest that a facility-centered, locally-focused analysis is

appropriate. *See Kawaihae Cogeneration Project*, 7 E.A.D. 107, 116-17 (EAB 1997) (describing how the collateral impacts analysis considers factors unique to the specific source); Senate Comm. on Environment And Public Works, A Legislative History of the Clean Air Act Amendments of 1977 (Comm. Print August 1978), vol. 6 at 4723-24 (explaining that the collateral impacts clause was added to provide permitting authorities with flexibility to consider the impact of a specific facility on the character of the community in which it was located). While the EAB's *North County* decision directed permitting authorities to look at the effect of emissions from non-PSD regulated hazardous air pollutants (i.e., HAPs) in the collateral impacts analysis, the Board's opinion did not specify that all emissions not directly regulated under PSD – such as CO_2 – had to be considered as well. *See id.*, 2 E.A.D. at 230 (stating that the "exact form" and "level" of the BACT environmental impacts analysis would depend on the facts of the individual permitting decision). In subsequent policy guidance, EPA did not interpret *North County* to call for consideration of global impacts, *see, e.g.*, Memorandum from Gerald Emison, OAQPS Director entitled *Implementation of North County PSD Remand*, pp. 3-4 (Sept. 22, 1987), and the EAB later determined that EPA did not have to consider CO_2 and other GHG emissions in the BACT environmental impacts analysis. *Interpower of New York*, 5 E.A.D. 130 (EAB 1994); *Kawaihae Cogeneration Project*, 7 E.A.D. 107 (EAB 1997). Consistent with these prior EAB decisions and Agency policy, EPA has not previously considered the environmental impact of CO_2 and other GHG emissions in setting the BACT levels for permits,[1] and for the reasons discussed above, we do not consider it necessary to do so in issuing the PSD permit for the Deseret Bonanza WFCU.

[1] Although one draft of EPA's 1990 *NSR Workshop Manual* referenced "greenhouse gas emissions" as an example of environmental impact that a reviewing authority might consider in the BACT analysis, EPA has not done so in practice. The Agency never finalized the draft guidance cited by commenters, and other drafts of that same document do not include the phrase "greenhouse gas emissions" as an example of the type of environmental impact to be considered in the BACT analysis. *See* http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/1990wman.pdf, at B49. Moreover, both of these drafts of the *NSR Workshop Manual* also indicate that the BACT environmental impacts analysis should focus on "consideration of site-specific circumstances," which contrasts with the notion that such analysis should be used to consider the source's impact on what is a global issue. *Id.* at B47.

2. INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

Comment #2:

One group of commenters asserted that the proposed permit did not adequately evaluate IGCC as an available method to lower air emissions in the BACT analysis. The group of commenters presented four arguments:

Comment #2.a. First, arguing that Federal law requires a thorough evaluation of IGCC as part of the BACT analysis.

Comment #2.b. Second, arguing that recent state actions requiring consideration of cleaner coal technology establish irrefutable precedence for the consideration of IGCC, and validate the commenters' position on the "plain language of the definition of BACT."

Comment #2.c. Third, alleging EPA Region 8 previously determined it was appropriate to evaluate IGCC in the BACT analysis for a CFB coal-fired power plant. Commenters cited EPA Region 8's April 6, 2004 letter to the Utah Division of Air Quality, on Utah's proposed PSD permit for Nevco Energy's Sevier Power Company Project. Commenters also cited EPA's April 28, 2004 request to Deseret Power to provide an explanation of why Deseret ruled out IGCC for the WCFU project.

Comment #2.d. Fourth, pointing out the overall benefit of the alternative IGCC technology, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, and increases in efficiency over other coal burning technologies.

Response #2:

Response #2.a. Disagree. EPA does not agree that the Clean Air Act requires a detailed evaluation of IGCC for the proposed facility, at or beyond step 1 of the top-down BACT analysis. We evaluated whether IGCC should be listed at step 1 and considered the commenters arguments, but we have not been persuaded to change our view that this alternative process would represent a redefinition of the source proposed by the applicant and thus need not be listed as a potentially applicable control option at step 1 and evaluated further in the BACT analysis for this type of facility. We have, however, evaluated this option as a potential alternative to the proposed source under other parts of our PSD permit review; see discussion below in response #2.d.

The Administrator and EPA's Environmental Appeals Board ("EAB" or "Board") have long maintained a policy against utilizing the BACT requirement as a means to fundamentally redefine the basic design or scope of a proposed project. *See, e.g., Knauf Fiber Glass, GMBH*, 8 E.A.D. 121, 140 (EAB 1998); *Pennsauken County, New Jersey, Resource Recovery Facility*, 2 E.A.D. 667, 673 (Adm'r 1988). EPA has not required applicants proposing to construct coal-fired steam electric generating facilities to evaluate building natural gas-fired combustion turbines as part of a BACT analysis, even though a

gas turbine may be inherently less polluting. *SEI Birchwood Inc*, 5 E.A.D. 25 (1994); *Old Dominion Electric Cooperative Clover, Virginia*, 3 E.A.D. 779, 793 n. 38 (Adm'r 1992). Likewise, in *Hawaii Commercial & Sugar Co.*, the EAB found no error by the permitting authority when the petitioner argued that the BACT analysis for a coal-fired steam electric generator should include the option of constructing an oil-fired combustion turbine. 4 E.A.D. 95, 99-100 (EAB 1992).

EPA's policy reflects the Agency's longstanding judgment that limits should exist on the degree to which permitting authorities can dictate the design and scope of a proposed facility through the BACT analysis. This policy is based on a reasonable interpretation of sections 165 and 169(3) of the CAA, which recognizes that, although the permitting authority must take comment on and may consider alternatives to a proposed facility, the BACT analysis itself is conducted without changing fundamental characteristics of the proposed source.

The EAB recently reiterated and explained EPA's policy against redefining the source through the BACT analysis in *Prairie State Generating Company*, PSD Appeal No. 05-05 (Aug. 24, 2006). In the Prairie State case, involving a permit for an coal-fired electric generating station that was co-located and co-permitted with a new coal mine supplying fuel for the facility, the Board determined that it was consistent with EPA's historic policy and the Clean Air Act for the permitting authority in this case to decline to conduct a detailed BACT review of the option of using lower-sulfur coal from another location. Based on various provisions of the Clean Air Act, including language that requires the "proposed facility" to be "subject to" BACT, the Board concluded that "the statute contemplates that the permit issuer looks to how the permit applicant defines the proposed facility's purpose or basic design" as part of Step 1 of the top-down BACT analysis. *Prairie State*, slip. op. at 28-29. The Board further explained that "the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility." *Prairie State* slip. op. at 30. The Seventh Circuit recently affirmed the EAB's *Prairie State* decision, including the Board's interpretation of the interplay of determining what redefines a source and the required BACT analysis. *See generally Sierra Club v. EPA*, slip op. (7th Cir. Aug. 24, 2007).

As discussed by the Board in the *Prairie State* opinion, affirmed by the Seventh Circuit, and explained more fully below, EPA's policy against redefining the proposed source through the BACT analysis is supported by a permissible and reasonable interpretation of the Clean Air Act. The language in sections 165 and 169 of the CAA distinguishes between the consideration of alternatives to a proposed source on the one hand and permitting and selection of BACT for the proposed source on the other. Alternatives to a proposed source are evaluated through the CAA section 165(a)(2) public hearing process, which requires that, before a permitting authority may issue a permit, interested persons have an opportunity to "submit written or oral presentations on the air quality impact of such source, *alternatives thereto*, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a)(2) (emphasis added). By listing "alternatives" and "control technology requirements" separately in section 165(a)(2),

Congress distinguished "alternatives" to the proposed source that would wholly replace the proposed facility with a different type of facility from the kinds of "production processes and available methods, systems and techniques" that are potentially applicable to a particular type of facility and should be considered in the BACT review. *See* 42 U.S.C. § 7479(3).

In contrast to the requirements of section 165(a)(2), other parts of the PSD permitting process, including the requirement to apply BACT, focus on, and are generally confined by, the project as proposed by the applicant. Sections 165(a)(1) and 165(a)(4) of the CAA provide that no facility may be constructed unless "a permit has been issued for *such proposed facility* in accordance with this part" and "the *proposed facility* is *subject to* best available control technology for each pollutant subject to regulation under the Act." 42 U.S.C. § 7475(a)(1) and (a)(4) (emphasis added). The following definition of BACT in section 169(3) of the Act also makes clear that the BACT review is based on the proposed project, as opposed to something fundamentally different:

> an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a *case-by-case basis*, taking into account energy, environmental, and economic impacts and other costs determines is achievable for *such facility* through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant.

42 U.S.C. § 7479(3) (emphasis added). The phrases "proposed facility" and "such facility" in section 165(a)(4) and 169(3) refer to the specific facility proposed by the applicant, which has certain inherent design characteristics. The Act also requires BACT to be determined "on a case-by-case basis." The case-specific nature of the BACT analysis indicates that the particular characteristics of each facility are an important aspect of the BACT determination. Thus, the Act requires that permitting authorities determine BACT for each facility individually, considering the unique characteristics and design of each facility.

As the group of commenters has also pointed out, the statutory definition of BACT also requires permitting authorities in selecting BACT to consider "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques." 42 U.S.C. §7479(3). EPA has interpreted this phrase to require that permitting authorities evaluate both add-on pollution control technologies and lower polluting process in the BACT review. *Prairie State* at 33.

Considering these provisions together, the Act requires that we conduct the BACT analysis on a "case-by-case" basis on the "proposed facility" while concurrently considering the "application of production processes and available methods, systems and

techniques" that could alter the proposed facility. The statute does not provide clear direction on how EPA is to reconcile these concepts and simultaneously consider the particulars of the facility proposed by the applicant while also assessing the use of methods or technology that could modify those particulars. Where a statute is ambiguous and Congress has not spoken to the precise issue, an administrative agency may formulate a policy to resolve the issue, provided that the policy is based on a permissible construction of the statute. *Chevron v. Natural Resources Defense Council*, 104 S.Ct. 2778, 2782 (1984). In this instance, sections 165 and 169(3) of the Clean Air Act are permissibly construed to authorize EPA and permitting authorities to establish some level of balance between the case-by-case nature of a BACT determination and the need to consider available processes, methods, systems, and techniques to reduce emissions. EPA's policy against redefining a source as part of the BACT analysis reasonably harmonizes the competing BACT obligations by requiring the permitting authority to consider potentially applicable processes, methods, systems, or techniques that may reduce pollution from the type of source proposed, provided such processes or techniques do not fundamentally redefine the basic design or scope of the facility proposed by the permit applicant.

EPA does not read the legislative history cited by the commenter to require a detailed evaluation of the IGCC technology in the BACT analysis for every proposed facility that generates electricity from coal. That Senator Huddleston intended for the phrase "innovative fuel combustion techniques" to encompass "gasification" or "low Btu gasification" does not necessarily require EPA or other permitting authorities to identify the IGCC option as a candidate for further analysis at step 1 of a top-down BACT review. The "innovative fuel combustion techniques" phrase appears in the BACT definition among a list of examples of things included in the phrase "production processes and available methods, systems, and techniques." Thus, the "innovative fuel combustion" language, like the phrase it modifies in the definition of BACT, is limited by other language discussed above that requires BACT to be applied to each proposed facility and determined on a case-by-case basis. Thus, even assuming that coal gasification was in all respects an innovative fuel combustion technique for producing electricity from coal, we do not interpret the Clean Air Act to require an "innovative fuel combustion technique" to be subject to a detailed BACT review when application of such a technique would re-design the proposed source to the point that it becomes an alternative type of facility, which, as discussed below, we believe would be the case if the IGCC technology were applied to Deseret's project.

Furthermore, it is not clear from the terms of his statement that Senator Huddleston himself intended to require mandatory review of coal gasification in every case where such an option was not proposed by the permit applicant. Senator Huddleston said the purpose of the amendment was to leave no doubt that "all actions taken by the fuel user are to be taken into account." This phrase suggests the Senator wanted to make sure that, when a fuel user was proposing an innovative fuel combustion technique, such as coal gasification, that such actions by the fuel user would be taken into account and credited in the determination of BACT for the proposed facility. Thus, the Senator's statement could be read to express an intent similar to that expressed in a

subsequent Congress when adding the phrase "clean fuels" to the definition of BACT in the 1990 amendments of the Clean Air Act. Pub. Law No. 101-549, § 403(d), 104 Stat. at 2631 (1990). At the time "clean fuels" was added to the list that includes "innovative fuel combustion techniques," the relevant Senate committee report stated the following in consecutive paragraphs:

> The Administrator may consider the use of clean fuels to meet BACT requirements if a permit applicant proposes to meet such requirements using clean fuel. . . . In no case is the Administrator compelled to require mandatory use of clean fuels by a permit applicant.

S. Rep. 101-228, at 338 (describing section 402(d) of S. 1630). Based on this legislative history, EPA does not interpret the list of examples that appear in the BACT definition after the phrase "production processes, methods, systems, or techniques" to require mandatory evaluation of each of those options at advanced stages of the BACT analysis, regardless of the degree to which such an option would redefine the type of facility proposed by the permit applicant.

Although EPA reads the Act to preclude redefining the source and to draw a distinction between alternatives to the proposed source and lower polluting process that can be applied to the proposed source, EPA does not interpret the Clean Air Act to obligate a PSD permitting authority to accept all elements of a proposed project when determining BACT. To the contrary, EPA recognizes that the Act calls for an evaluation of the "application of production processes and available methods, systems, and techniques." 42 U.S.C. §7479(3).

As the Board observed in *Prairie State*, EPA's policy against redefining the source is only relevant when considering lower polluting processes and would not permit a reviewing authority to rule out "add-on controls" at Step 1 of the BACT analysis. Slip. op. at 33. Further, although EPA does not require a source to consider a totally different design, some design changes to the proposed source are within the scope of the BACT review. *See Knauf Fiber Glass*, 8 E.A.D. at 136. As the Board observed in the *Prairie State* case, the central issue in situations involving a lower polluting process concerns "the proper demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not." Slip. Op. at 26. The Board observed that one of the permit issuer's tasks at step 1 of the BACT analysis is to "discern which design elements are inherent to [the applicant's] purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility." *Prairie State*, slip. op. at 30.

Since this line can be difficult to draw in each case, the Administrator and Environmental Appeals Board have generally recognized that the decision on whether to include a lower polluting process in the list of potentially-applicable control options compiled at Step 1 of the top-down BACT analysis is a matter within the discretion of the PSD permitting authority. *Knauf Fiber Glass*, 8 E.A.D. at 136; *Old Dominion*, 3 E.A.D.

at 793; *Hawaiian Commercial*, 4 E.A.D. at 100 & n.9. The Administrator and the EAB have usually respected the decisions of the permitting authority and only remanded permits in cases where it was clear that the permitting authority abused its discretion by excluding a particular option from consideration in the BACT review. *Knauf Fiber Glass*, 8 E.A.D. at 140. *See, e.g., Hibbing Taconite Company*, 2 E.A.D. 838, 843 (Adm'r 1989). The Seventh Circuit affirmed this view in upholding the EAB's *Prairie State* decision, emphasizing the discretion given the permitting authority in making the technical judgment as to "where control technology ends and a redesign of the 'proposed facility' begins." *Sierra Club v. EPA*, slip op. at 5.

In its review of this issue in *Hibbing*, the Board considered whether the option in question would "require any fundamental change to Hibbing's product, purpose, or equipment." *Hibbing* at 843 n. 12. In *Prairie State*, where the use of the alternative coal source arguably did not significantly affect the power-generating equipment to be used at the proposed source, the Board focused on the applicants "objective or purpose" to the extent that purpose was "articulated for reasons independent of air quality permitting." *Prairie State*, slip. op. at 30.

With respect to the project proposed by Deseret, our assessment is that the application of the IGCC process to the Deseret facility would fundamentally change the nature of the proposed major source. The IGCC option would both fundamentally change the basic design of the equipment that Deseret proposes to install and fundamentally alter the objective and purpose of Deseret to make productive use of a coal supply that was previously considered a waste. Thus, we consider the IGCC process to be an alternative to the proposed source that should be evaluated under section 165(a)(2) of the Clean Air Act rather than as a BACT candidate under section 165(a)(4).

From an equipment perspective, Deseret has proposed a facility that fires pulverized waste coal in a fluidized mixture with limestone and inert materials, in a boiler to generate steam to drive an electric turbine. An IGCC facility uses a chemical process to first convert coal into a synthetic gas and to fire that gas in a combined cycle turbine. "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006. The combined cycle generation power block of an IGCC process employs the same turbine and heat recovery technology that is used to generate electricity with natural gas at other electric generation facilities. Thus, this portion of the IGCC process is very similar to existing power generation designs that EPA has agreed would redefine the basic design of the source when an applicant proposed to construct a pulverized coal-fired boiler. *SEI Birchwood Inc*, 5 E.A.D. 25 (1994); *Old Dominion Electric Cooperative Clover, Virginia*, 3 E.A.D. 779 (Adm'r 1992). Furthermore, the core process of gasification at an IGCC facility is fundamentally different than a boiler. Coal gasification is more akin to technology employed in the refinery and chemical manufacturing industries than technologies generally in use in power generation (i.e. a controlled chemical reaction versus a true combustion process). Use of coal gasification technology would necessitate different types of expertise on the part of the applicant and employees to produce the desired product (electricity). Thus, these fundamental

differences in equipment design are sufficient to conclude that the IGCC process would redefine the proposed source. Similarly, in *Sierra Club v. EPA*, slip op. at 4 (7th Cir. Aug. 24, 2007), the Court upheld the EAB's decision that use of low-sulfur coal that was available only at a distance from a proposed plant would redefine the source, because the plant was designed to use higher sulfur coal located at a nearby mine. As the Court explained, "to convert the design from that of a mine-mouth plant to one that burned coal obtained from a distance would require that the plant undergo significant modifications – concretely, the half-mile-long conveyor belt, and its interface with the mine and the plant, would be superfluous and instead there would have to be a rail spur and factilities for unloading coal from rail cars and feeding it into the plant." *Id.*

Furthermore, Deseret Power's proposal calls for extracting the remaining heating value of the waste coal that has accumulated over the past 20 years in order to conserve other natural resources. In light of the technical difficulties of using IGCC for waste coal (described in detail below), IGCC would not serve the basic purpose of the project, which is to take advantage of the current waste coal reserves and future waste coal generated from the coal washing operations that provide the existing Bonanza Unit 1 with its coal. *See* Letter from Ed Thatcher, Deseret Power, to Richard R. Long, EPA Region 8, May 10, 2005. Thus, in addition to fundamentally changing the basic design of the source that Deseret proposes to construct, the IGCC option would also have the effect of regulating the applicant's objective or purpose for the proposed facility by precluding the use of the waste coal resource. The record reflects that Deseret is seeking to use waste coal for reasons independent of air quality permitting. See *Prairie State*, slip. op. at 30.

We acknowledge that in the *Prairie State* case, the EAB recognized that IGCC technology could be listed as a potentially applicable option at step 1 of the BACT analysis, as Illinois EPA had elected to do in that case. However, the Board's opinion in *Prairie State* did not interpret the Clean Air Act to require IGCC to be listed as a potentially applicable control option at step 1 for every permit application involving a coal-fired steam electric generating unit. In *Prairie State*, the Board did not directly address the issue raised by the Petitioners comment on the Deseret permit because Illinois EPA chose, in an exercise of its discretion, to list the IGCC option at step 1 of the BACT analysis for the proposed facility and further analyze the option. IEPA ultimately eliminated the option at step 2. *See Prairie State*, slip. op. at 45. In Prairie State, the Board pointed to IEPA's consideration of the IGCC option beyond step 1 to illustrate that there was no question that IEPA had conducted a sufficiently thorough step 1 BACT analysis in that case, because IEPA had even considered an option that "would have required extensive design changes to Prairie State's proposed facility." Slip. op. at 36. The Board did not conclude that IGCC, or any other option involving such extensive design changes, had to be listed as a potentially applicable option at Step 1 in each case or find that it would be an abuse of a permitting authorities discretion to decline to list IGCC at Step 1 of the BACT analysis for the type of facility proposed by Deseret. The Board continued to recognize that the decision of where to draw the line between BACT options listed at step 1 and alternatives to the proposed source is ultimately a matter within the discretion of the permitting authority. *Prairie State* slip. op. at 29 n. 22.

Moreover, even if EPA was to list IGCC as a potentially applicable option at step 1 of the BACT analysis for the facility proposed by Deseret, the IGCC option could also be eliminated at step 2 of the top-down BACT analysis for the facility proposed by Deseret. It is not technically feasible to use Deseret's waste coal in the IGCC process. Based on an analysis of samples, Deseret's waste coal has an average heating value of approximately 4,000 Btu/lb, with a range of 3,051 Btu/lb to 5,326 Btu/lb, and ash content of the waste coal is estimated by Deseret to be in excess of 50 percent by weight on a dry basis. *See* Statement of Basis at 9. As explained below, IGCC units are not designed to operate, nor have they been operated, with coal that has a heating value as low, or ash content as high, as the waste coal that will be utilized for the proposed project.

A recently issued EPA report on IGCC states that "relatively little research or commercial work has been done to investigate gasification of low rank coals, including subbituminous and lignite, for electric generation purposes. The existing IGCC plants use bituminous coal as feedstocks." *See* "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006, page ES-1, available in the Administrative Record for this permit and through website at:

http://www.epa.gov/air/caaac/coaltech/2007_01_epaigcc.pdf

The report only discusses IGCC units as a possibility for use with bituminous, subbituminous and lignite coals. Deseret's waste coal is a lower rank of coal than subbituminous or lignite, having much lower heat content and much higher ash content than either subbituminous or lignite.

The above-mentioned EPA report states that there are currently two commercial-scale, coal-based IGCC plants in the U.S. and two in Europe. The U.S. projects (Wabash River Repowering Project in Indiana and Tampa Electric Polk Power Station in Florida) were both supported by the DOE's Clean Coal Technology demonstration program. Both plants have operated on bituminous coals and petroleum cokes; no use of low-rank coal at these facilities is known. EPA report at 2-6 and 2-7.

Another publication on IGCC analyzes the impact that various coal parameters have on various gasifiers, based on actual operation of the gasifiers. *See* "Coal Quality Handbook for IGCC," published by Cooperative Research Centre for Coal in Sustainable Development, Technology Assessment Report 8, April 1999, available through website at http://www.ccsd.biz/products/qualitybook.cfm .

Page 14 of the Handbook lists the maximum ash content of the coal that can be handled by various types of gasifiers. For a moving bed gasifier, the ash content has to be less than 15 percent; for an entrained bed gasifier, less than 25 percent; and for a fluidized bed gasifier, less than 40 percent. As mentioned above, Deseret's waste coal will have ash content in excess of 50 percent.

In addition to the Wabash River and Tampa Electric IGCC projects, the above-mentioned Handbook reviews several other IGCC demonstration or pilot projects, utilizing various gasifier designs, and the required characteristics of the coal. These projects include:

BGL IGCC Process, owned/operated by British Gas and Lurgi
Demkolec IGCC plant, owned/operated by Shell
Nedo facility, owned/operated by Engineering Research Associates
Pinon Pine Power Project, owned/operated by Sierra Pacific and MK Kellogg
Prenflow IGCC Process, owned/operated by Krupp Koppers and Siemens AG

However, all of these projects require coal with higher heat content and lower ash content than Deseret's waste coal. Of particular significance is that all of these projects (as well as the Wabash River and Tampa Electric projects) require coal with ash content less than 25 percent by weight on a dry basis. This is less than half the ash content of Deseret's waste coal. The Handbook also indicates that the above-mentioned IGCC projects generally require coal with much higher heat content than Deseret's waste coal, 8,100 to 13,760 Btu/lb, compared to Deseret's range of 3,051 to 5,326 Btu/lb, respectively. *See* Handbook at 22-28.

Inquiries with representatives of IGCC test programs confirmed that IGCC units have not been tested on coal with heat content as low as Deseret's waste coal. The U.S. Department of Energy's Power Systems Development Facility near Wilsonville, Alabama, has only utilized coal as low as 6,000 to 7,000 Btu/lb. The National Energy Technology Institute is also not aware of any IGCC unit utilizing coal with the low heating value that will be used in Deseret Power's proposed WCFU. (Ref: June 9, 2004 letter from Ed Thatcher, Deseret Power, to Richard R. Long, EPA Region 8.)

Response #2.b: Disagree. As was recognized by commenters in the comment letter, state decisions as to how to conduct the BACT analysis do not necessarily set the bar for EPA. As discussed above, the decision of where to draw the line between alternatives to the proposed source is a discretionary matter. The fact that some states have elected to list IGCC at step 1 of the BACT analysis for a coal-fired steam electric generating facility does not require EPA to do so if EPA's reasoned assessment is that the option would redefine the proposed source. EPA does not interpret the Clean Air Act to mandate evaluation of IGCC in a BACT analysis in cases involving proposed coal-fired steam electric generating facilities. We do not read the state examples cited by commenters to be based on a contrary interpretation of the Clean Air Act, but rather to reflect policy decisions in those states to conduct a more extensive analysis. Even if a state were to conclude that evaluation of IGCC was mandatory under its interpretation of the Clean Air Act or state law, such a decision by a state is not binding on EPA. Furthermore, because Illinois administers the Federal PSD program under a delegation agreement with EPA Region V, Illinois must act in a manner consistent with EPA's interpretation of the Clean Air Act and controlling regulations.

Response #2.c: Disagree. Regarding EPA's letter to Utah on Nevco, the commenters incorrectly characterized the letter as a determination on evaluating IGCC. Letters from EPA to states providing comments on proposed state PSD permits are not final EPA actions. *See Public Service Co. of Colorado v. Environmental Protection Agency, 225 F 3d 1144 (10th Cir.2000).*

Regarding EPA's request to Deseret Power to provide information regarding IGCC as an alternative to its planned CFB boiler, EPA's correspondence with Deseret merely explored IGCC as a possibility and made no final determination regarding IGCC. (Ref: Letters from Richard R. Long, EPA Region 8, to Ed Thatcher, Deseret Power, dated November 22, 2004, December 29, 2004, and June 22, 2005.)

Response #2.d. Partially agree. Since EPA's judgment is that use of the IGCC process would redefine the proposed source and thus need not be listed as an option at Step 1 of the BACT analysis for the Deseret facility, EPA is treating this comment as a request that EPA consider IGCC technology as an alternative to the proposed source in accordance with section 165(a)(2). EPA agrees with commenters that IGCC technology has many potential environmental benefits, but EPA is not requiring Deseret to employ this alternative technology for the reasons set forth below.

Under CAA section 165(a)(2), a PSD permit may not be issued unless, among other things, "a public hearing has been held with opportunity for interested persons … to appear and submit written or oral presentations on the air quality impact of such source, alternative thereto, control technology requirements, and other appropriate considerations…." EPA interprets section 165(a)(2) of the CAA to require that EPA consider and provide a reasoned response to comments identifying alternatives to the proposed source. *Prairie State*, slip op. at 38-41.

As EPA has observed in other contexts, EPA considers IGCC to be one of the most promising alternative technologies in reducing the environmental consequence of generating electricity. *See* "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006, at Forward. EPA has undertaken several initiatives to provide incentives for development and deployment of this technology. This approach is consistent with U.S. policy reflected in the Energy Policy Act of 2005, which established loan guarantees and tax incentives to encourage, but not require, development of IGCC facilities.

As a general matter, assessing whether IGCC is an appropriate alternative may entail a robust analysis of a broad range of factors. Such an analysis is not necessary in this case because there are two specific features of this plant that make IGCC a technically unfeasible option: fuel and plant size. The main fuel for this plant is waste coal, which has an ash content ranging from 40 to 56% and a heating value ranging from 3,000 to 5,400 Btu/lb. There exists no IGCC operating experience with this type of coal. An ash content as high as found in this waste coal would be a major issue for the design and operation of a gasifier (an integral part of an IGCC plant). In addition, the proposed

110 MW size for this plant is too small to be considered viable for an IGCC application. The four operating IGCC installations in the world (two of which are in the U.S.) are each greater than 250 MW in size. In general, the currently proposed IGCC plants by the U.S. power industry are larger than these operating IGCC installations. These plants are being proposed in larger size because they would be relatively less expensive per MW of electricity generation. Thus, even if it were possible to build a 110 MW IGCC plant, it would most likely be too costly to be considered economically viable.

More broadly, EPA believes the environmental and energy security goals of the United States are best served by encouraging the development of all forms of clean coal technology and the development of alternative fuels. Further, providing a reliable and secure supply of electricity to meet growing demand in the United States without adverse affects on air quality will require the use of a diverse array of power producing technologies and innovations in pollution control technology for each type of generating unit. Deseret's proposal to utilize a previously untapped reserve of waste coal with the best pollution control technology available for this type of source is consistent with these goals. In summary, comment #2 has not resulted in any changes to the permit.

3. SUPERCRITICAL CFB BOILER

Comment #3:

One group of commenters asserted that EPA should have required consideration of a supercritical CFB boiler in the BACT analysis for the Bonanza WCFU. Commenters cited discussion in a Western Governors Association Technology Working Group report on advanced clean coal technologies.

Response #3:

Agree. In response to this comment, EPA has evaluated a supercritical CFB boiler as a BACT option and has determined that since there are no known supercritical pressure turbines available in the size needed for the WCFU project, this option should be eliminated at step two of the top-down BACT analysis as technically infeasible, because it is not available and applicable for the WCFU project. *See In re Prairie State Generating Co.,* PSD Appeal No. 05-05, slip op. at 14-18 (EAB Aug. 24, 2006) (summarizing and describing steps in the top-down BACT analysis). *Accord In re Three Mountain Power, L.L.C.,* 10 E.A.D. 39, 42-43 n.3 (EAB 2001); *In re Knauf Fiber Glass, GmbH,* 8 E.A.D. 121, 129-31 (EAB 1999); *In re Hawaii Electric Light Co.,* 8 E.A.D. 66, 84 (EAB 1998).

At the first step of the top-down BACT analysis, all demonstrated and potentially applicable control technology alternatives must be identified. This must include a survey of production processes or innovative technologies that have a practical potential for application to reduce relevant emissions at the source type being evaluated. (*Prairie State*, slip op. at 17.) At the second step, "technically infeasible" options are eliminated. A technology is feasible if either it is demonstrated, i.e. installed and operated

successfully at a similar facility, or it is both "available" and "applicable." *Id.* A technology is considered "available" if it can be obtained by the applicant through commercial channels. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. If a technology is not demonstrated, or is found to be unavailable or not applicable, that technology will be eliminated from BACT consideration as technically infeasible. (*Three Mountain Power*, 10 E.A.D. at 42-43 n.3.)

As described by Babcock & Wilcox, a major boiler supplier, a supercritical boiler (regardless of combustion process, i.e. PC-fired, CFB, gas-fired, etc.) is designed to operate with the working medium, i.e. water, at a pressure above the critical point (3200 psia). At this pressure the medium cannot be separated to liquid and steam thus natural circulation is impossible, and the fluid is pumped through all heat absorbing tubes (called "Once-Through" in the boiler industry, versus natural circulation that the sub-critical pressure WCFU boiler is based on). (Ref: e-mails and attachments from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, November 6, 2006.)

The use of supercritical pressure in a power plant affects the design of all components within the plant cycle, boiler, turbine, pumps, etc. The steam cycle is based on available turbine designs. The boiler and other equipment are designed to meet the steam cycle defined by the turbine. This technology is being deployed currently at pulverized coal utility boilers. As such, EPA agrees with commenters that it is appropriate to consider supercritical technology, as a technology transfer control option under step one of the top-down BACT analysis.

However, according to Babcock & Wilcox and Foster-Wheeler, two major boiler suppliers, supercritical pressure steam turbines are not available in the size needed for the WCFU project. The smallest supercritical pressure turbine currently known to be available is three to four times larger than is needed for the WCFU project, which will operate at approximately 1,500 psia and is thus based on a sub-critical steam cycle. (Ref: e-mails and attachments from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, November 6, 2006 and November 13, 2006.)

In addition, the following information was provided by Siemens Power Systems to Deseret Power (forwarded to EPA Region 8 via e-mail from Deseret Power on November 13, 2006):

> *"To our knowledge, no manufacturer offers supercritical steam turbines in 110-120 MW range. The reason is that you would be unlikely to see any significant performance improvements for units that small. Key reasons are as follows:*
>
> *1. When you go to supercritical steam conditions the specific volume of the steam is reduced because of the higher pressure. That means the blades in the HP section have to be shorter. A major source of inefficiency in steam turbines is due to "flow disruptions" at the top and bottom of the blade where the moving flow meets the stationary rotor or casing. As the blades get shorter the impact of this "end wall" condition increases which in turn increases the flow losses.*

2. The supercritical conditions require a once-through boiler which requires a more powerful feed pump drive (higher pressures). That decreases plant efficiency and if you can't make that difference up with improved cycle performance, supercritical makes no sense.

We generally don't see units less than about 500 MW being built as supercritical because the performance improvement isn't significant and the unit is more expensive than subcritical."

The Western Governors Association report (cited by commenters) states that "no supercritical CFB combustion units have been demonstrated on a commercial scale." (Ref: Western Governors Association Technology Working Group's report on advanced clean coal technologies, second page of section titled "Advanced Clean Coal Technology Descriptions." The report is included in materials provided by Deseret Power to EPA via e-mail of November 6, 2006. Those materials are included in the Administrative Record for issuance of the WCFU permit.) EPA is aware of only one supercritical CFB boiler that has been proposed, designed and/or constructed anywhere in the world. As of January 11, 2006, design of that unit had not yet been completed. The unit is being designed for Poland's Poludniowy Koncern Energetyczny (PKE) for installation at its power plant at Lagisza in southern Poland. The proposed unit will have an output of 460 MW (four times larger than Deseret Power's proposed WCFU) and is being designed to fire bituminous coal. It is currently scheduled to begin operation in 2009. (Ref: Foster-Wheeler press release, January 11, 2006. The press release is included in materials provided by Deseret Power to EPA via e-mail of November 6, 2006. Those materials are included in the Administrative Record for issuance of the WCFU permit.)

Supercritical CFB boilers, while potentially applicable as a BACT option, are not a "demonstrated" technology under the BACT analysis, as the only such boiler EPA is aware of (the PKE boiler planned in Poland) has not been installed and operated successfully. Further, the technology is not "available" under the BACT analysis since, as explained above, it is not commercially available for CFB boilers, and supercritical pressure steam turbines are not available in the size needed for the WCFU project. Therefore, this technology is eliminated at step two of the top-down BACT analysis because it is undemonstrated and is not available.

The Environmental Appeals Board (EAB) has considered the question of whether certain technologies are available. The EAB has stated that "[i]f the technology is not available, the permit applicant is under no duty to consider it in the BACT analysis." *In re Pennsauken County, New Jersey, Resource Recovery Facility*, 2 E.A.D. 667, 671-672 (Nov. 10, 1988). The EAB has recognized that "[t]he question of availability for purposes of BACT is a practical, fact determination, using conventional notions of whether the technology can be put into use." *Id.* See also, *In re Maui Electric*, 8 E.A.D. 1, 13-16 (Sept. 10, 1998). EPA has evaluated a supercritical CFB boiler as a BACT option for Deseret Power's WCFU project and has found that there are no supercritical pressure turbines available in the size needed for the project. Therefore, EPA has

concluded that a supercritical CFB boiler is technically infeasible for this project and has eliminated it at step two of the BACT analysis.

In summary, comment #3 has not resulted in any change to the permit; however, the Statement of Basis has been changed, to add an explanation of why a supercritical CFB boiler was eliminated as a BACT control option at step two of the BACT analysis. Since BACT determinations are case-by-case, EPA's determination regarding a supercritical CFB boiler for the WCFU project should not be construed as a statement about what the determination should be for other projects.

4. PROPOSED BEST AVAILABLE CONTROL TECHNOLOGY (BACT) EMISSION LIMITS

4.a -- Cleaner coals:

Comment #4.a: One group of commenters alleged that EPA's analysis of cleaner coals as a BACT option was inadequate. The commenters indicated that while EPA did provide a cost analysis of using all "run-of-mine" coal from the Deserado mine and the resultant additional pollutant reductions (draft Statement of Basis at 24-28), EPA did not provide a comparison of the cost of using "run-of-mine" coal, either in part or wholly, compared to the cost other coal-fired electric utility CFB boilers in the region are paying for coal.

Commenters further alleged that EPA did not provide any comparative cost analysis for use of coal from other mines in the region, either wholly or in part as a blend with the Deserado waste coal. Commenters argued that such analyses are necessary to give context to this evaluation (e.g., *In re Inter-Power of New York. Inc.*, PSD Appeal Nos. 92-8 and 92-9, Decided March 16, 1994), arguing that in determining whether the cost of a control technology is reasonable, the cost must be compared to what other similar sources have had to bear.

As an example, commenters argued that EPA should have provided a comparison to the recently permitted Sevier Power Company's CFB power plant to be located in Sigurd, Utah. That facility will be burning a higher quality bituminous coal than the waste coal proposed for the Bonanza WCFU, and will be subject to lower permit emission limits than the WCFU for SO_2, total PM/PM_{10}, carbon monoxide and sulfuric acid.

Commenters alleged that EPA must analyze and provide data on the cost and quality of coal that the Sevier Power Company and other recently proposed power plants in the region are required to incur before it can determine that the cost of using "run-of-mine" fuel from the Deserado mine – either wholly or in part – is unreasonable. The commenters also suggested that EPA provide a similar analysis for using other higher quality coal available in the region, either wholly or as a blend with the waste coal.

Response #4.a:

Partially agree. As described below, EPA has supplemented the analysis of alternative coals in the Statement of Basis, to: (1) explain more fully, in terms of cost per ton of additional pollutant removed from the atmosphere, why use of coal from any mine in the region other than the Deserado mine, rather than waste coal from the Deserado mine, would be cost-prohibitive as a BACT option, and (2) explain why the BACT option of using ROM coal from the Deserado mine, as well as the BACT option of using coal from any other mine in the region, is cost-prohibitive when compared to the cost of BACT that other similar sources have to bear.

In presenting the analysis for alternative coal from another mine in the region as a BACT option, EPA is not taking a position on whether the use of a coal supply other than the one proposed by the applicant must be evaluated in the BACT analysis for the WCFU or similarly situated facilities. After EPA issued the draft permit for the WCFU, the EPA Environmental Appeals Board issued its opinion in *In re: Prairie State Generating Company*, PSD Appeal No. 05-05 (Aug. 24, 2006). This opinion established that there may be circumstances under which the permitting authority has the discretion not to list alternative coal supplies as an option at Step 1 of the BACT analysis, because such an option could fundamentally redefine the source.

However, we need not address whether this permit presents a similar circumstance, since the draft Statement of Basis included the use of a cleaner coal as an option and evaluated the economic impact of requiring the applicant to use exclusively mined coal from the Deserado mine rather than waste coal, or alternatively, exclusively mined coal from other mines rather than waste coal. (Draft Statement of Basis at pages 25-29.) Since EPA already started down this path of looking at other coal supplies for this permitted project, EPA has supplemented its analysis to further illustrate why it is appropriate to eliminate this option for this permit. Specifically, as described below, EPA is supplementing its BACT analysis in section VI.D.2 of the Statement of Basis, "Alternative coal from other mines," using a cost methodology in terms of dollars per ton of additional pollutant removed, similar to the cost methodology used in section VI.D.1, "Alternative coal from Deserado mine."

The first step in the alternative coal analysis is to determine what the alternative coal would cost, per ton of coal delivered. EPA asked Deseret Power to provide an estimate of what the total cost would be, per ton of coal delivered, to have coal supplied to the WCFU from mines in the region other than the Deserado mine. EPA asked that the estimate be for the least total cost scenario of the various other mines that could potentially supply coal. EPA further asked for a breakdown of mine-mouth ("Free-On-Board") cost plus transportation cost. (Ref: November 14, 2006 e-mail from Mike Owens, EPA Region 8, to Ed Thatcher, Deseret Power, included in the Administrative Record for issuance of the WCFU permit.)

Deseret Power responded that its letter to EPA dated May 10, 2005, at page 5, provided a cost estimate for coal purchased on the open market and delivered to the WCFU unit. The estimated cost for the coal at that time was $40 to $45 per ton delivered, which included the estimated delivery charge of $15 per ton. The FOB mine cost for the coal was estimated to be $25 to $30 per ton at that time. According to the November 13, 2006 issue of Coal Outlook (copy attached to Deseret Power's November 15, 2006 e-mail), the FOB mine cost for coal in Utah has increased to $37.75 per ton for current purchases of coal.

As mentioned in the draft Statement of Basis, the Bonanza plant is approximately 75 miles from the nearest rail transportation and approximately 100 miles by truck from the nearest alternative source of coal. The cost to construct a rail line to connect to the interstate rail system has been estimated by Deseret Power to exceed $300 million. (EPA has eliminated this option as too expensive.) The cost to truck the coal from the nearest

alternative coal source (i.e., other than the Deserado mine) was estimated by Deseret Power to be at least $15/ton. (Ref: Sept. 13, 2005 letter from Deseret Power to EPA, page 3, footnote 1, included in Administrative Record for issuance of the WCFU permit.)

In more recent correspondence to EPA, Deseret Power stated that it believes the delivery cost to haul the coal from the nearest alternative mines to the Bonanza plant site would still be about $15 per ton. Therefore, the current delivered cost would be $37.75 plus $15.00, or about $52.75 per ton delivered. (Ref: November 15, 2006 e-mail from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, included in the Administrative Record for issuance of the WCFU permit.) Being the cost from the nearest alternative mines, this 'cheapest delivered' cost is a conservative estimate, i.e., yielding the lowest calculated BACT cost to switch to coal from a mine other than the Deserado mine.

The next step in the analysis is to determine the annual cost of switching from Deserado waste coal to alternative coal from another mine. This requires a determination of how much alternative coal is necessary to achieve the equivalent annual boiler heat output as combustion of 1.2 million tons of waste coal per year, which is Deseret Power's projected waste coal usage rate. To make this determination, it is necessary to know the estimated heat content of the alternative coal. The CFB boiler project cited by commenters, Sevier Power Company, would use coal with an estimated heat content range of 10,200 to 12,000 Btu/lb, with average heat content of 11,390 Btu/lb. (Ref: "New Source Plan Review" by Utah Division of Air Quality, dated December 23, 2003, for the Sevier Power Company project, page 13, Table I-2, available online at http://www.airquality.utah.gov/Permits/PmtPowerPlants.htm.)

Rather than rely just on the Sevier project cited by commenters for an estimate of heat content of available coals in the region, EPA also examined a recent Utah Geological Survey (UGS) report, which lists heat content of coal at Utah mines ranging from 11,243 Btu/lb to 13,052 Btu/lb. (Ref: "Annual Review and Forecast of Utah Coal, Production and Distribution - 2005," published August 2006 by Utah Geological Survey, Open-File Report 481, Table A8: "Average Coal Quality at Utah Mines, 2005." Report available online at http://ugs.utah.gov/online/ofr.ofr-481.pdf.) For the sake of this analysis, EPA will use the upper end of this range (13,052 Btu/lb) as a conservative assumption, i.e., yielding the lowest calculated BACT cost to switch to alternative coal.

Since Deseret Power's waste coal has an average heat content of about 4,000 Btu/lb, EPA calculates that it would require about 367,760 tons per year of alternative coal rated at 13,052 Btu/lb heat content, to achieve the equivalent annual WCFU boiler heat output as combustion of 1.2 million tons per year of waste coal. The coal purchase cost of the alternative coal would therefore be:

$52.75/ton x 367,760 tons/year = $19,400,000/year.

EPA stated in the draft Statement of Basis that the cost of waste coal would be about $5 per ton delivered. The annual cost of using the waste coal would be:

$5/ton x 1,200,000 tons/year = $6,000,000/year.

(Note: The draft Statement of Basis indicated $5/ton x 1,200,000 tons/year = $3,405,000. This was an inadvertent mathematical error.) The incremental cost to use entirely alternative coal from another mine in the region, rather than waste coal, would therefore be the difference in cost of the two coals, which is $13,400,000/year.

The next step in the analysis is to determine the potential annual emission reductions that could be achieved by switching from waste coal to alternative coal from another mine. In the draft Statement of Basis, EPA presented its calculation of the reductions that could be achieved for each PSD pollutant, if emissions are reduced from the proposed WCFU permit allowables down to the lowest BACT determination EPA is aware of anywhere for a CFB boiler project (including the Sevier Power Company project cited by commenters). For condensible PM, EPA has since revised its estimate of lowest achievable emission rate down to 0.005 lb/MMBtu, to correspond to the condensible portion of the BACT emission limit for total PM/PM_{10} in the Utah permit for the Sevier Power Company project.

Potential Emission Reductions Due to a Switch From Waste Coal to Alternative Coal from Another Mine For Deseret Power's Proposed WCFU

Pollutant	Proposed Emission Limit for WCFU (lb/MMBtu)	Lowest BACT Determination Anywhere for a CFB Boiler Project (lb/MMBtu)	Equivalent Annual Reduction (tons/year)
NO_x	0.080	0.07	63
SO_2	0.040	0.022	114
CO	0.15	0.10	316
H_2SO_4	0.0035	0.0024	7
Filterable PM	0.012	0.010	13
Condensible PM	0.019	0.005	88

NOTE #1: The Sevier Power Company project cited by commenters is permitted at 0.1 lb/MMBtu for NOx, 0.022 lb/MMBtu for SO2, 0.115 lb/MMBtu for CO, 0.0024 lb/MMBtu for H2SO4, and 0.015 lb/MMBtu. "Lowest BACT Determination" values listed above are at least as low.

NOTE #2: The proposed WCFU permit has no separate BACT emission limit for condensibles. The figure of 0.019 lb/MMBtu above is an estimate based on best information available to EPA and the proposed emission controls for the WCFU, as described in the draft Statement of Basis.

EPA believes it is unlikely that lower emissions than listed above could be achieved on any coal in the Region. As explained in Note #1 above, the figures listed as "Lowest BACT Determination Anywhere for a CFB Boiler Project" are at least as low as the BACT determination for each pollutant at the Sevier project cited by commenters. Further, based on "Average Coal Quality at Utah Mines, 2005," listed in the afore-

mentioned UGS report, it appears to EPA that the proposed coal for the Sevier project is at least as clean, in terms of ash content and sulfur content, as any other coals in the region. The lowest ash content of the coals listed in Table A8 of the UGS report is 8.5%. The ash content of the proposed coal for the Sevier project is lower, at 8.3%. The lowest sulfur content of the coals listed in Table A8 of the UGS report is 0.4%. The sulfur content of the proposed coal for the Sevier project is at least as low, at 0.40%. (Ref: Table A8 of the aforementioned UGS report; Table I-2 of the aforementioned "New Source Plan Review" for the Sevier project.)

The calculated cost and corresponding emission reductions described above lead to the following cost estimates, in dollars per ton of additional pollutant removed annually, to use alternative coal from another mine in the region, rather than waste coal from the Deserado mine:

Annualized Cost of Potential Emission Reductions Due to a Switch from Waste Coal at the Deserado Mine to Alternative Coal from Another Mine for Deseret Power's Proposed WCFU

Pollutant	Potential Emission Reduction (Alternative Coal versus Waste Coal)	Cost ($/ton)
NO_x	63 tons/yr	$ 212,698/ton
SO_2	114 tons/yr	$ 117,543/ton
CO	316 tons/yr	$ 42,405/ton
H_2SO_4	7 tons/yr	$1,914,285/ton
Filterable PM	13 tons/yr	$1,030,769/ton
Condensible PM	88 tons/yr	$ 152,272/ton
All (sum)	651 tons/yr	$ 20,583/ton

As mentioned in the draft Statement of Basis's discussion of alternative coal from other mines, there would also be substantial energy and environmental costs associated with obtaining coal from a mine other than the Deserado mine, due to the large number of truck trips to deliver the coal (more than 20 per day, assuming 50 tons payload per truck), at 200 miles round trip per load. The substantial energy expenditure in terms of diesel fuel, the amount of pollution from truck exhaust, and the increased traffic hazard on public highways, all make this option even more cost-prohibitive.

Based on the analysis above, EPA concludes that use of alternative coal from any other mine in the region, rather than waste coal from the Deserado mine, would be cost-prohibitive as a BACT option for the proposed WCFU, even if reductions of all pollutants are summed together and then the annualized cost in dollars-per-ton for emission reduction is calculated on that basis. (As shown above, summing the pollutants yields $20,583/ton, which is a lower dollar-per-ton BACT cost than looking at any one pollutant individually.)

The same annualized dollar-per-ton costs would be incurred if there was only a partial switch to alternative coal from another mine (i.e., coal blending). This is because a partial switch yields only partial emission reductions.

Regarding comparison to the cost of BACT that other similar sources have to bear (which EPA believes is best evaluated in terms of dollars per ton of additional pollutant removed, not simply in terms of what other sources pay for their coal as commenters have suggested), EPA is not aware of any BACT determination for a CFB boiler project anywhere in the U.S. where incremental cost effectiveness as high as $20,583/ton (the EPA-calculated economic cost for using coal from an alternative mine rather than waste coal from the Deserado mine), or as high as $20,241/ton (the EPA-calculated economic cost for using ROM coal from the Deserado mine rather than waste coal from the Deserado mine; see final Statement of Basis at page 28) has been considered reasonable for BACT for any pollutants, regardless of the type of BACT option being considered.

Although EPA considers the economic, energy and environmental costs associated with use of alternative coal for Deseret Power's project to be clearly excessive for BACT, EPA has nevertheless looked at some recent BACT determinations by other permitting authorities for similar projects, for purposes of comparison. EPA found the following:

1) In a PSD permit action in mid 2006 for Longleaf Energy Associates LLC, Longleaf Energy Station project, Georgia indicated that incremental cost effectiveness of $8,964/ton, comparing dry scrubbing to wet scrubbing for SO_2 control at a pulverized coal fired electric utility boiler, was excessive for BACT. Incremental and average cost effectiveness of the selected BACT option (dry scrubbing) was listed as $724/ton.

(Ref: Georgia's Preliminary Determination for SIP Permit Application #15846, page 62, dated July 2006, available online at: http://www.air.dnr.state.ga.us/airpermit/psd/dockets/longleaf/permitdocs/0990030pd.pdf.

2) In a PSD permit action in early 2005 for Rocky Mountain Power Inc.'s Hardin project, Montana indicated that incremental cost effectiveness of $23,855/ton, comparing dry FGD/spray dry absorber to wet FGD for SO_2 control, at a pulverized coal fired electric utility boiler, was excessive for BACT. Average cost effectiveness of wet FGD was listed as $1,395/ton. Average cost effectiveness of the selected BACT option (dry FGD/spray dry absorber) was listed as $918/ton.

(Ref: Montana's Permit Analysis for Hardin project, Permit #3185-02, pages 15 and 17, dated May 16, 2005, obtained from Montana Air Resources Management Bureau, in the Montana Department of Environmental Quality.)

3) In a PSD permit action in early 2007 for Southern Montana Electric Generation and Transmission Cooperative's CFB boiler project (Highwood Generating Station), Montana indicated that a "cost effective value" of \$27,365/ton for SO_2 control, for a control option employing a combination of limestone injection, low-sulfur coal and wet flue gas desulfurization (FGD), was excessive for BACT. Montana also indicated that a "cost effective value" of \$7,939/ton for SO_2 control, for a control option employing a combination of limestone injection, low-sulfur coal and dry FGD, was excessive for BACT.

The selected BACT option for SO_2 control, with a "cost effective value" of \$4,054/ton, employed a combination of limestone injection, low-sulfur coal, and hydrated ash reinjection. Montana did not indicate whether "cost effective value" means incremental cost effectiveness or total cost effectiveness.

(Ref: Montana's Permit Analysis for Highwood Project, Air Quality Permit #3423-00, page 23, dated May 30, 2007, obtained from the Montana Department of Environmental Quality Air Resources Management Bureau, Helena, Montana.)

4) In a PSD permit action in late 2006 for Cargill's Blair corn milling and ethanol production plant, Nebraska indicated that incremental cost effectiveness of \$5,900/ton, comparing limestone injection alone to limestone injection plus dry FGD, for SO_2 control at a CFB boiler, was excessive for BACT.

(Ref: Nebraska permit action CP06-0008, page 12 of Fact Sheet, dated September 8, 2006, available online at http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/cargill_blair_final_psd_permit.pdf.)

5) In a PSD permit action in late 2006 for ADM's Columbus corn milling and ethanol production plant, Nebraska indicated that incremental cost effectiveness of \$5,600/ton for NO_x control (comparing Selective Non-Catalytic Reduction (SNCR) at 0.07 lb/MMBtu to SNCR at below 0.07), and incremental cost effectiveness of \$6,700/ton for $SO_2/H_2SO_4/HF$ control (comparing limestone injection to "additional" limestone injection) at a CFB boiler, were excessive for BACT. Nebraska listed incremental cost-effectiveness of \$2,174 for the selected BACT option for NO_x control (SNCR at 0.07 lb/MMBtu).

Nebraska also listed average cost-effectiveness of \$5,200/ton for the selected BACT option for VOC control at the CFB boiler (wet scrubbing/packed tower),

(Ref: Nebraska permit action CPM02-0006, page 14 of Appendix B of Fact Sheet; pages 8, 9, 19 and 20 of Appendix D of Fact Sheet, dated August 4.2006, available online at: http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/adm_columbus_final_psd_permit.pdf.)

6) In a PSD permit in early 2005 for Montana-Dakota Utilities/Westmoreland Power, Gascoyne Generating Station project, North Dakota indicated that incremental cost effectiveness of $14,339/ton, comparing Selective Catalytic Reduction (SCR) at 0.04 lb/MMBtu to SNCR at 0.09 lb/MMBtu, for NO_x control at a CFB boiler, was excessive for BACT. Average cost effectiveness of SCR was listed as $7,545/ton. Average and incremental cost effectiveness of the selected BACT option (SNCR) was listed as $2,926/ton.

(Ref: North Dakota's Permit Application Analysis for Gascoyne Project, pages 65 and 68, dated March 2005, obtained from the North Dakota Department of Health, Environmental Health Section, Air Quality Division, Bismarck, ND.)

7) In a PSD permit action in early 2004 for Red Trail Energy's Richardton, ND, ethanol production plant, North Dakota listed incremental cost effectiveness of $10,252/ton, comparing wet FGD plus limestone injection to dry FGD (spray dryer absorber) plus limestone injection, for SO_2 control at a CFB boiler. Average cost effectiveness of wet FGD plus limestone injection was listed as $1,041/ton. Average cost effectiveness of dry FGD plus limestone injection was listed as $527/ton. North Dakota rejected wet FGD and determined that BACT is represented by dry FGD plus limestone injection.

(Ref: North Dakota's Permit Application Analysis for Red Trail Energy project, pages 38 and 40, dated May 2004, obtained from the North Dakota Department of Health, Environmental Health Section, Air Quality Division, Bismarck, ND.)

8) In a PSD permit action in early 2005 for River Hill Power Company's CFB boiler project, Pennsylvania indicated that incremental cost effectiveness of $15,975/ton, comparing use of the waste coal proposed by the permit applicant to use of the nearest alternative source of coal with lower sulfur content, for SO_2 control at the CFB boiler, was excessive for BACT.

Pennsylvania also indicated that all SO_2 BACT options involving wet FGD systems "were economically infeasible at an incremental dollar per ton value greater than $5,000 per ton of SO_2 removed."

Pennsylvania concluded that use of a spray dryer absorber or flash dryer absorber (i.e., dry FGD) was "economically feasible for the control of SO_2 at an incremental cost of $1,511.01 per ton of SO_2 removed."

(Ref: Pennsylvania's "Plan Approval Application Review Memo, Plan Approval Application #17-00055A," pages 10-11, dated May 2, 2005, obtained from the Commonwealth of Pennsylvania, Department of Environmental Protection, Northcentral Region, Air Quality Program.)

9) In a PSD permit action in early 2005 for Wellington Development's Greene Energy Resource Recovery Project, Pennsylvania indicated that incremental cost

effectiveness of at least $20,000/ton, comparing use of the waste coal proposed by the applicant to pre-combustion cleaning of the waste coal (excluding additional coal disposal costs after cleaning of the waste coal), for SO_2 control at the CFB boiler, was excessive for BACT. Pennsylvania also indicated that overall cost effectiveness of $5,764/ton, for limestone injection plus wet FGD for SO_2 control at the CFB boiler, was excessive for BACT.

(Ref: Pennsylvania's "Comment and Response Document," Air Quality File PA-30-00150A, page 6, dated June 21, 2005; Table 5-4 of PSD Permit Application, prepared by ENSR International, August 2004, page 5-29. Both documents were obtained from the Commonwealth of Pennsylvania, Department of Environmental Protection, Southwest Regional Office, Air Quality Program.)

10) In a PSD permit action in early 2004 for Intermountain Power's Unit 3 project, Utah indicated that incremental cost effectiveness of about $14,000/ton to $16,350/ton, comparing different types of baghouse fabric filter bags (Ryton-type bags versus specialty coated bags) for PM/PM_{10} control at a pulverized coal fired electric utility boiler, was excessive for BACT. Average cost effectiveness of the selected BACT option for PM_{10} control (a baghouse with Ryton-type bags) was $31/ton.

(Ref: Utah's Modified Source Plan Review for IPP3 project, pages 132-133, dated March 22, 2004, available online at: http://www.airquality.utah.gov/Permits/PmtPowerPlants.htm.)

11) In a PSD permit action in early 2007 for Basin Electric's Dry Fork Station project (a pulverized coal-fired electric utility boiler),Wyoming indicated that incremental cost effectiveness of $23,755/ton for NO_x control (comparing Selective Catalytic Reduction (SCR) at 0.043 lb/MMBtu to SCR at 0.040 lb/MMBtu) was excessive for BACT. Average cost effectiveness for SCR at 0.040 lb/MMBtu was listed as $2,004/ton. Average cost effectiveness for SCR at 0.043 lb/MMBtu was listed at $1,751/ton.

Although Wyoming determined that incremental cost effectiveness of $10,303/ton was reasonable for SCR at 0.043 lb/MMBtu, for other reasons described by Wyoming the selected BACT option for NO_x control was SCR at 0.05 lb/MMBtu, with incremental cost effectiveness of $3,512/ton and average cost effectiveness of $1,511/ton.

Wyoming also indicated that incremental cost effectiveness of $15,299/ton for SO_2 control (comparing dry FGD/spray dry absorber at 0.073 lb/MMBtu to wet FGD at 0.054 lb/MMBtu), was excessive for BACT. Average cost effectiveness of wet FGD at 0.054 lb/MMBtu was listed as $1,595/ton.

Although Wyoming determined that incremental cost effectiveness of $9,296/ton was reasonable for a spray dry absorber at 0.043 lb/MMBtu, for other reasons

described by Wyoming the selected BACT option for SO_2 control was a spray dry absorber at 0.08 lb/MMBtu, with average cost effectiveness of $1,159/ton; no incremental cost effectiveness listed by Wyoming for this BACT option..

(Ref: Wyoming's Permit Application Analysis for the Dry Fork project, NSR-AP-3546, pages 6, 7, 8, 10 and 11, dated February 5, 2007, obtained from Wyoming Air Quality Division, Cheyenne, WY.)

12) In a PSD permit action in early 2002 for Black Hills Power & Light's WYGEN2 project, Wyoming indicated that incremental cost effectiveness of $7,742/ton, comparing low-NO_x burners plus SCR at 0.06 lb/MMBtu to low-NO_x burners plus SCR at 0.08 lb/MMBtu, for NO_x control at a pulverized coal fired electric utility boiler, was reasonable for BACT. However, for other reasons described by Wyoming, the selected BACT option was low-NO_x burners plus SCR at 0.07 lb/MMBtu, with "total" (i.e., average) cost effectiveness somewhere between $4,067/ton (the average cost effectiveness to achieve 0.08 lb/MMBtu) and $4,156/ton (the average cost effectiveness to achieve 0.06 lb/MMBtu).

(Ref: Wyoming's Permit Application Analysis for the WYGEN2 project, NSR-AP-92, page 7, dated April 24, 2002, obtained from Wyoming Air Quality Division, Cheyenne, WY.)

13) In a PSD permit action in late 2006 for Black Hills Power & Light's WYGEN3 project, Wyoming indicated that incremental cost effectiveness of $14,609/ton, comparing a baghouse with fiberglass or polyphenylene sulfide filter bags (listed as capable of achieving 0.012 lb/MMBtu) to a baghouse with specialty filter bags such as Teflon (listed as capable of achieving 0.011 to 0.010 lb/MMBtu), for PM/PM_{10} control at a pulverized coal fired electric utility boiler, was excessive for BACT.

Average cost effectiveness of the selected BACT option (a baghouse with fiberglass or polyphenylene sulfide filter bags) was listed as $130/ton. Average cost effectiveness of a baghouse with specialty filter bags was listed as $134/ton.

(Ref: Wyoming's Permit Application Analysis for the WYGEN3 project, NSR-AP-3934, pages 10 and 11, dated October 9, 2006, obtained from Wyoming Air Quality Division, Cheyenne, WY.)

The pages cited above, for each of the 13 examples, are included in the Administrative Record for issuance of the WCFU permit.

Although this information is only on comparative economic costs of BACT options, not on comparative energy and environmental costs (which were generally not quantified by the permitting authorities), the information does seem to indicate that similar sources have typically not been expected to bear BACT costs, on an incremental cost effectiveness basis, as high as the incremental cost effectiveness for using alternative

sources of coal for Deseret Power's s project, in lieu of waste coal ($20,583/ton for alternative coal from another mine and $20,241/ton for alternative coal from the Deserado mine).

Regarding the Sevier project cited by commenters, the State of Utah presented no data in its "New Source Plan Review" on cost of BACT for any PSD pollutant, and none of the BACT options considered by Utah for that project involved alternative sources of coal. Further, no information was provided on cost of coal for the Sevier project.

This supplemental BACT analysis has not altered EPA's determination that use of alternative coal from the Deserado mine or from another mine, either partially or entirely in place of waste coal from the Deserado mine, should be eliminated as a BACT option, in terms of environmental, economic and energy costs, at Step 4 of the BACT analysis.

In summary, Comment #4.a has not resulted in any change to the permit; however, the Statement of Basis has been changed, to include the supplemental analysis described above.

4.b -- Sulfur Dioxide (SO_2):

Comment #4.b: One group of commenters asserted that the BACT analysis and proposed BACT limit for SO_2 are flawed because they do not reflect the maximum degree of reduction that can be achieved. EPA proposed an SO_2 emission limit of 0.055 lb/MMBtu (30-day average) when the uncontrolled SO_2 emissions are 1.9 lb/MMBtu or greater. EPA also proposed a calculated 30-day average SO_2 limit which is based on a 0.055 lb/MMBtu emission rate for the number of days at which the potential uncontrolled SO_2 emissions are 1.9 lb/MMBtu or higher, and a 0.04 lb/MMBtu emission rate for the number of days at which the potential uncontrolled SO_2 emissions are less than 1.9 lb/MMBtu. Individual supporting arguments from commenters are described below, along with EPA's responses

Comment #4.b.(1): Commenters alleged that EPA's proposed variable BACT limit does not reflect the maximum degree of reduction that can be achieved at a CFB boiler. By comparison, commenters cited two different coal-fired CFB power plants (Nevco and AES-Puerto Rico), with the same proposed SO_2 controls as Deseret's WCFU, that are required to meet an SO_2 BACT limit of 0.022 lb/MMBtu. Commenters calculated that the emission limit for AES-Puerto Rico equates to a 98.6% reduction in SO_2 emissions, which must be met on a three-hour average, despite a potential uncontrolled SO_2 emission rate of 1.6 lb/MMBtu, lower than Deseret's WCFU.

Response #4.b.(1): Partially agree. EPA does not agree with commenters that comparison with the Nevco project should lead to reconsideration of the SO_2 BACT emission limit in the draft WCFU permit. EPA does, however, agree with commenters that comparison with the AES Puerto Rico project should lead to such reconsideration, at least in regard to the "cutpoint" in coal quality. (NOTE: By "cutpoint," EPA means the level of uncontrolled SO_2 emission potential of the coal, in lb/MMBtu, that would trigger a switch from a straight 0.055 lb/MMBtu emission limit to a calculated emission limit of between 0.055 and 0.040 lb/MMBtu. A more detailed mathematical description of the "cutpoint" approach, as well as a description of the rationale for that approach, may be found in Step 5 of the SO_2 BACT analysis in the Statement of Basis.)

Comparison with Nevco: As stated on pages 77-78 of the Statement of Basis, Nevco will only have to achieve a control efficiency of 95.5% to meet its emission limit when burning average coal, and 97.2% when burning worst-case coal. The proposed limits for Deseret would reflect higher control efficiency than Nevco. As also stated in the Statement of Basis, if "average" coal for the WCFU (i.e., coal with uncontrolled SO_2 emission potential of about 1.71 lb/MMBtu) is burned for an extended period of time, such as a month or more, the variable BACT limit in the draft WCFU permit would approach the lower limit of 0.04 lb/MMBtu, which corresponds to a control efficiency of 97.7%. The proposed upper emission limit of 0.055 lb/MMBtu at the WCFU would reflect 98.8% control efficiency for "worst-case" coal (i.e., coal with uncontrolled SO_2 emission potential of 4.73 lb/MMBtu). These are both higher control efficiencies than required at the Nevco project for its average and worst-case coals.

Therefore, EPA does not believe that comparison to Nevco should lead to re-consideration of the proposed SO_2 emission limit for Deseret's WCFU project.

Comparison with AES Puerto Rico: Commenters also cited emission limits and theoretical control efficiencies required for the AES Puerto Rico facility. This project includes two CFB boilers burning Columbian coal that utilize limestone injection and dry scrubbers for SO_2 control, same as Deseret's WCFU project. The SO_2 emission limit for the AES Puerto Rico project is 0.022 lb/MMBtu on a 3-hour average. (Ref: PSD permit issued by EPA Region 2 on October 29, 2001 and revised on August 10, 2004, page 4, condition VIII.4-CFB.a.). However, the AES Puerto Rico permit also says "Emissions in excess of the applicable emission limit listed under Condition VIII of this permit, during periods of startup and shutdown, shall not be considered a violation of the applicable emission limit." (Ref: permit at page 15, condition XIV.7.)

This startup/shutdown exemption language does not appear in the draft WCFU permit. Instead, the draft WCFU permit says "The PSD BACT emission limits in this permit, as well as the modeling limits, apply at all times, including periods of startup, shutdown and malfunction." (Ref: draft WCFU permit at page 16, condition III.I.1.) Therefore, EPA believes that making a direct comparison of the stringency of the SO_2 emission limit in the AES Puerto Rico permit with the SO_2 emission limit in the draft WCFU permit is not entirely meaningful. Nevertheless, EPA has re-compared the theoretical control efficiency requirements of the two permits over the respective range of coal qualities, assuming steady-state operations apply and averaging times do not significantly affect those control requirements. This is explained in the step-by-step process below.

First, using mass balance, EPA calculated an uncontrolled SO_2 emission potential of the coal for the AES Puerto Rico facility, in lb/MMBtu, based on coal quality parameters of 0.8% sulfur content and 12,000 Btu/lb heat content cited by commenters for the 'worst case' coal. The result of EPA's calculation was 1.3 lb/MMBtu:

$$\frac{0.008 \text{ lb sulfur}}{\text{lb coal}} \times \frac{2 \text{ lb } SO_2}{\text{lb sulfur}} \times \frac{\text{lb coal}}{12{,}000 \text{ Btu}} \times \frac{1{,}000{,}000 \text{ Btu}}{\text{MMBtu}} = 1.3 \text{ lb } SO_2/\text{MMBtu}$$

To meet an emission limit of 0.022 lb/MMBtu, the AES Puerto Rico facility would need to achieve about 98.3% SO_2 control efficiency. (NOTE: These results differ from the results cited by commenters, which were 1.6 lb/MMBtu and 98.6% control. EPA therefore finds that the commenters' results were incorrect. Commenters did not provide an explanation of how they calculated 1.6 lb/MMBtu and 98.6% control, therefore EPA is unable to determine why commenters' results were incorrect. EPA finds that its own earlier results of 1.7 lb/MMBtu and 98.7% for 'worst-case' coal at AES Puerto Rico, cited on page 76 of the draft Statement of Basis, were also incorrect. This has been corrected in the final Statement of Basis.)

Second, EPA Region 8 obtained information on the sulfur content and heat content of coal that has been used historically at the AES Puerto Rico facility. EPA

Region 8 learned that the sulfur content varied from 0.49% to 0.75% during the fourth quarter of 2004 and the heat content was about 11,350 Btu/lb. From February of 2002 through June of 2003, the sulfur content varied from 0.53% to 0.85% and the heat content varied from 11,317 Btu/lb to 11,495 Btu/lb. From this information, EPA Region 8 found that the uncontrolled SO_2 emission potential of the actual coal ranges from about 1.3 lb/MMBtu ('worst-case' coal) down to about 0.88 lb/MMBtu ('average' coal). EPA Region 8 calculated that at the low end of this range, the AES Puerto Rico facility would need to achieve about 97.5% SO_2 control efficiency, to meet an emission limit of 0.022 lb/MMBtu. (Ref: Memorandum and attachments to the file by Mike Owens of EPA Region 8, dated August 8, 2007, included in the Administrative Record for issuance of the WCFU permit.)

Third, EPA Region 8 compared the above-mentioned control efficiencies for AES Puerto Rico to those that the WCFU would need to achieve to comply with the SO_2 emission limit in the draft WCFU permit. As noted above and on page 77 of the draft Statement of Basis, the WCFU would need to achieve about 98.8% control efficiency to comply with the upper emission limit of 0.055 lb/MMBtu, when burning 'worst-case' waste coal from the Deserado mine, and a control efficiency of about 97.7% to comply with an emission limit of 0.040 lb/MMBtu, when burning 'average' waste coal from the Deserado mine. Both of these control efficiencies are higher than the control efficiencies cited above for the range of coal at the AES Puerto Rico plant (98.3% for worst-case coal and 97.5% for average coal).

The above-mentioned comparison is somewhat misleading, however, for 'average' coal at the WCFU, because at the "cutpoint" in the draft WCFU permit (i.e., uncontrolled SO_2 emission potential of coal of 1.9 lb/MMBtu, only slightly higher than 1.71 lb/MMBtu for 'average' coal), the applicable emission limit would be the upper limit of 0.055 lb/MMBtu. Condition III.D.1.b.(ii)***(b)*** of the draft WCFU permit states that the calculated emission limit of between 0.055 and 0.040 lb/MMBtu only applies below the "cutpoint." Therefore, the statement on page 81 of the draft Statement of Basis, that a control efficiency of 97.9% would need to be achieved to comply with the applicable emission limit at the "cutpoint," is incorrect, because the statement was erroneously based on complying with an emission limit of 0.040 lb/MMBtu. The correct control efficiency that would need to be achieved at the 1.9 lb/MMBtu "cutpoint" is actually 97.1%, based on an applicable emission limit of 0.055 lb/MMBtu. This corrected control efficiency is lower than the 97.5% control efficiency that the AES Puerto Rico facility must achieve to meet its SO_2 emission limit of 0.022 lb/MMBtu when burning 'average' coal.

Based on this correction, EPA re-evaluated the appropriate level to set for the "cutpoint" and determined that, to require a minimum control efficiency of 97.5% across the range of coal qualities described in the permit application for the WCFU, the "cutpoint" would need to be 2.2 lb/MMBtu, rather than 1.9 lb/MMBtu. This would correspond to a control efficiency of 97.5%, to comply with an applicable emission limit of 0.055 lb/MMBtu when burning coal with uncontrolled SO_2 emission potential of 2.2 lb/MMBtu.

When burning coal above the revised "cutpoint," i.e., coal with uncontrolled SO_2 emission potential greater than 2.2 lb/MMBtu, to comply with the applicable emission limit of 0.055 lb/MMBtu the WCFU would need to achieve higher SO_2 control efficiencies than 97.5%, reaching 98.8% when burning worst-case coal. Below the revised "cutpoint," a calculated SO_2 emission limit of between 0.055 and 0.040 lb/MMBtu is applicable and needed control efficiencies range from 98.1% just below the cut-point (2.14 lb/MMBtu) to 97.7% for the average coal.

EPA believes this revised "cutpoint" is an appropriate approach for ensuring that the WCFU maintains a high level of SO_2 control over the wide range of coal quality, and reflects the maximum degree of SO_2 reduction that can be achieved, commensurate with SO_2 BACT determinations for other similar facilities (listed in the two tables in Step 5 of the SO_2 BACT analysis in the Statement of Basis), including Nevco and AES Puerto Rico. Specifically, this revised "cutpoint" ensures a minimum control efficiency of at least 97.5%, over the range of worst-case coal to average coal.

EPA Region 8 also reviewed 30-day average SO_2 CEMS data for the AES Puerto Rico facility, in quarterly CEMS reports from the years 2003 through 2006, and found a very low amount of excess emissions with regard to the emission limit of 0.022 lb/MMBtu on a 3-hour average. The reports seem to EPA Region 8 to indicate that an emission limit of 0.022 lb/MMBtu on a 30-day rolling average (and the corresponding control efficiencies) could consistently be met by the AES Puerto Rico facility, over the range of coal quality cited above. Therefore, EPA concludes that the revised "cutpoint" of 2.2 lb/MMBtu for the WCFU represents an overall SO_2 BACT determination that is achievable for a CFB unit with limestone injection and a dry scrubber for SO_2 controls. (Ref: Memorandum and attachments to the file by Mike Owens of EPA Region 8, dated August 8, 2007, included in the Administrative Record for issuance of the WCFU permit.)

Comment #4.b.(1) has resulted in the following changes to the permit and Statement of Basis: The final permit specifies a "cutpoint" of 2.2 lb/MMBtu, rather than 1.9 lb/MMBtu in the draft permit, for triggering applicability of the lower-tier SO_2 BACT emission limit in the permit. The Statement of Basis has also been revised, to add an explanation of why EPA has chosen a "cutpoint" of 2.2 lb/MMBtu, and to correct EPA's calculations for 'worst-case' coal at AES Puerto Rico, explained above, from 1.7 lb/MMBtu and 98.7% control efficiency to 1.3 lb/MMBtu and 98.3% control efficiency.

Comment #4.b.(2): Commenters alleged that while the draft Statement of Basis indicates a 98.8% SO_2 removal efficiency could be achieved with the CFB boiler and the spray dry absorber (draft Statement of Basis at pages 72-73), the proposed BACT emission limit for SO_2 does not reflect this level of control, because it is based on the absolute worst case uncontrolled SO_2 emission rate. Commenters indicated that the 0.055 lb/MMBtu limit reflects 98.8% SO_2 removal from the worst case design coal of 3,000 Btu/lb and 0.71% sulfur (which thus equates to an uncontrolled SO_2 emission rate of 4.73 lb/MMBtu). However, the expected *average* uncontrolled SO_2 emission rate is 1.71

(EPA's Statement of Basis at 15). Commenters concluded that, based on the average uncontrolled SO_2 emission rate, the 0.040 lb/MMBtu SO_2 limit (which would apply when the uncontrolled emission rate is lower than 1.9 lb/MMBtu) only represents a 97.7% SO_2 removal rate from average uncontrolled SO_2 emissions. Commenters argued that 97.7% is over a percentage point lower than the maximum degree of reduction that can be achieved.

Response #4.b.(2): Disagree. While the figures cited by commenters are correct, EPA does not agree that 97.7% control is inadequate for SO_2 BACT, for combustion of "average" waste coal at Deseret's WCFU. Considering that the worst-case coal for the WCFU has uncontrolled SO_2 emission potential two-and-a-half times higher than average coal (4.73 lb/MMBtu versus 1.71 lb/MMBtu), EPA does not believe an SO_2 control efficiency as high as that for worst-case coal (98.8%) can be achieved when burning average coal, which resulted in only 97.5% SO_2 control efficiency at AES Puerto Rico. As explained in response #4.b.(1) above, the two-tiered SO2 emission limit with the revised "cutpoint" compares favorably to the two projects cited by commenters (Nevco and AES Puerto Rico), in terms of SO_2 control efficiencies needed to comply with applicable SO_2 emission limits.

Comment #4.b.(2) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(3): Commenters alleged that EPA Region 8 previously made a "similar" comment to the Montana Department of Environmental Quality regarding the proposed Roundup power plant. Specifically, commenters cited EPA as having stated, in a December 18, 2002 letter to Montana, that "[w]hile use of the worst-case coal scenario might be appropriate for establishing a short-term (3-hour or 24-hour) SO_2 emission limit, we consider it inappropriate for establishing a 30-day average emission limit, especially considering that coal blending can be used at minimal additional cost (and is routinely used in the power plant industry) to eliminate or reduce the effect of coal sulfur 'spikes.'"

Response #4.b.(3): Disagree. By describing the comment to Montana as "similar," commenters appear to be suggesting that EPA only considered the worst-case coal scenario when proposing SO_2 BACT emission limits for Deseret's WCFU. This is not true. The Statement of Basis has a lengthy discussion (on pages 77-81) of how EPA set up a two-tiered limit. EPA's comments on Roundup are consistent with EPA's proposed approach of setting up this two-tiered limit for Deseret's WCFU, rather than setting a single limit based on worst case coal

Comment #4.b.(3) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(4): Commenters alleged that the Bonanza WCFU has requested to be authorized to burn washed or run-of-mine coal which will have lower uncontrolled SO_2 emissions than the worst case waste coal and thus could be used to eliminate coal sulfur spikes. Also, commenters stated, Deseret has indicated that the Bonanza WCFU will have continuous SO_2 monitoring at the inlet to the dry scrubber. Thus, commenters

argue, Deseret will know on a fairly instantaneous basis when the coal sulfur content is spiking and thus could adjust the fuel accordingly. Consequently, the 30-day average BACT limit should reflect this level of control off of the average uncontrolled SO_2 emission rate of 1.7 lb/MMBtu, which equates to a BACT emission limit of 0.021 lb/MMBtu.

Response #4.b.(4): Disagree. The authorization to burn washed or run-of-mine coal is not unlimited as implied by commenters, but is restricted in the draft WCFU permit, as follows: Condition III.E.2.b. only allows Deseret Power to burn washed or run-of-mine coal, rather than waste coal, during emergencies when waste coal is not available. For situations other than startup or emergencies, condition III.E.2.c. allows use of run-of-mine coal blended with waste coal in any ratio yielding up to 6,500 Btu/lb heat content. This corresponds to roughly a 50/50 blend. As explained in the draft Statement of Basis at page 10, Deseret Power requested this authorization for operational flexibility, such as in the event of operational difficulties arising from use of waste coal as sole fuel, or in the event of unexpected difficulties in meeting BACT emission limits, even though the WCFU is being designed specifically to burn waste coal, and even though use of run-of-mine or washed coal on a routine basis, in lieu of waste coal, would be prohibitively expensive for BACT. EPA already presented a cost analysis in the draft Statement of Basis demonstrating that use of washed or run-of-mine coal, either partially or entirely in place of waste coal, should be eliminated as a BACT option for cost reasons. (See draft Statement of Basis at pages 25-28.)

At Step 5 of the SO_2 BACT analysis, EPA stated that "Deseret Power will be permitted to use coal from the Deserado mine, consisting of either waste coal alone, or else a blend of waste coal and run-of-mine coal, yielding heat content of up to 6,500 Btu/lb. Based on the SO_2 BACT analysis above, EPA believes that the proposed 'second tier' SO_2 emission limit described above will represent BACT for coal from the Deserado mine with heat content up to at lest 6,500 Btu/lb, and will ensure a continued high degree of SO_2 emission control efficiency." (Draft Statement of Basis at page 82.)

EPA disagrees with commenters' argument that SO_2 CEMS data could be used to adjust fuel and eliminate coal sulfur spikes. The SO_2 monitors at the inlet to the scrubber do not reflect the uncontrolled SO_2 emission rate of the raw coal, since a great deal of SO_2 control occurs upstream of the scrubber inlet, via limestone injection in the CFB boiler itself. EPA does not agree that Deseret has that much ability to control spikes in coal sulfur content (see detailed discussion on page 80 of the Statement of Basis) and the scrubber inlet SO_2 monitor does not help with this problem.

Comment #4.b.(4) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(5): Commenters stated that at worst, the 30-day average SO_2 emission limit should reflect the percent reduction required at the AES-Puerto Rico facility, which has a similar level of uncontrolled emissions (albeit, worst case coal at AES-Puerto Rico is similar to average coal at the Bonanza WCFU). That facility's SO_2 emission limit reflects 98.6% reduction from uncontrolled emissions of 1.6 lb/MMBtu,

on a three-hour average basis. Thus, commenters concluded, the Bonanza WCFU SO_2 BACT limit should no higher than 0.024 lb/MMBtu, on a 30-day average to allow for the wide variability in sulfur content of the fuel.

Response #4.b.(5): Partially agree. As explained on pages 78-79 of the Statement of Basis, EPA does not agree that it is appropriate, considering the very high variability in coal quality expected to be encountered with Deseret's waste coal, to set a single SO_2 limit that applies to the entire range of possible fuel inputs at the WCFU. Also, as explained in response #4.b.(1), EPA does not agree with commenters' calculations of 1.6 lb/MMBtu and 98.6% control, for the "worst-case" coal scenario at the AES Puerto Rico plant. EPA calculates 1.3 lb/MMBtu and 98.3% control.

EPA does, however, agree that the WCFU should be expected to achieve a level of SO_2 reduction, which is commensurate with BACT determination at other similar facilities (listed in the two tables in Step 5 of the SO BACT analysis in the Statement of Basis), including AES Puerto Rico. Therefore, as explained in response #4.b.(1), EPA has revised the "cutpoint" that would trigger a change in the applicable emission limit for the WCFU, to ensure that the WCFU maintains a high level of SO_2 control over the wide range of coal quality, and to reflect the maximum degree of SO_2 reduction that can be achieved (97.5% or higher, over the range of worst-case coal to average coal), commensurate with SO_2 BACT determinations for other similar facilities including AES Puerto Rico.

Comment #4.b.(5) has resulted in the same changes to the permit and Statement of Basis that are described at the end of response #4.b.(1).

Comment #4.b.(6): Commenters alleged that EPA must also impose shorter term averaging time BACT limits consistent with the averaging times of the SO_2 NAAQS and PSD increments (i.e., 3-hour and 24-hour). Commenters cited an EPA statement, in a December 18, 2002 letter to Montana on the Roundup coal-fired electric utility project, that it is more appropriate to base shorter term average BACT limits on worst case uncontrolled emissions. (See comment #4.b.(3) above.) Thus, commenters concluded, the proposed BACT limit of 0.055 lb/MMBtu would be appropriate on a shorter term averaging time such as a three-hour average (similar to the AES-Puerto Rico permit).

Response #4.b.(6): Disagree, for three reasons. First, EPA set worst case modeling limits in the permit specifically to protect the short-term NAAQS and PSD increments. Second, the proposed SO_2 emission limits for Deseret's WCFU are two-tiered, unlike Roundup, and are not based solely on worst-case uncontrolled emissions. Third, Federal PSD rules at 40 CFR 52.21 do not require BACT limits for all averaging times of the PSD increments or NAAQS. EPA proposes modeling limits in the permit, separate from the BACT emission limits, to ensure that the assumed emission rates used for modeling PSD increment compliance and NAAQS compliance are not exceeded. See more detailed discussion at response #5.a.(1).

Comment #4.b.(6) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(7): Commenters argued that in addition, with a 30-day average SO_2 BACT limit based on average coal quality and a 3-hour average SO_2 BACT limit based on worst case coal quality, this would eliminate the need for EPA's proposed variable SO_2 limit, which commenters say would not result in the maximum degree of SO_2 emission reduction that could be achieved. Commenters stated that this is because EPA allows applicability to the variable SO_2 BACT limit to be based on a 30-day average of the uncontrolled SO_2 emission rate (Condition III.J.2. of the draft permit), which will allow the Bonanza WCFU to only have to comply with the higher SO_2 BACT limit with just a few days of spiked coal sulfur content over a 30-day period

Response #4.b.(7): Disagree. As explained on pages 78-79 of the Statement of Basis, since the quality of coal in the waste coal pile is highly variable and not entirely predictable, the two-tiered SO_2 limit is necessary to accommodate fuel variability while still ensuring that controls are maintained at a high level of efficiency over the entire range of predicted coal quality, in accordance with BACT. A 3-hour limit based solely on worst case coal quality would not ensure that controls are maintained at a high level of efficiency over the entire range of predicted coal quality.

Only in situations where coal quality is consistently above the cut-point level of 1.9 lb/MMBtu for uncontrolled SO_2 emission potential for prolonged periods (unlikely to happen frequently, considering the cut-point is 11% higher than what is predicted to be average coal quality of the waste pile) would the higher-tier emission limit of 0.055 lb/MMBtu be the actual 30-day SO_2 BACT limit. The 30-day limit is a weighted average, so having just a few days of high coal sulfur content over a 30-day period would not necessarily cause the applicable emission limit to revert to 0.055 lb/MMBtu. The applicable emission limit might very well remain closer to the lower limit of 0.04 lb/MMBtu. See Statement of Basis discussion on page 80.

Comment #4.b.(7) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(8): Commenters argued that the 5-day lag in comparing 30-day average uncontrolled SO_2 emissions to 30-day average controlled emission rates (Condition III.D.1.b.(ii)*(b)* of the draft permit) means that the proposed BACT emission limits would not ensure maximum SO_2 emission reductions on a continuous basis.

Response #4.b.(8): Disagree. EPA believes that the 5-day lag time, allowed under condition III.D.1.b. of the draft WCFU permit, is justified due to the SO_2 sampling time turnaround. EPA does not believe it is appropriate to retroactively apply a more restrictive limit upon a source once coal sampling results are obtained. As explained on page 80 of the draft Statement of Basis,

> "Deseret Power states that it will not be possible for them to determine the analysis of the fuel being fired, as it is being fired. Average samples of fuel being loaded into the silo will be taken to Deseret's laboratory for analysis. Deseret

states that results will take a minimum of one day and may take up to three days. If there will be a substantial delay in getting the results of the in-house analysis, Deseret states that the coal may have to be sent to an outside laboratory for analysis, which may take up to five days. Results therefore might not be available until three days or more after fuel is loaded to the fuel input silo. The applicable SO_2 tier limit would not be known to the WCFU operator until the coal analysis is received."

Although there will be a scrubber inlet SO_2 monitor in addition to the daily coal sampling, the scrubber inlet monitor will not measure the true uncontrolled SO_2 emission potential of the coal, either in practice or in the permit, due to the SO_2 control that occurs in the CFB boiler via limestone injection, upstream of the scrubber and the scrubber inlet SO_2 monitor. Therefore, the scrubber inlet SO_2 monitor will not eliminate the need for daily coal sampling and the associated lag time. As explained by Deseret Power in a January 9, 2006 e-mail to EPA (included in the Administrative Record for issuance of the WCFU permit), SO_2 measurements at the scrubber inlet monitor "will be used to control limestone flow to the furnace to maintain a selected SO_2 inlet to the dry scrubber." The scrubber inlet SO_2 monitor is not required by the draft WCFU permit, only a scrubber outlet SO_2 monitor, for demonstrating compliance with the SO_2 BACT emission limit.

Comment #4.b.(8) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(9): Commenters asserted that the draft permit also fails to address BACT requirements when Deseret is using "run-of-mine" coal, either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine (as allowed by condition III.E.2.c. of the draft permit). Commenters stated that EPA has indicated, in correspondence to Deseret, that BACT needs to be met "for the entire range of operating conditions." Yet, commenters argue, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part.

Response #4.b.(9): Disagree. EPA's SO_2 BACT analysis did address this situation. See discussion on page 82 of the draft Statement of Basis. Comment #4.b.(9) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(10): Commenters argued that to address the variation expected in uncontrolled SO_2 emissions at the Bonanza WCFU, EPA must include a SO_2 removal efficiency requirement as BACT in addition to the BACT emission limits that reflects the maximum degree of emission reduction that can be achieved given the variability in uncontrolled SO_2 emissions. Commenters note that EPA Region 8 recommended a similar approach in its comments on the proposed Roundup power plant in Montana. Specifically, EPA stated "[a] minimum required SO_2 scrubber efficiency should be included in the permit, to ensure proper operation and maintenance of the scrubber, and to ensure that SO_2 emissions are minimized at all times, regardless of the sulfur content in the coal."

Response #4.b.(10): Disagree. The Roundup facility in Montana is a pulverized coal (PC) fired unit, not a circulating fluidized bed (CFB) unit like Deseret's proposed WCFU. A PC fired unit uses a SO_2 scrubber as the single stage of SO_2 control, hence the overall control efficiency can easily be measured via CEMS at the scrubber inlet and outlet. A CFB unit, however, uses two stages of SO_2 control. As explained on page 12 of the Statement of Basis, the first stage is limestone injection into the CFB combustor unit and the second stage is a dry SO_2 scrubber downstream. For this two-stage system of control, overall control efficiency cannot be easily measured on a real-time basis. The proposed two-tiered SO_2 limit for the WCFU is a means to deal with the high coal quality variability and unpredictability of the waste coal supply and maintain an emission limit that ensures SO_2 emissions are controlled to a BACT level at all times.

Comment #4.b.(10) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(11): Commenters asserted that, contrary to EPA's approach in the proposed limits in this permit, the percent reduction BACT requirement must be based on at least a daily average. Given the wide variability of uncontrolled SO_2 emissions allowed by the permit, calculating uncontrolled SO_2 emissions on a 30-day average would not ensure the maximum degree of SO_2 emissions reductions on those days when 100% "run-of-mine" coal is being burned.

Response #4.b.(11): Disagree. For situations other than startup or emergencies as defined in permit conditions III.E.2.a and b, permit condition III.E.2.c. allows use of run-of-mine coal blended with waste coal in any ratio yielding up to 6,500 Btu/lb heat content on a 30-day rolling average. This is roughly equivalent to a 50/50 blend, not 100% run-of-mine coal. As explained on page 82 of the Statement of Basis, EPA believes that the proposed 'second tier' SO_2 emission limit will represent BACT for coal from the Deserado mine with heat content up to at least 6,500 Btu/lb, and will ensure a continued high degree of SO_2 emission control efficiency. With the revised coal "cutpoint" described in response #4.b.(1) above, EPA calculates that control of at least 97.5% will be needed to meet the two-tier SO_2 emission limit for the WCFU, for the range of coal quality from worst-case coal to average coal. As explained in response #4.b.(1), EPA believes this level of control is commensurate with SO_2 BACT determinations at other similar sources cited by commenters.

Comment #4.b.(11) has not resulted in any change to the permit or Statement of Basis.

Comment #4.b.(12): Commenters indicated that a 24-hour average percent SO_2 removal should be required as part of the BACT determination, as it would effectively cover all of the various operating scenarios at the Bonanza WCFU.

Response #4.b.(12): Disagree. In a sense, the two-tiered limits are daily averages, as the 30-day weighted average is determined based on each day's coal quality.

Each “daily average” limit – either 0.055 or 0.040 lb/MMBtu - is given a weight depending on the number of days that daily limit applies over a 30-day period. There is a strong incentive for Deseret to keep controls running at their maximum capacity in order to ensure they meet their two-tiered emission limit, especially given the unpredictability of their coal source. Comment #4.b.(12) has not resulted in any change to the permit or Statement of Basis.

In summary comments #4.b.(1) through (12) have resulted in the changes to the permit and Statement of Basis described at the end of response #4.b.(1).

4.c -- Nitrogen Oxide (NO_x):

Comment #4.c: One group of commenters indicated that EPA did not adequately evaluate all of the technologies that could be employed at the Bonanza WCFU to reduce NO_x emissions and thus, the NO_x BACT determination does not reflect the maximum degree of NO_x reduction that can be achieved at the Bonanza WCFU. Individual arguments from commenters are described below, along with EPA's responses

Comment #4.c.(1): Commenters asserted that EPA eliminated evaluation of several NO_x control options as infeasible for a CFB boiler. Those options eliminated include flue gas recirculation and overfire air. See Statement of Basis at 30. Yet, commenters stated, a 1999 EPA guidance document identifies these two controls as options for NO_x control at CFB boilers. (Ref: Technical Bulletin: Nitrogen Oxides (NO_x), Why and How They Are Controlled, EPA-456/F-99-006R, November 1999.)

Commenters further stated that the Technical Bulletin identifies several other options for NO_x control at fluidized bed boilers that were not evaluated in the Bonanza WCFU NO_x BACT analysis, including: natural gas reburn, low excess air, reduced air preheat, reducing residence time at peak temperature through injection of steam, fuel reburning, non-thermal plasma reactor, and sorbent in combustion chamber/duct. Commenters argue that these technologies should have been evaluated by EPA, possibly in combination with SCR and SNCR, to determine the maximum degree of NO_x reduction that can be achieved.

Response #4.c.(1): Partially agree. The draft Statement of Basis should have mentioned the Technical Bulletin and discussed the control techniques listed in it. EPA has since prepared that discussion, which is presented below and is included in the final Statement of Basis. As presented below, EPA finds that each of the above-listed control techniques should be eliminated from further discussion as a BACT control option, due to one or more of the following reasons:

(1) ineffective or physically impossible at the WCFU,
(2) an inherent part of Deseret's proposed CFB boiler design,
(3) already proposed for the WCFU, or
(4) not commercially available.

This discussion therefore does not alter EPA's NO_x BACT determination for the WCFU. Findings are summarized in the table below, followed by individual explanations.

RESULTS OF NO_X CONTROL TECHNOLOGY EVALUATION ARISING FROM EPA TECHNICAL BULLETIN

	Addressed in Statement of Basis	Not Effective or not Physically Possible	Already Proposed to be Included	Not Commercially Available
Natural Gas Reburn	X	X		
Low Excess Air	X		X	
Reduced Air Preheat		X		
Reducing Residence Time		X		
Fuel Reburning	X	X		
Non-Thermal Plasma Reactor				X
Sorbent Injection	X		X	

Introductory discussion of thermal NO_x: The principal NO_x formation mechanism, thermal NO_x, arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x forms in the highest temperature regions of the combustion chamber (i.e. the air/fuel interface). Limiting the combustion temperature below 2,800^{o}F is sufficient to limit thermal NO_x. (Ref #1: R.T. Waibel, *Ultra Low NO_x Burners for Industrial Process Heaters*, Second International Conference on Combustion Technologies for a Clean Environment. Lisbon, Portugal, July 19-22, 1993. Figure 4, p. 5. Ref #2: IBO Industrial Emissions Control Technology III. Milwaukee, Wisconsin, August 1-3, 2005. p. 14.)

Most of control techniques listed in the table above act on thermal NO_x. These include natural gas reburn, low excess air, reduced air preheat, reducing residence time, and fuel reburning. The combustion temperature of a CFB boiler, by nature of its design, is much lower than that of a pulverized coal (PC) boiler (1,500^{o}F versus 3,000^{o}F). (Ref: Western Governors Association Technology Working Group Report, undated, page 10.) This lower combustion temperature results in virtually no thermally-generated NO_x. Because of this, control techniques designed to reduce NO_x emissions by reducing the combustion temperature, and thus reducing thermal NO_x, were not considered to have practical potential for application to coal-fired CFB boilers and thus were eliminated as control options at Step 1 of the BACT analysis. EPA explained this on page 31 of the draft Statement of Basis, in regard to Flue Gas Recirculation. Nevertheless, since the above-mentioned control techniques were listed in the EPA Technical Bulletin specifically in regard to CFB units, EPA has prepared the following explanations of why those techniques were eliminated as control options for the WCFU.

Also discussed below are two control techniques that are already proposed to be included for the WCFU, either as an inherent part of the CFB boiler design (low excess air), or as the chosen control option (sorbent injection, a.k.a. Selective Non-Catalytic Reduction). Also discussed are two control techniques that may have practical potential

for application to coal-fired CFB boilers, but are not known to be commercially available for CFB units (non-thermal plasma reactor and carbon injection into the combustion chamber). These techniques have therefore also been eliminated as control options for the proposed WCFU.

Descriptions of individual techniques below were taken from the above-mentioned EPA Technical Bulletin

Natural gas reburn – This is considered to be the same method as generic "fuel reburning," which was identified by the commenters as a separate control technique. The principles are the same whether the additional fuel reburned is natural gas, fuel oil, or coal. See "Fuel reburning" below.

Low excess air – Excess air flow for combustion has been correlated to the amount of thermal NO_x generated. Limiting the net excess air flow to less than 2% can strongly limit NO_x content of flue gas at pulverized coal fired boilers. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach.

A certain amount of excess air is required to maintain flame stability and provide satisfactory combustion. Limiting excess air to such a low level would also increase emissions of carbon monoxide (CO).

Reducing the amount of excess air may be a valid way to reduce NO_x emissions from an older CFB unit with poor combustion controls. However, the unit proposed by Deseret is a new unit with state-of-the-art combustion controls. One of the goals of those controls is to minimize excess air to maximize boiler efficiency. If one were to consider reducing excess air further than the design rate, it would result in increased CO emissions and disrupt the stable operation of the unit. Further, this control technique acts primarily on thermal NO_x and therefore, while it may have substantial effect on NO_x emissions at pulverized coal fired boilers, it has much less effect on NO_x emissions at combustion sources such as CFBs that operate at low combustion temperatures.

This control technique was addressed on page 31 of the Statement of Basis, through EPA's reference to Table 1.1-2 of AP-42, which indicates it does not have practical potential for application to coal-fired CFB boilers. It has therefore been eliminated at Step 1 of the BACT analysis.

Reduced air preheat – Preheating the combustion air cools the flue gases, reduces the heat losses, and gains efficiency. However, this can raise the temperature of combustion air to a level where NO_x forms more readily. By reducing the amount of air preheat, the combustion temperature is lowered and NO_x formation is suppressed. However, reducing the amount by which the incoming combustion air is preheated carries a significant efficiency penalty of up to 1% per 40^oF. (Ref: above-mentioned EPA Technical Bulletin on NO_x control, page 12.) This reduction in efficiency would increase emissions of all criteria pollutants. As mentioned in the "Introductory

discussion of thermal NO_x"above, the combustion temperature of a CFB boiler, by nature of its design, is much lower than that of a pulverized coal (PC) boiler and results in virtually no thermally-generated NO_x. Therefore, reduced air preheat is not considered to be an effective NO_x control option for coal-fired CFB boilers, i.e., it does not have practical potential for application to CFB boilers for NO_x control. It has therefore been eliminated at Step 1 of the BACT analysis.

Reducing residence time at peak temperature through injection of steam – This control technique involves injection of water or steam, which causes the stoichiometry of the mixture to be changed and adds steam to dilute calories generated by combustion. Both of these actions cause combustion temperature to be lower. If temperature is sufficiently reduced, thermal NO_x will not be formed in as great a concentration.

In order to control NO_x, steam is typically injected directly into the flame to reduce the adiabatic flame temperature. In a CFB boiler, this is not physically possible, as combustion occurs throughout the fluidized bed. As with reduced air preheat, injecting steam would reduce boiler efficiency and result in increased emissions of all pollutants.

This control technique is addressed in the introductory discussion of thermal NO_x above and is not considered to be an effective control option for coal-fired CFB boilers, i.e., it does not have practical potential for application to CFB boilers for NO_x control. It has therefore been eliminated at Step 1 of the BACT analysis.

Fuel reburning – This control technique consists of recirculation of cooled flue gas with added fuel, similar to Flue Gas Recirculation (FGR) discussed on page 31 of the Statement of Basis. With fuel reburn, calories are diluted and the primary combustion temperature can be lowered. In other words, the peak flame temperature can be lowered through adsorption of the combustion heat by the relatively inert flue gas. As explained in the Statement of Basis, and in the introductory discussion of thermal NO_x above, this control technique acts on thermal NOx and is not considered to be effective on combustion sources such as CFBs that operate at low combustion temperatures. As such, it does not have practical potential for application to CFB boilers for NO_x control. It has therefore been eliminated at Step 1 of the BACT analysis.

Non-thermal plasma reactor – This control technique involves using methane and hexane as reducing agents. Non-thermal plasma has been shown to remove NO_x in a laboratory setting with a reactor duct only two feet long. The reducing agents were ionized by a transient high voltage that created a non-thermal plasma. The ionized reducing agents reacted with NO_x and achieved a 94% destruction efficiency. There are indications that an even higher destruction efficiency can be achieved. A successful commercial vendor uses ammonia as a reducing agent to react with NO_x in an electron beam generated plasma. Such a short reactor can meet available space requirements for virtually any plant. The non-thermal plasma reactor could also be used without reducing agent to generate ozone and use that ozone to raise the valence of nitrogen for subsequent absorption as nitric acid.

Trinity Consultants investigated the non-thermal plasma reactor as a NO_x control option and advised Deseret Power that it is not known to be commercially available. (Ref: E-mail from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, November 13, 2006.) Therefore, while this control technique might be considered a technology transfer control option at Step 1 of the BACT analysis, it is eliminated at Step 2 as technically infeasible because it is not known to be commercially available for NO_x control at CFB boilers.

Sorbent in combustion chamber/duct.—This control technique involves injection of limestone into the combustion zone. Injection of ammonia (Selective Non-Catalytic Reduction) is also already included in the design of the proposed WCFU.

According to the above–mentioned EPA Technical Bulletin on NO_x control, another version of sorbent injection "uses carbon injected into the air flow to finish the capture of NO_x. The carbon is captured in either the baghouse or the ESP just like other sorbents." (Ref: Bulletin at page 19.) Although carbon injection is an emerging technology used to reduce mercury emissions, Deseret Power is not aware of it having been used anywhere to control NO_x. (Ref: E-mail dated November 13, 2006, from Ed Thatcher of Deseret Power to Mike Owens of EPA Region 8.) EPA is similarly not aware of carbon injection having been used anywhere to control NO_x. (Ref: Memorandum from Mike Owens of EPA Region 8 to Deseret Bonanza WCFU PSD Permit file, dated August 8, 2007.) Carbon injection for NO_x control is therefore eliminated at Step 2 of the BACT analysis as technically infeasible because it is not known to be commercially available for that purpose.

In summary, the evaluation and discussion above does not alter EPA's NO_x BACT determination of 0.080 lb/MMBtu for the WCFU. Comment #4.c.(1) has not resulted in any change to the permit; however, the Statement of Basis has been revised to include the discussion of potential NO_x control options above.

Comment #4.c.(2): Commenters asserted that while EPA required evaluation of selective catalytic reduction (SCR) on the proposed CFB boiler, SCR was improperly eliminated from the BACT review. First, EPA required evaluation of low temperature SCR, but Deseret apparently found that low temperature SCR was only applied to natural gas applications.

Commenters cited a memorandum from Don Shepherd to John Notar (both in the Air Resources Division at the National Park Service) regarding the NEVCO Energy – Sevier Power – Engineering Analysis, in which Mr. Shepherd stated "[w]hen the question of application of SCR to a CFB was raised at the Pittsburgh workshop [on selective catalytic reduction and non-catalytic reduction for NO_x control], one consultant stated that he knew of no reason why it could not be done. (In fact, one presenter in Pittsburgh suggested that addition of limestone, as would be inherent in a CFB, is desirable in counteracting the potential catalyst-poisoning effects of arsenic found in many coals)." Commenters argued that the question which should have been posed is whether SCR

could be applied to coal-fired CFB boilers. Commenters cited a statement in EPA's draft 1990 New Source Review Workshop Manual that opportunities for technology transfer must be identified and evaluated in the BACT analysis.

Response #4.c.(2): Disagree. EPA's draft Statement of Basis did, in fact, evaluate whether or not SCR could be applied to coal-fired CFB boilers.

With regard to statements from the National Park Service (NPS) about application of SCR to CFBs, the draft Statement of Basis (at page 32) explained that EPA asked Deseret Power to contact SCR vendors, based on NPS information about low-temperature SCR as a possible option. Specifically, Deseret Power was requested to find out if low-temperature SCR is commercially available. The answer was no. The vendors cited by the NPS as possible suppliers of low-temperature SCR informed Deseret Power that they actually provide SCR technology only for natural gas applications, not for coal-fired boilers. EPA concluded that low-temperature SCR is not a technically feasible NO_x control option for the WCFU, as it is not commercially available to be applied to this project. (Draft Statement of Basis at page 32.)

With regard to step 2 (technical feasibility) of the top-down BACT analysis, two key concepts are important in determining whether an undemonstrated technology is feasible – "availability" and "applicability." *See Prairie State*, slip op, at 17; Three *Mountain Power*, 10 E.A.D. at 42-43 n.3. A technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

The draft Statement of Basis explained that EPA did identify SCR (excluding low-temperature SCR) as a technically feasible control option, and asked Deseret Power to evaluate the possibility of reheating the flue gas downstream of the baghouse to the temperature range known to be effective for SCR use. This evaluation included a detailed cost estimate described in the Statement of Basis. EPA concluded that the economic impacts of reheat, without even considering the higher capital cost of SCR versus SNCR, justified elimination of SCR as a BACT control option. (Draft Statement of Basis, pages 32-35.)

Comment #4.c.(2) has not resulted in any change to the permit or Statement of Basis.

Comment #4.c.(3): In a second argument regarding SCR, commenters asserted, "while EPA did require the evaluation of whether the flue gas downstream of the baghouse could be reheated to the temperature range known to be effective for SCR use (650-750 F) (Statement of Basis at 32), EPA should also have required evaluation of reheating the gas stream to the temperature range at which low temperature SCR could be used." Commenters argued that, according to the Institute of Clean Air Companies, low temperature catalysts can work in the range of 350 – 550 F. (Commenters cited the

ICAC website at http://www.icac.com/i4a/pages/index.cfm?pageid=3399, under NO_x Control Technologies.) Thus, commenters argued, EPA should have required Deseret Power to evaluate heating the gas stream up to 350 F and using low temperature SCR, which would use considerably less fuel than needed to reheat the gas stream to 650 F.

Response #4.c.(3): Disagree, for three reasons:

First, EPA explained in the draft Statement of Basis (at page 32), that low-temperature SCR was eliminated as technically infeasible because it is not commercially available to be applied to this project.

Second, EPA's cost analysis for reheat (on pages 34-35 of the draft Statement of Basis) was based on raising the stack temperature to 480F – as supplied by Deseret. This is within the range of 350-550F, as described by the ICAC noted above. Based on the ICAC website cited by commenters, "(i)n clean, low temperature (350-550F) applications, catalysts containing precious metals such as platinum and palladium are useful." EPA described the high cost results for reheat in the draft Statement of Basis (pages 34-35). The high cost results were only for reheat and did not include any of the substantially higher installation costs for SCR versus SNCR. This additional cost would undoubtedly negate any reduction in cost achieved by lowering the temperature threshold from 480 to 350F.

Third, commenters have not come up with any new evidence that low-temperature SCR could work.

Comment #4.c.(3) has not resulted in any change to the permit or Statement of Basis.

Comment #4.c.(4): In a third argument regarding SCR, commenters asserted that the presumed emission limit that could be met with SCR should have been lower than 0.04 lb/MMBtu used in the draft Statement of Basis at 33. Commenters stated that EPA did not provide any rationale for this presumed NO_x emission rate with SCR, except to cite to the level assumed by North Dakota in its BACT analysis for Gascoyne. Commenters argued that EPA should have instead evaluated a NO_x emission limit based on the maximum degree of emission reduction that can be achieved with SCR. Commenters stated that, according to Babcock & Wilcox, commercial SCR installations have shown that 90% NO_x reductions can be achieved with low ammonia slip, and that Babcock & Wilcox states that up to 95% NO_x control can be achieved with SCR. Thus, commenters concluded, considering the NO_x emission rate without SCR of 0.15 lb/MMBtu, which EPA indicated was an overestimate of NO_x emissions expected from the Bonanza WCFU (Statement of Basis at 34-35), the appropriate NO_x emission rate with SCR to evaluate would be at most 0.015 lb/MMBtu rather than the assumed 0.04 lb/MMBtu.

Response #4.c.(4): Partially agree. EPA has no definitive evidence that 0.015 lb/MMBtu could be achieved with SCR at the proposed Deseret WCFU. Further, EPA

does not agree that 0.04 lb/MMBtu is not a reasonable presumption for lowest emission rate that could be met with SCR at the Deseret WCFU. Nevertheless, EPA does agree it is conceivable a lower emission rate than 0.04 lb/MMBtu could be met with SCR. Since 90% NO_x removal from SCR is believed to be achieved at some facilities, and since Deseret Power has not provided more case-specific information for SCR capabilities for its WCFU project, EPA has revised its cost analysis, based on the Babcock & Wilcox information cited by commenters. The revised analysis reflects the possibility that a lower NO_x emissions rate than 0.04 lb/MMBtu could be achieved with SCR, as detailed in response #4.c.(5) below.

Comment #4.c.(4) has not resulted in any change to the permit; however, the Statement of Basis has been changed, to reflect this revised analysis of SCR described in response #4.c.(5) below.

Comment #4.c.(5): Based on the rationale in comments #4.c.(2) through (4) above, commenters asserted that the analysis for SCR must be re-evaluated to consider whether low temperature SCR could work on the Bonanza CFB boiler, either with or without flue gas reheating, and considering a NO_x emission rate that reflects the maximum degree of emission reduction that can be achieved.

Response #4.c.(5): Partially agree. EPA does not agree that the analysis for SCR must be re-evaluated to consider whether low temperature SCR could work. As explained in the Statement of Basis, and as explained in responses #4.c.(2) and (3) above, EPA concluded that low-temperature SCR is not a technically feasible NO_x control option for the WCFU, as it is not commercially available to be applied to this project.

EPA does agree, however, that the analysis for SCR with flue gas reheating should be revised to reflect a lower NO_x emissions rate achievable with SCR than 0.04 lb/MMBtu. The revised analysis is below. Most of the text is the same as in the draft Statement of Basis, but with revised cost calculations.

In order to be responsive to the commenters' assertion that 90% NO_x reduction could be achieved by installation of SCR on the Deseret WCFU, EPA has re-evaluated the cost-effectiveness of reheating the flue gas, in terms of the possibility of achieving a final NO_x rate of 0.015 lb/MMBtu rather than 0.04 lb/MMBtu. Note that this does not include the other capital and operating costs associated with purchasing, installing, operating, and maintaining the SCR system, so this analysis substantially underestimates the true cost per ton of NO_x reductions that would be incurred by Deseret, if SCR were applied to this project. The SCR analysis below is a modification to the draft Statement of Basis to reflect the final emission rate of 0.015 lb/MMBtu cited by commenters. In addition, consideration was given to the additional NO_x emissions generated by distillate fuel combustion when calculating total cost effectiveness, which should have been done in the draft Statement of Basis analysis.

a. Selective Catalytic Reduction. As noted above, for SCR to be a technically feasible NO_x control option for this project, flue gas reheating would be

required downstream of the particulate controls. This would involve significant additional fuel cost. The cost and environmental impacts are discussed below. Even without flue gas reheating, a SCR system does require some additional energy in order to overcome the pressure drop over the SCR catalyst beds; however, this has not proven to be a significant energy or economic impact for employing SCR technology on coal-fired power plants.

With any SCR installation, there are some commonly noted adverse environmental impacts. These would include ammonia slip emissions, catalyst disposal, and potential ammonia handling hazards. These impacts are usually deemed to be offset by the environmental benefits of significant NO_x reduction from the SCR system. For example, with the SCR system located downstream of the particulate and SO_2 control devices in order to deal with technical problems associated with a CFB application, there may be additional condensible particulate emissions resulting from the conversion of SO_2 to SO_3 and eventually to H_2SO_4 over the catalyst bed.

Another adverse environmental impact is the additional emissions from combustion of distillate fuel oil or propane for flue gas reheating. Deseret Power has calculated a required heat input of 99.2 MMBtu/hr to raise the temperature of the flue gas from 275 F to 480 F. The 480 F used by Deseret Power is on the low end of, or even below, where an SCR can most effectively operate. Thus, the fuel consumption values may actually be higher than calculated by Deseret.

Since there are no natural gas lines into Deseret Power's Bonanza plant, the only reheat options are distillate fuel oil or propane. EPA has calculated the emissions based on AP-42 emission factors. These emissions are presented in the table below. The calculations assume heat rating of the distillate fuel oil to be 0.14 MMBtu/gal, which equals 710 gallons per hour. For propane, the calculations assume 0.0905 MMBtu/gal, which equals 1,100 gallons per hour.

The difference in emission rates between SNCR and SCR would be 0.065 lb/MMBtu (i.e., 0.08 minus 0.015). Assuming CFB operation at 90% of capacity on an annual average, this difference would be equivalent to a NO_x reduction of 370 tons per year:

$$(0.08 \text{ lb/MMBtu} - 0.015 \text{ lb/MMBtu}) \times (1{,}445 \text{ MMBtu/hr}) \times (8{,}760 \text{ hr/yr}) \times (0.9) \times (1 \text{ ton}/2{,}000 \text{ lb}) = 370 \textbf{ tons/year}$$

With distillate reheat, the net NO_x reduction would be 308 tons per year (i.e., 370 minus 62). With propane reheat, the net NO_x reduction would be 278 tons per year (i.e., 370 minus 92). These figures are shown in the table below.

Estimated Emissions From Reheating of CFB Flue Gas
To Accommodate Use of Conventional SCR
At Deseret Power's Proposed WCFU

Pollutant	Distillate Oil Emissions (tons/year)	Propane Emissions (tons/year)
PM (total)	10	3
SO_2	3	Negligible
NO_x	62	92
VOC	1	2
CO	16	15

Even without considering reheat cost, the annualized cost of SCR is several times greater than SNCR, due to higher capital and operating costs. (Example: PSD permit application dated August 2005, for South Heart CFB boiler project in North Dakota, calculates the annualized capital recovery cost for SCR to be about six times as much as for SNCR. Ref: Page 4-16 of the permit application, included in the Administrative Record for issuance of the WCFU permit.) As explained above, SCR installed downstream of particulate controls would also involve reheat cost. Deseret Power provided cost figures for only the supplemental fuel that would be required to reheat the flue gas so that SCR could be used. No additional costs were calculated for capital, installation, or operation of the SCR system or capital, installation, and other non-fuel operational costs for the reheat system. Hence, this is a very conservative cost analysis, since as mentioned above, these additional capital, installation and operational costs for the SCR and reheat system would likely be substantial. The lowest-cost option for reheat fuel was calculated to be distillate oil at $12,411,476 per year, based on 6,205,738 gallons per year at $2.00 per gallon.

Without any add-on controls, EPA estimates that the CFB boiler should be able to achieve a NO_x emission rate of about 0.15 lb/MMBtu or lower. (Actual operational data on existing CFB boilers suggests to EPA that this value could be much lower. The 0.15 value was chosen by EPA only as a conservative estimate in doing this cost analysis.) Using this uncontrolled emission rate as a baseline, the total cost effectiveness for the SCR/reheat system only, considering the cost of reheat fuel, is calculated as follows:

Emission reduction going from baseline to SCR controlled emissions:

(0.15 lb/MMBtu – 0.015 lb/MMBtu) x (1,445 MMBtu/hr) x
(8,760 hr/yr)(0.9) (1 ton/2,000 lb) = **769 tons/year**

The average cost per ton for NO_x reductions, considering only distillate fuel costs when considering the additional NOx that would be generated by burning distillate fuel:

($12,411,476 / yr) / (769 - 62 ton/yr) = **$17,555/ton**

The incremental cost of going from SNCR to SCR, considering only the distillate fuel costs is calculated as follows:

($12,411,476 / yr) / (370 ton/yr) = **$33,545 /ton**

The incremental cost going from SNCR to SCR, considering only the distillate fuel costs, and considering the additional emissions caused by reheat for SCR, is calculated as follows:

($12,411,476 / yr) / (370 - 62 ton/yr) = **$40,297 /ton**

EPA concludes that the economic impacts associated with a cost of more than $40,000 per ton of pollutant removed justify elimination of SCR as the top control option. Both the total cost effectiveness and incremental cost effectiveness can be considered cost-prohibitive for BACT. In addition, if capital, installation, and other operational costs for both the SCR and reheat system were considered, the above cost values would increase significantly.

In summary, comment #4.c.(5) has not resulted in any change to the permit, since SCR has still been eliminated for cost reasons; however, the Statement of Basis has been changed to reflect the revised NO_x analysis for SCR described above.

Comment #4.c.(6): Further, commenters asserted, in determining whether the costs for SCR are reasonable, the costs must be compared to the costs other coal-fired electric utility boilers have had to bear for NO_x control under BACT determinations. Commenters argued that it is not appropriate to compare SCR to the cost of SNCR, which is less effective than SCR in reducing NO_x.

Response #4.c.(6): Disagree. Commenters do not cite specific coal-fired electric utility boilers the Deseret Power WCFU should be compared to, as far as the costs of NO_x BACT; however, EPA assumes the commenters mean those facilities that have had to bear the costs of installing SCR. To EPA's knowledge, the only coal-fired electric utility boilers that have installed, or will be installing, SCR based on a BACT determination are for pulverized-coal units. Presently, EPA does not know of any CFB boilers that have installed SCR, or that have been required to install SCR, based on a BACT determination, nor have commenters provided any such information.

Determination of whether a control alternative can be eliminated in step four of the top-down BACT analysis involves a demonstration that "circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously." *In re Maui Electric Co.*, 8 E.A.D. 1, 6 (EAB 1998) (internal quotations omitted). Clearly, the fact that Deseret Power's WCFU is a CFB boiler, fired on high-ash waste coal, is a distinguishing feature that creates far different flue gas characteristics and unacceptably high particulate loading to an SCR system that would be installed upstream of the particulate control device, compared to those pulverized coal boilers that have installed SCR systems, or are required to install SCR systems based on a

BACT determination. These differences were explained on page 32 of the draft Statement of Basis.

EPA also disagrees with the commenters' claim that EPA inappropriately compared the cost effectiveness of SCR to SNCR. In step one of the top-down BACT analysis, both the average cost effectiveness of a control option and the incremental cost effectiveness between dominant control options can be calculated. *In re General Motors Inc.*, PSD Appeal No. 01-30, slip op. at 26 (EAB March 6, 2002). While EPA believes it is appropriate to calculate the incremental cost effectiveness of SCR, EPA did not rely on this cost alone. EPA also calculated the average cost effectiveness and found that cost was also high.

In summary, comment #4.c.(6) has not resulted in any change to the permit or Statement of Basis.

Comment #4.c.(7): Commenters asserted that if EPA determines that SCR can be eliminated, after revising the BACT review in light of comments above, then its evaluation of SNCR and the associated NO_x emission limit must be based on the maximum degree of emission reduction achievable with SNCR. Commenters asserted that SNCR should be able to reduce NO_x emissions by at least 50%, while EPA's proposed 0.080 lb/MMBtu NO_x emission limit for SNCR reflects a 47% NO_x reduction. Commenters concluded that a 50% NO_x reduction with SCNR would equate to an emission limit of 0.075 lb/MMBtu, or even lower, considering that EPA believes the 0.15 lb/MMBtu uncontrolled NO_x emission rate is an overestimate. (Commenters cited the draft Statement of Basis at 34-35.)

Response #4.c.(7): Disagree. EPA believes going from 0.075 to 0.08 is justified in order to provide a margin of compliance, and it is consistent with the BACT limits for other sources listed on page 37 of the draft Statement of Basis. The margin of compliance includes a reasonable safety factor that would permit Deseret to achieve compliance on a consistent basis.

The Environmental Appeals Board has recognized that permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis. (See *In re Three Mountain Power*, 10 E.A.D. 39, 53 (EAB, May 30, 2001) and *In re Masonite Corp.*, 5 E.A.D. 551, 560-61 (EAB 1994). See also *In re Knauf Fiber Glass, GmbH*, 9 E.A.D. 1, 15 (EAB, Mar. 14, 2000). ("There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor. …The inclusion of a reasonable safety factor in the emission limitation calculation is a legitimate method of deriving a specific emission limitation that may not be exceeded.")

Comment #4.c.(7) has not resulted in any change to the permit or Statement of Basis.

Comment #4.c.(8): Commenters stated that EPA pointed out to Deseret in its July 8, 2005 letter that there are several other proposed CFB boilers using SNCR with proposed NO_x emission limits of 0.07 lb/MMBtu, including the Estill County Energy Partners Project in Kentucky, the Kentucky Mountain Power Project in Kentucky and the River Hill project in Pennsylvania. As EPA commented to Deseret, the Estill County project is most similar to Bonanza in size and coal quality, and thus Deseret should be able to meet a similar limit at the Bonanza WCFU. Although Deseret later pointed out that no PSD permit had been issued for the Estill County project yet, that does not negate the point that the owners/operators proposed a 0.07 lb/MMBtu NO_x limit for their facility. Thus the NO_x BACT analysis for SNCR should be evaluated using a lower NO_x limit, in the range of 0.07 to 0.075 lb/MMBtu to ensure that the limit reflects the maximum degree of NO_x reduction that can be achieved.

Response #4.c.(8): Disagree. See discussion on page 38 of the draft Statement of Basis for our analysis and consideration of permits with limits of 0.07 lb/MMBtu. The Estill County project was eliminated from consideration because the permit application is no longer being actively processed. No draft permit was issued for the Estill County project and no BACT determination for NO_x was proposed by the permitting agency.

EPA inadvertently omitted the Kentucky Mountain Power Project (KMPP) from the table on page 37 of the draft Statement of Basis ("Summary of Recent CFB Projects Permitted or Proposed: NOx Emission Rates Using SNCR"). EPA has added KMPP in the final Statement of Basis.

The KMPP permit, issued on May 4, 2001, specifies a NO_x emission limit of 0.07 lb/MMBtu; however, unlike the permit for Deseret's WCFU, the KMPP permit says, at Section D, Condition 3, "The NO_x emission limit of 0.07 lb/MMBTU is waived for the specific SNCR optimization study activity as detailed in Condition 2 above not to extend more than 365 days after the initial compliance demonstration. However, the nitrogen oxide emissions rate shall never exceed 0.10 lb/MMBTU, during or after the SNCR optimization study." (Ref: Page 26 of KMPP permit, available on website at:

http://www.air.ky.gov/NR/rdonlyres/696A8A04-2F29-4338-AD6A-7F6B29252676/0/Final.pdf)

By contrast, the permit for Deseret's WCFU says the final limit is 0.080 lb/MMBtu, with no waiver or provision for raising the limit later. Since Kentucky is willing to waive the initial NO_x emission limit for up to a year while a study is conducted, and adjust it up to as high as 0.10 lb/MMBtu after the study is conducted, EPA discounts to some degree the significance of KMPP's initial emission limit of 0.07 lb/MMBtu.

Comment #4.c.(8) has not resulted in any change to the permit; however, the KMPP permit has been added to the above-mentioned table in the Statement of Basis, along with the explanation above on why EPA discounts to some degree the significance of KMPP's initial emission limit of 0.07 lb/MMBtu.

Comment #4.c.(9): Commenters asserted that the draft permit fails to address BACT requirements for NO_x when Deseret is using "run-of-mine" coal either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine. (Commenters cited condition III.E.2.c. of the draft permit.) As indicated by EPA in correspondence to Deseret Power, BACT needs to be met "for the entire range of operating conditions." Yet, commenters argued, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part. As discussed above, commenters argued, such a BACT limit must be imposed on a 24-hour average basis to ensure the maximum degree of NO_x emission reduction is required when 100% "run-of-mine" coal is being burned.

Response #4.c.(9): Disagree. The authorization to burn run-of-mine coal is not unlimited as implied by commenters, but is restricted in the draft WCFU permit, as follows: Condition III.E.2.b. only allows Deseret Power to burn washed or run-of-mine coal during emergencies when waste coal is not available. For situations other than startup or emergencies, condition III.E.2.c. allows use of run-of-mine coal blended with waste coal in any ratio yielding up to 6,500 Btu/lb heat content. This corresponds to roughly a 50/50 blend. Use of run-of-mine coal for the WCFU, either in lieu of waste coal, or as a blend with waste coal, was evaluated in detail on pages 25-29 of the draft Statement of Basis. The proposed BACT determination for NO_x, as well as for other pollutants, is based on the proposed fuel restrictions in the draft PSD permit, also laid out on page 29 of the draft Statement of Basis.

In summary, comments #4.c.(1) through (9) have not resulted in any changes to the permit. However, the Statement of Basis has been changed as follows:

(1) Added a list of additional NOx control options from the Nov. 1999 EPA Technical Bulletin that were not already addressed in the draft Statement of Basis, along with an explanation of why each option was eliminated in the top-down BACT evaluation for Deseret's WCFU,

(2) Revised the cost analysis for SCR, to reflect a lower NO_x emissions rate achievable with SCR than 0.04 lb/MMBtu, and

(3) Added the Kentucky Mountain Power Project to the list of CFB projects with permitted NOx emission rates of 0.07 lb/MMBtu, along with an explanation of why EPA discounts to some degree the significance of KMPP's initial emission limit of 0.07 lb/MMBtu.

4.d -- Total PM/PM_{10}:

Comment #4.d.(1): One group of commenters asserted that EPA's proposed emission limit for total PM/PM_{10} does not reflect BACT. Commenters noted that EPA has proposed a limit for total PM/PM_{10} of 0.03 lb/MMBtu, on a 30-day rolling average. However, commenters argued, as shown in the data provided by EPA in its Statement of Basis, this limit does not reflect the maximum degree of reduction that can be achieved.

Specifically, commenters noted, EPA identifies several other CFB boilers with similar pollution controls as proposed for the Bonanza WCFU with lower total PM/PM_{10} limits. (draft Statement of Basis at 57.) Six of the eight CFB boiler permits reviewed by EPA had lower total PM limits than the proposed 0.03 lb/MMBtu. Three of the eight permits reviewed had limits on total PM of 0.012 lb/MMBtu. Commenters argued that EPA readily discounted these emission limits, but without any review of the specific details behind these emission limits (such as how the sources calculated these emission limits). (draft Statement of Basis at 58.)

Commenters further stated that while EPA did not discount the total PM emission limits of the three proposed facilities in Region 8 (Highwood, Gascoyne, and South Heart), which ranged from 0.0232 lb/MMBtu – 0.026 lb/MMBtu, EPA did not ultimately find that the methodology consistently used by these three facilities for calculating condensible PM emissions was appropriate for the Bonanza WCFU and instead allowed Bonanza's overestimate of ammonium sulfate to dictate the level of the total PM BACT limit. (draft Statement of Basis at 55-56.)

Response #4.d.(1): Disagree. EPA's calculated estimate is consistent with other projects cited in the draft Statement of Basis, not with Deseret's original calculation. As explained in the draft Statement of Basis, EPA found that Deseret's calculations of condensible emissions were not consistent with other permit applicants. "Consequently, EPA did a mass balance calculation that assumed all of the ammonia slip coming out of the CFB combustor unit (i.e., immediately downstream of SNCR controls) would react with sulfuric acid to form ammonium sulfate. This would occur upstream of the dry scrubber and baghouse. EPA also assumed 85% control of ammonium sulfate by the dry scrubber and baghouse. *These assumptions were consistent with analyses in permit applications reviewed by EPA for other CFB boiler projects.* EPA's calculation yielded an emission estimate of 0.0036 lb/MMBtu for ammonium sulfate. This was about one-fifth of Deseret Power's estimated emission range of 0.014 to 0.0209 lb/MMBtu." (emphasis added) (draft Statement of Basis at 56)

Federal PSD rules at 40 CFR 52.21 pertaining to BACT determination do not require EPA to review the specific details of how emission limits were calculated at other facilities. The other facilities (listed on pages 57-58 of the draft Statement of Basis) are only somewhat similar to the proposed WCFU. As explained in the Statement of Basis, in selecting an initial limit of 0.03 lb/MMBtu for total PM/PM_{10} at the WCFU (including condensible PM), EPA relied to a large extent on its own emission calculations specific to the WCFU, for individual components of condensible PM.

Comment #4.d.(1) has not resulted in any change to the permit or Statement of Basis.

Comment #4.d.(2): Commenters further alleged that the actual stack test data for similar sources are lower than EPA's proposed total PM BACT limit, with results ranging from 0.004 lb/MMBtu to 0.023 lb/MMBtu using EPA Method 202. (draft Statement of Basis at 59.) Thus, commenters argued, the majority of the data provided by EPA in its draft Statement of Basis indicate that its proposed total PM/PM_{10} BACT limit does not reflect the maximum degree of emission reduction that can be achieved as required by the definition of BACT. While EPA's proposed 0.03 lb/MMBtu emission limit incorporates a "margin of safety," the margin of safety is too lenient.

Response #4.d.(2): Disagree. The draft Statement of Basis (at page 59) actually refers to 0.03 lb/MMBtu as "an initial emission limit that EPA believes can reasonably be achieved (with appropriate margin of compliance)…" EPA does not consider the margin in this case to be too lenient. EPA's rationale for proposing an initial permit limit of 0.03 lb/MMBtu is explained in great detail on pages 54-64 of the draft Statement of Basis.

As explained in the draft Statement of Basis, EPA did evaluate stack testing data from other facilities, but there are minimal data on condensible PM emissions from CFB units, and no data for CFBs burning bituminous waste coal. The proposed permit limit of 0.03 lb/MMBtu is largely based on emission calculations that are specific to Deseret Power's proposed WCFU, as described on page 56 of the draft Statement of Basis. No numerical margin of compliance was incorporated into the calculation of 0.03 lb/MMBtu as an initial limit. Rather, EPA considers the "margin of compliance" to be the ability to revise the limit upward, to no more than 0.045 lb/MMBtu, if stack testing results show that a limit of 0.03 lb/MMBtu is not achievable.

Although EPA is establishing a total PM/PM_{10} emissions limit in the final WCFU permit that includes condensible PM consistent with the draft permit, we must note that EPA has recently acknowledged the concerns regarding the availability and implementation of test methods for condensible PM. As a result of these concerns, EPA's recent $PM_{2.5}$ implementation rule for State Implementation Plans has adopted a transition period during which EPA will assess possible revisions to available test methods and allow time for States to update emissions inventories. 72 Fed. Reg. 20586, 20650 (Apr. 25, 2007). EPA is currently considering whether it should also establish a similar transition period in its forthcoming $PM_{2.5}$ implementation rule for the New Source Review permitting program. Notwithstanding this ongoing assessment, EPA has decided to retain the proposed total PM/PM_{10} emissions limit to accommodate the request of the permit applicant that we not allow that rulemaking action to delay the completion of this permit.

Comment #4.d.(2) has not resulted in any change to the permit or Statement of Basis.

Comment #4.d.(3): In addition, commenters asserted, due to the deficiencies in EPA's 0.03 lb/MMBtu BACT determination for total PM/PM_{10}, the permit must not allow for an even further relaxation of this limit up to 0.045 lb/MMBtu. Commenters said this upper bound limit is unjustified as BACT.

Response #4.d.(3): Disagree. As explained on pages 58-64 of the draft Statement of Basis, due to the inherent uncertainty with setting a limit for total PM/PM_{10} that includes condensible PM at a CFB unit burning bituminous waste coal, EPA believes that 0.045 lb/MMBtu is an appropriate upper bound for possible adjustment of the limit. In describing its engineering calculation to estimate the amount of condensible PM that would be emitted from the WCFU, EPA pointed out the uncertainties in the calculation, due to the complexities in the chemical reactions taking place from fuel combustion. (draft Statement of Basis at 57.) As also explained in the draft Statement of Basis, there are only minimal stack test data for somewhat similar projects.

EPA believes the provision to adjust the limit upward later, to no more than 0.045 lb/MMBtu, pending EPA review of stack test results, is warranted and consistent with EPA's approach in other similar situations (e.g., AES Puerto Rico, cited on page 63 of the draft Statement of Basis and cited again below).

Comment #4.d.(3) has not resulted in any change to the permit or Statement of Basis.

Comment #4.d.(4): Commenters asserted that if Deseret Power obtains stack test data indicating that the total PM/PM_{10} BACT limit cannot reasonably be complied with, EPA can propose a revised total PM_{10} limit at a later time. Such a revised limit must be subject to public review and opportunity for comment.

Response #4.d.(4): Disagree. As explained on pages 54-64 of the draft Statement of Basis, EPA proposed an initial emission limit for total PM/PM_{10} of 0.03 lb/MMBtu, including condensible PM, based on EPA emission calculations specific to the proposed WCFU, as well as based on limited stack testing data for somewhat similar facilities. As mentioned in response #4.d.(3) above, EPA explained in the draft Statement of Basis the inherent uncertainty with setting a limit for total PM/PM_{10} that includes condensible PM at a CFB unit burning bituminous waste coal, due to the complexities in the chemical reactions taking place from fuel combustion. (draft Statement of Basis at 57.)

The Environmental Appeals Board (EAB) has recognized that "use of an adjustable limit, constrained by certain parameters, and backed by a worst case air quality analysis, is a reasonable approach." *In re AES Puerto Rico*, 8 EAD 324, 349 (1999).

As explained on page 63 of the draft Statement of Basis, EPA proposed to allow in the permit that the limit could be adjusted upward, to no more than 0.045 lb/MMBtu, pending EPA review of stack test results at the WCFU. This sets an upper bound on the possible adjustment. EPA stated in the draft permit itself that "[b]ecause condensible

particulate matter emissions from CFB boilers have not been widely quantified, there is a possibility that the actual condensible portion of particulate matter would cause the emission limit of total PM/PM_{10} to be exceeded. In the event the Permittee cannot meet that limit because of condensible particulate matter, EPA may adjust the emission limit to a level not to exceed 0.045 lb/MMBtu, pending EPA's review of stack test results at the CFB boiler." (draft WCFU permit at page 7.) The range of possible emission limits is therefore constrained between 0.03 lb/MMBtu and 0.045 lb/MMBtu, and was subject to public review and comment.

As listed on page 128 of the draft Statement of Basis, the WCFU emission rate of total PM/PM_{10} used for modeling of ambient air quality impact was 9.47 grams per second. This rate is equivalent to 0.052 lb/MMBtu multiplied by the WCFU maximum design heat input capacity of 1,445 MMBtu/hr. Even if the BACT limit of 0.03 lb/MMBtu is adjusted to the upper bound in the draft permit of 0.045 lb/MMBtu, the limit is still lower than the emission rate used for modeling. Therefore, the range of 0.03 to 0.045 lb/MMBtu is backed by a worst case air quality analysis, and at the upper bound of 0.045 lb/MMBtu, the NAAQS and PSD increment will still be protected.

In summary, EPA believes that the possible future adjustment of the total PM/PM_{10} emission limit, within the parameters specified in the permit, is a "reasonable approach" as recognized by the EAB. The range of possible adjustment was subject to public review and opportunity for comment, therefore does not require additional public review and opportunity for comment later. Comment #4.d.(4) has not resulted in any change to the permit or Statement of Basis.

Comment #4.d.(5): Commenters concluded that until such time as the limit is revised, the evidence provided by EPA indicates that the proposed total PM/PM_{10} BACT limit is too high.

Response #4.d.(5): Disagree, as explained on pages 54-64 of the draft Statement of Basis, and as explained in responses #4.d.(1) through #4.d.(3) above. Comment #4.d.(5) has not resulted in any change to the permit or Statement of Basis.

Comment #4.d.(6): Commenters further stated that the draft WCFU permit also fails to address BACT requirements when Deseret Power is using"run-of-mine" coal either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine (as allowed by Condition III.E.2.c. of the draft permit). As indicated by EPA in correspondence to Deseret Power, BACT needs to be met "for the entire range of operating conditions." (Ref: April 7, 2006 e-mail from Mike Owens, EPA Region 8, to Ed Thatcher, Deseret Power.) Yet, commenters said, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part. Commenters argued that, as discussed above, such a BACT limit must be imposed on a 24-hour average basis to ensure the maximum degree of PM emission reduction is required when 100% "run-of-mine" coal is being burned.

Response #4.d.(6): Disagree. See draft Statement of Basis at page 64: "As explained earlier in this Statement of Basis, for the proposed WCFU, Deseret Power will be permitted to use coal from their Deserado mine, consisting of either waste coal alone, or else a blend of waste coal and ROM coal yielding heat content of up to 6,500 Btu/lb. For reasons explained above, EPA believes the proposed BACT emission limit of 0.03 lb/MMBtu on a rolling 30-day average, for total PM/PM_{10}, will represent BACT for coal from the Deserado mine with heat content of up to at least 6,500 Btu/lb, and will ensure a continued high degree of PM emission control efficiency." Comment #4.d.(6) has not resulted in any change to the permit or Statement of Basis.

In summary, comments #4.d.(1) through (6) have not resulted in any changes to the permit or Statement of Basis.

4.e -- Visible Emissions:

Comment #4.e: A group of commenters asserted that EPA failed to evaluate and impose a BACT limit for visible emissions (VE), and that the BACT analysis for the Bonanza WCFU must include a visible emission limit reflective of BACT for the source.

Commenters argued that the definition of BACT at 40 CFR 52.21(b)(12) specifically indicates that BACT includes a "visible emission limitation." Commenters noted that in the draft Statement of Basis, EPA indicated that, because EPA is proposing use of a PM continuous emission monitoring system (CEMS), "EPA does not consider it necessary to also propose an opacity limit as part of BACT for total filterable particulate." (draft Statement of Basis at 47.) Commenters argued that EPA's reasoning is flawed for several reasons, described in comments #4.e.(1) through (5) below:

Comment #4.e.(1): Commenters argued that the definition of BACT in the Clean Air Act and associated federal regulations specifically mandate that BACT include a visible emission (or opacity) limitation. There are no exemptions provided for in the statutory or regulatory definition. Thus, commenters concluded, EPA is without legal authority to decide not to impose an opacity limit because it is requiring PM CEMS for the PM limit.

Response #4.e.(1): Disagree. EPA does not view the phrase "visible emission standard," in the BACT definition at 40 CFR 52.21(b)(12), as an emission limit that all PSD permittees must meet, nor as implying that a visible emission (VE) and/or opacity limit must be included in all PSD permits. However, while these limits are not required under BACT, permitting authorities have the discretion to include them in PSD permits in order to ensure compliance with BACT emission limitations.

In fact, the Circuit Court of Appeals for the District of Columbia (DC Circuit) found that visible emission limitations were properly included in PSD permits as "one such means of measuring and limiting emissions" under BACT, but stated that "EPA's inclusion of visible emission standards (among others) to be used to determine compliance with BACT sets no single standard that all PSD permittees must meet." *Alabama Power v. Costle*, 636 F.2d 323, 408 (D.C. Cir. 1979) (emphasis added). Instead, the DC Circuit found that permitting authorities "may exercise reasonable discretion" to include opacity/VE limits in BACT for a particular facility. Id. at 409. The Environmental Appeals Board has also found that such limits are not a requirement of PSD program permitting. *See Knauf Fiber Glass*, 8 E.A.D. 121, 172 (1999) (finding that opacity limits are "not a requirement of the federal PSD program").

Accordingly, in order to avoid confusion regarding the opacity limit contained in the "PSD BACT Emission Limits" section of the permit, EPA notes that the opacity limit is included for demonstrating continued proper operation and maintenance of the materials handling baghouses, not because it is required under BACT. The permit title section III.D has been amended to indicate the section includes limits in addition to BACT.

Comment #4.e.(1) has not resulted in any substantive change to the permit or Statement of Basis.

Comment #4.e.(2): Commenters argued that the Particulate Matter Continuous Emission Monitoring System (PM CEMS), required by the draft permit, will only measure filterable particulate matter, while opacity measures all particulate matter that may block the transmission of light exiting the stack including condensible particulate matter. While compliance with the total particulate matter limit must be demonstrated on a rolling 30-day average basis at the Bonanza WCFU (Condition III.D.1.a. of the draft permit), this compliance determination will be based on a once-per-year stack test of the total PM emission rate (Condition III.I.4.b of the draft permit). Commenters concluded that an opacity limit that can be continuously monitored will provide a much needed additional assurance that the total particulate matter emission limits are being complied with continuously.

Response #4.e.(2): Disagree. While it is true that PM CEMS only measures filterable particulate matter, EPA believes that opacity monitoring at Deseret Power's WCFU, as an addition to requiring a PM CEMS calibrated according to 40 CFR 60, Appendix B, Performance Specification 11, would be ineffective for assuring compliance with emission limits for either filterable PM or total PM.

Opacity monitoring can be useful as a surrogate for direct measurement of particulate emissions. However, EPA does not consider it useful for assuring compliance with PM emission limits where those limits are extremely low. The proposed emission limit for Deseret Power's WCFU for total PM/PM_{10} is 0.03 lb/MMBtu. This limit is based on a filterable PM/PM_{10} emission limit of 0.012 lb/MMBtu, added to projected emissions of no more than 0.018 lb/MMBtu for condensable PM. These emission limits are so low that EPA believes it highly improbable, if not impossible, that any form of existing opacity monitor could reliably detect opacity at levels that would correspond to these limits. Moreover, given the sensitivity of the PM CEMS, elevated emissions would be detected by PM CEMS well in advance of detection via a Continuous Opacity Monitoring System (COMS), or via a Method 9 or Method 22 visible emissions observation. Further, opacity only provides data from a subset of all particles, namely those particles whose size is roughly the same wavelength as visible light.

A status report prepared for EPA on PM CEMS, dated February 12, 1997 (available at http://www.epa.gov/ttn/emc/cem.html, labeled on website as "PM CEMS Demo. Test, Status Report 4 (Adobe format)," with website posting date of 7/31/97) in support of proposed revised regulations for hazardous waste combustors (HWC), states (in the Introduction, as quoted below) that opacity monitors are insensitive at filterable PM concentrations below 45 mg/dscm. For coal combustion, this is equivalent to about 0.04 lb/MMBtu. (The proposed total PM/PM_{10} emission limit for Deseret Power's WCFU, cited above, is lower than this.) The Introduction states:

EPA in the past has relied on opacity monitors as a form of surrogate-PM monitoring to indicate compliance with a PM standard. This approach involved a continuous opacity monitor to demonstrate compliance with a separately-enforceable opacity limit approximately aligned with, or near, the PM emission limit. However, this approach has a serious limitation relative to the proposed HWC rule, because of poor correlation between opacity and PM at low PM concentrations near the proposed PM emission limit of 69 mg/dscm (at 7 % O2).

EPA recognizes that there are two inherent problems with the opacity/PM approach: 1) the general concern about the stability of any opacity/PM correlation, which is strongly dependent on particle size distribution and composition, and 2) the specific concern about the insensitivity of opacity monitors typically below PM levels of about 45 mg/dscm (at 7 % O2).

Consequently, opacity monitors would not be sufficient because to maintain compliance with 69 mg/dscm, facilities would generally need to operate near 35 mg/dscm. Thus, emissions would typically be below the detection limits of opacity monitors most of the time. While normal emission levels below the detection limits of CEMS are acceptable, facilities often desire the detection limit to be one-tenth of the emission limit. This gives sufficient warning of how emissions are changing before the emission limit is approached, and allows the facility, based on CEMS readings, to change operations as necessary to be in compliance.

If possible, EPA desires a quantitative, continuous measure of PM mass concentrations rather than opacity. Based on surveys and preliminary testing, EPA has recently determined that CEMS do exist that do this: beta gauges and light scattering based CEMS. These CEMS rely on calibration/certification of the device by manual gravmetric measurements. Therefore, EPA is proposing use of CEMS based on the availability of these newer technologies and a related Draft CEMS Performance Specification for monitoring PM mass concentration. EPA believes that such monitoring is feasible and that opacity monitoring has borderline sensitivity relative to the proposed PM emission limit. The newer technology PM CEMS can give a real-time quantitative measure of low PM concentrations while opacity monitors cannot.

(Ref: Status Report No. IV, Particulate Matter CEMS Demonstration, prepared by Energy and Environmental Research Corporation, EPA Contract 68-D2-0164, Work Assignment 4-02, February 12, 1997.)

This same reasoning is reflected in the recent revisions to Subpart Da of New Source Performance standards (40 CFR 60). The revised Subpart Da exempts facilities from ongoing opacity monitoring where PM CEMS is installed and used.

Further, the proposed emission control technique for condensable PM at Deseret Power's WCFU is a combination of alkali injection, dry SO_2 scrubbing and a fabric filter baghouse. (Draft Statement of Basis at 50.) Each of these control techniques will be

installed and used to comply with other emission limits in the permit (alkali injection for NO_x control, dry SO_2 scrubbing for SO_2 control, and a fabric filter baghouse for filterable PM control). The permit requires compliance with these three other emission limits to be tracked continuously via CEMS. (Draft WCFU permit at pages 16-17, conditions III.I.4.a and III.I.4.c.) This continuous monitoring, in addition to annual stack tests required in the permit for condensable PM, is considered by EPA to be sufficient for ensuring good control of the both the condensable PM portion and the filterable PM portion of total PM. EPA does not agree with commenters that opacity monitoring "will provide a much needed additional assurance that the total particulate matter emission limits are being complied with continuously."

In summary, comment #4.e.(2) has not resulted in any change to the permit. However, the Statement of Basis has been revised to included the expanded explanation above on why EPA does not consider an opacity limit or opacity monitoring to be necessary at the WCFU.

Comment #4.e.(3): Commenters argued that a limitation on visible emissions serves as an indicator of proper operation and maintenance (O&M) of all pollution control equipment.

Response #4.e.(3): Disagree. EPA recognizes that opacity monitoring can be useful as an indicator of proper baghouse O&M; however, as explained in response #4.e.(2), the proposed emission control technique for condensable PM at Deseret Power's WCFU is a combination of alkali injection, dry SO_2 scrubbing and a fabric filter baghouse, not just a baghouse. EPA considers CEMS for NO_x, SO_2 and PM to be far more useful than opacity monitoring for ensuring good control of condensable PM at Deseret Power's WCFU. Further, the fact that opacity monitoring can be useful as an indicator of proper baghouse O&M does not mean it is necessarily useful for ensuring compliance with PM emission limits. As explained in response #4.e.(2), in this case EPA does not believe it is useful. Comment #4.e.(3) has not resulted in any change to the permit or Statement of Basis.

Comment #4.e.(4): Commenters argued that compliance with both the filterable and total PM/PM_{10} limits is based on a rolling 30-day average basis, whereas compliance with opacity BACT limits are based on a six-minute averaging time. Thus, commenters concluded, the 30-day rolling average filterable PM limit measured with PM CEMS is not an adequate replacement for a six-minute average opacity BACT limit.

Response #4.e.(4): Disagree. See responses #4.e.(2) and #4.e.(3).

Comment #4.e.(5): Commenters argued that with a fabric filter baghouse for PM_{10} control, an opacity BACT limit should be "at least 10%." Commenters noted that the recently permitted Sevier CFB power plant in Utah is subject to a 10% visible emissions limit. The River Hill Power Company proposed CFB power plant in Pennsylvania is also subject to a 10% opacity limit. Similarly, the Gascoyne CFB facility in North Dakota will also be subject to a 10% opacity BACT limit. Commenters also

noted that the permit for the Longview power plant in West Virginia, which will utilize a pulverized coal boiler, requires PM CEMS and imposes a 10% opacity BACT limit.

Response #4.e.(5): Disagree. Commenters have not presented any evidence that a 10% opacity limit would have any correlation with the proposed total PM/M_{10} emission limit of 0.03 lb/MMBtu for Deseret Power's WCFU. Further, as explained in response #4.e.(2), EPA believes it highly improbable, if not impossible, that any form of existing opacity monitor could reliably detect opacity at levels that would correspond to PM emission rates as low as 0.03 lb/MMBtu. EPA has also found there is poor correlation between opacity and PM at such low PM concentrations. Comment #4.e.(5) has not resulted in any change to the permit or Statement of Basis.

Comment #4.e.(6): Commenters concluded that EPA must include an evaluation of opacity BACT in its Statement of Basis and must impose a visible emission limit on the Bonanza WCFU that reflects the maximum degree of reduction achievable. Further, to ensure compliance on a continuous basis, commenters concluded that a continuous opacity monitoring system (COMS) must be required.

Response #4.e.(6): Disagree. See responses #4.e.(1) through (5) above.

In summary, comments #4.e.(1) through (6) have not resulted in any change to the permit. However, the Statement of Basis has been revised, to included the expanded explanation provided in response #4.e.(2), on why EPA does not consider it necessary to impose an opacity limit or opacity monitoring at the WCFU.

5. MEETING BACT LIMITS ON A CONTINUOUS BASIS AND MEETING ENFORCEABILITY CRITERIA

Comment #5:

One group of commenters stated that all BACT limits must be met on a continuous basis and must meet enforceability criteria, but that the draft Bonanza WCFU permit does not adequately address EPA requirements for including such provisions.

5.a – Meeting BACT Limits on a Continuous Basis:

Comment #5.a.(1): Commenters cited from the draft 1990 NSR Workshop Manual that "BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in lb/MMBtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds per hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements)." (NSR Workshop Manual at B.56). Commenters argued that EPA did not propose BACT limits consistent with these criteria.

Specifically, commenters argued, with respect to all of the emission limits, there must be pound per hour emission caps established, in addition to lb/MMBtu limits, that must be reflective of BACT and consistent with what is modeled to show compliance with the NAAQS, PSD increments, and air quality related values. Commenters stated the NSR Workshop Manual indicates that it is best to express emission limits in two different ways, "with one value serving as an emissions cap (e.g., lb/hr) and the other ensuring continuous compliance at any operating capacity (e.g., lb/MMBtu)." (NSR Workshop Manual at H.5. See also *In re Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4 & 99-5, Decided June 22, 2000, at 220-225.)

Commenters noted that EPA only proposed BACT limits in terms of lb/MMBtu, and EPA did not evaluate or propose BACT limits in terms of lb/hr. While EPA did propose lb/hr "modeling limits" for SO_2 and total PM_{10} (Section G. of the draft permit), commenters stated that these modeling limits are not reflective of BACT for the Bonanza WCFU. Commenters argued that at full heat input capacity, the 3-hour average 872 lb/hr SO_2 modeling limit is equivalent to 0.6 lb/MMBtu, which would be only 87% SO_2 removal from worst case uncontrolled SO_2 emissions. The 24-hour total PM_{10} modeling limit of 75.4 lb/hr is equivalent to 0.052 lb/MMBtu at full heat input capacity – which, commenters noted, is greater than the maximum level EPA has proposed the total PM_{10} limit could be raised to. Commenters concluded that these modeling limits clearly do not reflect BACT for these pollutants. Commenters also asserted that EPA failed to propose BACT limits in terms of lb/hr for NO_x, CO, or H_2SO_4.

Further, commenters argued, the averaging time of the BACT emission limits must be "of a short-term nature" and must be consistent with the averaging time of the short term NAAQS and PSD increments, including a 24-hour averaging time for PM_{10}

limits, an 8-hour averaging time for CO limits, and an 8-hour averaging time for VOC limits, as well as the 24-hour averaging time for the pollutants modeled in the visibility modeling. (NSR Workshop Manual at H.5.) Yet, commenters stated, EPA's proposed lb/MMBtu BACT limits for SO_2, NO_x, CO, and PM_{10} for the Bonanza WCFU are all based on rolling 30-day averages. Commenters concluded that, while EPA has proposed short term average emission limits for SO_2 and PM_{10} as modeling limits, these limits are not reflective of BACT for these pollutants.

Response #5.a.(1): Partially disagree. EPA agrees that a shorter-term limit than rolling 30-day should be specified for filterable PM. As discussed below, EPA has changed the averaging time to daily in the final permit.

EPA does not agree, however, that emission limitations for purposes of PSD increment protection and NAAQS protection (such as the lb/hr limits that EPA included in the draft permit, labeled "modeling limits") have to reflect BACT, nor that BACT limits must always include lb/hr limits and correspond to all averaging times of the PSD increments and NAAQS. As explained below in response #5.a.(2), EPA included Federally enforceable "modeling limits" in the draft permit specifically for ensuring compliance with the NAAQS and increments under 40 CFR 52.21(k). The rolling 30-day emission limits in lb/MMBtu in the draft permit reflect BACT, pursuant to 40 CFR 52.21(j)(3). As explained in detail on pages 30 through 90 of the draft Statement of Basis, for each pollutant for which a BACT determination is required by PSD rules, the BACT emission limit in lb/MMBtu for the WCFU was set at a level sufficiently stringent to reflect optimal emission control performance on a continual basis.

The "modeling limits" for the WCFU were established under different provisions of PSD rules than the BACT limits. As explained on page 138 of the draft Statement of Basis, "EPA interprets the PSD rules at 40 CFR 52.21(k) to require that emission limits be included in PSD permits ('modeling limits') consistent with emission rates used in dispersion modeling for ambient impacts, unless it would be physically impossible for the proposed source or modification to emit at a greater rate (i.e., maximum potential uncontrolled emissions). This requirement is *in addition to* the requirement under §52.21(j)(2) to establish BACT emission limits." [emphasis added; citation in the draft Statement of Basis should have been to §52.21(j)(3); this typographical error was corrected in the final Statement of Basis.]

EPA has proposed modeling limits in lb/hr corresponding to the emission rates assumed in dispersion modeling for cumulative ambient impacts of the proposed WCFU and all existing emitting units in the vicinity of the project. (The only exception is NO_x, for which, as explained in the draft Statement of Basis, EPA determined that the BACT limit could also serve as a modeling limit, without need to propose a separate modeling limit for NO_x in lb/hr.)

These modeling limits are enforceable emission limits in the permit, and were established based on worst-case operating scenarios used for dispersion modeling. For example, the modeling limits for 3-hour and 24-hour SO_2 are based on a cold startup,

which is the worst-case SO_2 emission scenario that might be expected, not optimal emission control performance on a continual basis. This worst-case scenario is described on page 138 of the draft Statement of Basis and was the scenario used for dispersion modeling for demonstrating PSD increment protection and NAAQS protection.

Although the permit does not list any lb/hr emission limits as BACT limits, the lb/MMBtu BACT limits in the permit, when multiplied by the maximum heat input capacity of the CFB boiler, are mathematically equivalent to lb/hr values. The draft WCFU permit says, on page 5, that the "Approved Installation" includes "One circulating fluidized bed boiler, *maximum heat input capacity not to exceed 1,445 MMBtu/hr*, designed for firing on waste coal." [emphasis added] As stated above, the lb/MMBtu limits in the permit were set at a level sufficiently stringent to reflect optimal emission control performance on a continual basis.

Furthermore, during periods of low boiler load, lb/hr emission caps would not necessarily reflect BACT. In a letter to Deseret Power dated June 22, 2005 (included in the Administrative Record for issuance of the WCFU permit), EPA questioned whether the lb/hr emission caps proposed by Deseret Power for startup/shutdown (i.e., during periods of low boiler load) could be justified as BACT, in terms of optimal use of the emission control equipment. The emission cap approach was ultimately not used in the permit for startup/shutdown periods. Instead, the permit states, at condition III.I.1, that the BACT emission limits (all expressed in lb/MMBtu) apply at all times, including periods of startup/shutdown.

Contrary to the conclusion implied by commenters, the Steel Dynamics EAB decision does <u>not</u> say PSD permits must include both emission caps (e.g., lb/hr limits) and production-based limits (e.g., lb/MMBtu). Instead, the EAB decision says, on page 225, that the Indiana Department of Environmental Management (IDEM) "…is ordered to explain why the limits it imposed are in lbs/hr (rather than in lbs/hr *and* lbs/ton, or lbs/ton alone), in particular explaining in detail the specific differences (if any) between SDI's proposed mill and the fifteen polled mills that would justify exclusive lbs/hr limits for CO and NO_x." The EAB decision does not preclude the possibility that production-based limits alone, absent lb/hr limits, could constitute BACT.

The Steel Dynamics decision involves considerations specific to the batch-type nature of the steelmaking process, which, as explained in the decision, could warrant lb/hr limits as BACT in some cases. Deseret Power's proposed WCFU is an electric utility generating unit designed to run continuously, not a batch-type operation. PSD rules define BACT as a case-by-case determination. The considerations in the BACT determination for the WCFU are different than for a batch-type steelmaking process, and affect whether or not lb/hr limits are warranted as part of BACT.

EPA Region 8's comments on state permit actions are consistent with the statements above that modeling limits in lb/hr don't necessarily have to reflect BACT, nor that BACT limits must always include lb/hr limits and correspond to all averaging

times of the PSD increments and NAAQS. In commenting to Montana on the draft PSD permit for the Roundup coal-fired electric utility project, EPA Region 8 wrote:

> *Currently the draft permit only contains SO_2 emission limitations on a 30-day rolling average. This approach may be acceptable <u>only</u> if modeling for protection of the short-term NAAQS and PSD increments was based on worst-case hourly SO_2 emissions, rather than on the 30-day emission limitations in the draft permit. At a minimum, we believe the permit action should either establish short-term emission limits in the permit itself, or justify that worst-case hourly SO2 emission limits have been modeled for protection of short-term NAAQS and PSD increments.*
>
> (Ref: Letter from Richard R. Long, EPA Region 8, to Steve Welch, Montana Department of Environmental Quality, December 18, 2002, page 6; emphasis added.)

The letter on Roundup does not say or imply that short-term emission limitations must reflect BACT, but only that short-term limits must be imposed as necessary in the permit to validate the assumptions used in dispersion modeling.

Similarly, in an EPA guideline document, on SO_2 emission limitations in State Implementation Plans (SIPs), the stated purpose of short-term emission limitations is the protection of ambient standards. The document does not say or imply that short-term emission limitations must also reflect BACT:

> *The EPA policy regarding averaging periods for SO_2 SIP emission limitations is to require enforceable limits that protect the short-term (3-hour and 24-hour) NAAQS as well as the annual NAAQS. These emission limitations must be protective with maximum emission scenarios and worst-case meteorological conditions. ... The EPA will not approve an SO_2 SIP with emission limitations based on 30-day averaging, unless the SIP also contains short-term limits established by an approved dispersion modeling analysis. This point is especially important for SO_2 sources that are complying with an NSPS (e.g., subpart Da). Although subpart Da allows 30-day averaging, parameters for evaluating the control system on a short-term basis must also be established for compliance with the NAAQS and PSD increments.*
>
> (Ref: "SO_2 Guideline Document," EPA-452/R-94-008, February 1994, page 6-14, available online at: http://nepis.epa.gov/pubtitleOAR.htm.)

Similarly, a 1986 letter signed by EPA's Assistant Administrator for Air and Radiation, regarding SO_2 SIPs, states the same purpose for short-term emission limitations:

> *EPA has had a long standing policy to require emission limitations to be enforceable on a short-term basis to protect the short-term standard.*

(Ref: Letter from J. Craig Potter, Assistant Administrator for Air and Radiation, US EPA, to Nancy Maloley, Commissioner, Indiana Department of Environmental Management, May 23, 1986, page 1, included in the Administrative Record for issuance of the WCFU permit.)

Again, there is no statement that such limitations must also reflect BACT.

Similarly, a 1986 EPA memorandum states the following:

> *The PSD regulations clearly require that the application of BACT conform with any applicable standard of performance under 40 CFR Part 60 at a minimum. However, this should not be taken to supercede any additional limitations as needed to enable the source to demonstrate compliance with the NAAQS and PSD increments. In the case of sulfur dioxide (SO2), source compliance with the 30-day rolling average emission limit under subpart D(a) does not adequately demonstrate compliance with the short-term NAAQS and PSD increments.*
>
> Ref: Memorandum from Gerald A. Emison, Director, Office of Air Quality Planning and Standards, US EPA, to David Kee, Director, Air Management Division, EPA Region 5, November 24, 1986, page 1, available online at:
>
> http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/shrtterm.pdf

Again, the stated purpose of the short-term emission limitations is the protection of short-term ambient standards. There is no statement that such limitations must also reflect BACT.

With regard to the statement in the 1986 EPA memorandum that "the application of BACT conform with any applicable standard of performance under 40 CFR part 60 at a minimum," EPA notes that the averaging times of the proposed BACT emission limits for the WCFU conform with those in 40 CFR 60, subpart Da, with the exception of filterable PM/PM_{10}, for which the draft WCFU permit specifies a 30-day rolling average, whereas Subpart Da specifies a daily average. To conform with 40 CFR part 60, subpart Da, EPA believes it is necessary to change the averaging time of the BACT limit to daily.

In summary, EPA believes the draft permit for the WCFU includes all short-term (lb/hr) emission limitations that are necessary to protect ambient standards, to the extent required by Federal rules at 40 CFR 52.21(k). EPA also believes the draft permit contains all emission limits necessary to satisfy BACT, as required by Federal rules at 40 CFR 52.21(j)(3), with the exception that EPA believes the averaging time of the BACT limit for filterable PM/PM_{10} should be changed from 30-day rolling to daily, to conform with 40 CFR 60 subpart Da. Therefore, to the extent that commenters suggest shorter-term limits are needed than those in the draft permit, EPA agrees with commenters with regard to PM/PM_{10}.

The final permit reflects this change. Instead of 0.012 lb/MMBtu on a 30-day rolling average, the limit in the final permit is 0.012 lb/MMBtu on a daily average. Monitoring, reporting and recordkeeping requirements in the permit have been changed accordingly. Since this limit is no more stringent than filterable PM/PM_{10} limits at some other new coal-fired projects (e.g., Utah permit ("Approval Order") dated October 15, 2004, for construction of Intermountain Power Unit 3, included in the Administrative Record for issuance of the WCFU permit), EPA believes it is achievable by Deseret Power. The Statement of Basis has been revised accordingly, to reflect a daily average (i.e., a 24-hour block average from midnight to midnight) rather than a 30-day rolling average. Comment #5.a.(1) has resulted in these changes to the permit and Statement of Basis.

Comment #5.a.(2): Commenters noted that EPA's Statement of Basis explains that the lb/hr emission rates used in the modeling analyses reflect short term emission peaks from startups. (draft Statement of Basis at 135.) Commenters asserted that EPA "admitted" that the proposed BACT limits for SO_2 and PM_{10} do not adequately limit short term emissions for compliance with the NAAQS and PSD increments because the BACT limits are based on 30-day rolling averages. (draft Statement of Basis at 136.) Yet, commenters stated, "as acknowledged by EPA in the Statement of Basis," BACT emission limits must be met on a continuous basis, and there are to be no exemptions for startup and shutdown. (draft Statement of Basis at 23.)

In particular, commenters stated, EPA noted in its draft Statement of Basis that the NSR Workshop Manual states (at page B.56) "BACT emission limits or conditions must be met on a continual basis *at all levels of operation*." [emphasis added by commeneters] Yet, commenters argued, EPA's proposed BACT limits violate these principles and essentially provide for startup and shutdown exemptions from BACT by providing such long averaging times for the BACT emission limits.

Response #5.a.(2): Disagree. First, EPA included "modeling limits" in the permit, as a separate set of limits from the BACT emission limits, specifically for ensuring compliance with the NAAQS and PSD increments. (draft Statement of Basis at 138-139). Second, the draft permit does not allow any exemptions from either the BACT limits or the modeling limits for startup/shutdown periods. Section III.I.1 of the draft permit states that "The PSD BACT emission limits in this permit, as well as the modeling limits, *apply at all times, including periods of startup, shutdown and malfunction*." [emphasis added] Moreover, the requirements in the permit for continuous monitoring of emissions of particulate matter, SO_2, NO_x and CO, and accompanying averaging times, are consistent with the concept of continuous compliance identified by the commenters.

As demonstrated by the detailed discussion in the draft Statement of Basis of the BACT determination for each pollutant, the 30-day limits have been set at levels sufficiently stringent as to not allow under-utilization of control equipment. Setting a stringent 30-day limit that applies at all times creates an incentive for the source to limit its duration of startup, shutdown, and malfunction periods in order to preserve any margin of compliance the source might be operating under.

In summary, EPA believes the proposed 30-day average BACT limits (and the limit for filterable PM/PM_{10}, on a daily average in the final permit), in conjunction with continuous emission monitoring, are consistent with the EPA policy that BACT applies at all times and must be met at all levels of operation. EPA also believes that inclusion of modeling limits in the draft permit adequately addresses the commenters' concern about NAAQS and PSD increment protection. Comment #5.a.(2) has not resulted in any change to the permit or Statement of Basis.

Comment #5.a.(3): Commenters further argued that EPA's failure to propose shorter averaging time emission limits reflective of BACT is inconsistent with recently issued permits for coal-fired power plants. Commenters cited the Roundup power plant permit issued by the state of Montana as requiring 24-hour average BACT limits for NO_x and SO_2, and also a 1-hour BACT limit for SO_2. Commenters also cited the Sevier power plant permit issued by the state of Utah as including rolling 24-hour average BACT limits for SO_2, NO_x, PM_{10}, and H_2SO_4. Commenters also cited the Longview power plant permit issued by the state of West Virginia as including a 3-hour average SO_2 BACT limit, 24-hour average NO_x and SO_2 BACT limits, a 6-hour average PM_{10} BACT limit and a 3-hour average H_2SO_4 BACT limit.

Commenters concluded that for all of the above reasons, EPA must revise its proposed BACT limits for the Bonanza WCFU to require shorter averaging times consistent with the NAAQS, PSD increments, and air quality related values standards and to also set lb/hr emission limits reflective of BACT, with compliance being monitored by continuous emission monitoring systems as proposed by EPA for SO_2, NO_x, and PM.

Response #5.a.(3): Disagree. Commenters appear to be suggesting that EPA is bound by state permitting decisions; however, as EPA stated in response #2.b above, state PSD permit actions are not binding on EPA and do not establish irrefutable precedence for EPA PSD permit actions. Further, by rule, BACT is a case-by-case determination. There may be case-specific reasons why certain permits contain different averaging times for their BACT limits. Although EPA has changed the filterable PM/PM10 limit from 30-day rolling average to daily average in the final permit, EPA has done so to conform with 40 CFR 60, subpart Da, not on the basis that EPA is bound by the averaging times in state permits.

As explained in response #5.a.(1), EPA's December 18, 2002 comment letter on the draft Roundup permit did not say the permit must include BACT limits corresponding to all averaging times of the PSD increments and NAAQS. Instead, the letter said only that there should either be short-term emission limits in the permit itself, or else the State should justify that worst-case hourly SO2 emission limits have been modeled for protection of short-term NAAQS and PSD increments. In the case of the WCFU permit, EPA has chosen to establish modeling limits to reflect the worst-case short-term emission rates assumed in dispersion modeling, for demonstration of short-term NAAQS and PSD increment protection.

EPA also disagrees with the comment that there should be a short-term emission limitation for VOC. Estimated potential emissions of VOC from the proposed project are 32 tons per year, below the PSD significance threshold. (draft Statement of Basis at 14.) A demonstration of NAAQS protection is not required where the estimated potential emissions of a pollutant (or precursor, in this case, VOC as a precursor of ozone) are below significance threshold. (draft Statement of Basis at 119) A BACT analysis is also not required. (draft Statement of Basis at 24)

EPA also disagrees with the comment that there should be a short-term emission limitation for CO. Since short-term emission limitations are generally used to protect PSD increments and NAAQS, and since there are no Class I or II increments for CO in PSD rules, the only applicable ambient standard that must be considered in response to comment #5.a.(3) is the CO NAAQS. While estimated potential emissions of CO from the proposed project are above the PSD significance threshold, the modeling results for ambient impacts from the proposed project were only 3.3% of the one-hour NAAQS for CO, and only 11.9% of the eight-hour NAAQS for CO. Because of these very low results in comparison to the NAAQS, and because modeling was based on "worst-case" startup emissions, EPA did not consider it necessary to include a lb/hr emission limit for CO in the permit. Since there is no Class I or II increment for CO in PSD rules, the only applicable ambient standard is the NAAQS.

Comment #5.a.(3) has not resulted in any change in the permit or Statement of Basis.

5.b – Meeting Enforceability Criteria:

Comment #5.b.(1): Commenters asserted that the permit must also specify appropriate compliance methods and recordkeeping requirements to show compliance with the short-term emission limits in comment 5.a. above. As discussed in the NSR Workshop Manual, "the construction permit should state how compliance with each limitation will be determined." (NSR Workshop Manual at H.6.). Commenters stated that the test methods must provide for continuous compliance where feasible. Commenters argued that when compliance with BACT emission limits is determined over a 30-day averaging period – even if monitored with continuous emission monitoring systems (CEMS), this does not ensure continuous compliance.

Response #5.b.(1): Disagree. Commenters have presented no basis for the implied claim that the permit fails to specify continuous compliance test methods where feasible. Continuous Emission Monitoring Systems (CEMSs) have been specified in the permit, at the CFB boiler stack, for every PSD pollutant where feasible. This includes CEMSs for particulate matter, SO_2, NO_x and CO. Commenters also have presented no basis for the claim that use of CEMS does not ensure continuous compliance with 30-day average limits. The draft permit contains detailed requirements for testing of the accuracy of the CEMS for each pollutant, as well as quality assurance requirements, recordkeeping requirements, and reporting requirements. This includes quarterly reporting on the performance of the CEMSs. (Draft permit at pages 21-27.)

Comment #5.b.(1) has not resulted in any change to the permit or Statement of Basis.

Comment #5.b.(2): Commenters also alleged that the draft permit for the Bonanza WCFU lacks proper recordkeeping for some of the conditions of the permit:

First, EPA must require Deseret to maintain records of all weekly Method 22 visible emissions (VE) evaluations of the unenclosed coal and limestone stockpiles required by Condition III.F.3. of the draft permit, in addition to maintaining records of all Method 9 opacity observations (per Condition III.I.8.c. of the draft permit).

Second, regarding the monitoring of coal quality and sulfur content, EPA must require that heat content and sulfur content be tested and recorded on a daily basis for all coal used (i.e., washed or “run-of-mine” coal used during “emergencies” or in whole or blended in part during other times). This is necessary for comparison to a percent SO_2 removal requirement, which commenters contend is necessary to ensure BACT is met over the wide variety of coal quality and sulfur content that will be used in the Bonanza WCFU.

Response #5.b.(2): Partially agree**.** Commenters appear to be suggesting that the permit fails to require the above-mentioned recordkeeping. EPA finds that commenters are correct on the first point (Method 22 VE evaluations), but not on the second point (heat content and sulfur content of coal).

Regarding the first point, EPA agrees with commenters that language should be added to permit condition III.I.8.c, to require that records be kept of the weekly Method 22 visible emission evaluations required by condition III.F.3. EPA acknowledges that without recordkeeping, the requirement to conduct weekly Method 22 evaluations would not be enforceable as a practical matter. EPA added this recordkeeping requirement to condition III.I.8.c. in the final permit.

Regarding the second point, EPA disagrees with commenters' apparent assertion that the draft permit fails to require daily records of heat content and sulfur content of coal, for all coal used. To the contrary, permit condition III.K.6 requires that records be kept of "all measurements of coal sulfur content and heat content required by this permit." Permit condition III.J.2 states that "The as-fired coal shall be tested each boiler operating day for sulfur content and heat content." The term "boiler operating day" is defined in permit condition III.D to mean "a 24-hour period between 12 midnight and the following midnight period during which any fuel is combusted at any time in the steam generating unit" (i.e., the CFB boiler). Therefore, contrary to commenters' apparent assertion, the permit does, in fact, require that heat content and sulfur content of the coal be tested and recorded on a daily basis for all coal used.

Comment #5.b.(2) has resulted in the addition of a requirement to permit condition III.I.8.c, that records be kept of the weekly Method 22 visible emission evaluations required by condition III.F.3.

6. EPA ADJUSTMENTS TO DESERET'S MODELING ANALYSIS

Comment #6:

One group of commenters argued that EPA must present its adjustments to Deseret's modeling analysis and provide opportunity to comment on the results. Commenters noted that in its draft Statement of Basis, EPA indicated that Deseret Power improperly determined the maximum short term SO_2 emission rates expected from the Bonanza WCFU that were used in the modeling analyses. (draft Statement of Basis at 135.) EPA re-calculated worst case short term SO_2 emission rates based on data provided by Deseret, and found "[w]hen the higher emissions values are used as input for dispersion models, it still appears to EPA that the NAAQS and PSD Class I and II increments would not be exceeded." However, commenters asserted, EPA did not provide the results of its dispersion modeling analysis with the higher worst case short term SO_2 emission limits to the public for review and comment.

Commenters further stated that EPA's revised 3-hour average SO_2 emission rate is almost six times greater than the 3-hour SO_2 emission rate modeled in Deseret's analyses, and the 24-hour average SO_2 emissions rate is close to 40% higher than what Deseret modeled. Commenters noted that Deseret accepted EPA's revised short term SO_2 emission rates as an amendment to its PSD permit application. Commenters argued that these increased emission rates should have been taken into account in estimating the significant impact area of the Bonanza WCFU (which, in turn, would be used to determine which sources should have been included in cumulative NAAQS and increment analyses), and also in determining whether preconstruction monitoring and/or cumulative PSD increment analyses should have been done.

Commenters further alleged that it is not clear whether EPA determined that, cumulatively with other sources in the region, the NAAQS and PSD Class I and II increments would not be exceeded with EPA's recalculated worst case SO_2 emission rates. Thus, commenters argued, EPA must present its revised modeling so the public can understand the true scope of short term average SO_2 impacts from the Bonanza WCFU and so that the public can ensure all CAA requirements will be complied with.

Response #6:

Partially agree. EPA does not agree that revised modeling must be done. No new modeling runs are necessary to account for EPA's adjustments to the modeling inputs for 3-hour and 24-hour SO_2. Emissions and concentrations are directly proportional in this type of model, so EPA simply scaled up the modeling results generated by Deseret's consultants to estimate local-scale impacts if worst case short term emission limits (i.e., the "Modeling Limits" in the permit) are ever reached.

As explained on pages 137-138 of the draft Statement of Basis ("EPA adjustments to permit applicant's modeling analysis"), EPA found that Deseret Power's assumed worst-case 3-hour average emission rate for SO_2, for modeling purposes, should have

been 872 lb/hr rather than 147 lb/hr, to account for a cold startup. EPA similarly found that Deseret Power's assumed worst-case 24-hour average emission rate for SO_2, for modeling purposes, should have been 202 lb/hr rather than 147 lb/hr. In evaluating the effect of these worst case emissions for modeling, EPA multiplied the WCFU's contribution to the modeling results shown on pages 130-134 of the draft Statement of Basis by a factor of [872/147 = 5.93] for 3 hour SO_2, and by a factor of [202/147 = 1.37] for 24 hour average SO_2. The corrected worst-case SO_2 emission rates for the WCFU (872 lb/hr on a 3-hour average and 202 lb/hr on a 24-hour average) are included as "Modeling Limits" in the draft WCFU permit. Modeling results still show compliance with the NAAQS and PSD increments for SO_2.

EPA does agree, however, that it should be made clear in the Statement of Basis how the corrected 3-hour and 24-hour WCFU emission rates are reflected in the modeling results. EPA has therefore scaled up the WCFU's contribution to the 3-hour and 24-hour SO_2 modeling results, in the following tables, on pages 161 through 164 of the Statement of Basis:

"NAAQS Compliance Demonstration for WCFU Project Sources"
"NAAQS Compliance Demonstration for Full Impact Area Sources"
"PSD Class II Increment Compliance for WCFU Sources (Near-field Analysis)"
"PSD Class II Increment Compliance for Full Impact Area Sources"

By "scale up," EPA means the modeling results in micrograms per cubic meter (ug/m^3) for the WCFU are multiplied by the factors mentioned above, which are 5.93 for 3-hour SO_2 and 1.37 for 24-hour SO_2, to reflect the worst-case short-term SO_2 emission scenario at the WCFU. Explanations have also been included in the Statement of Basis as to why these changes to the modeling results tables have been made.

EPA has also corrected the WCFU emission rates for 3-hour and 24-hour SO_2 in the Statement of Basis table titled, "ISC3 WCFU Stack Input Parameters Used for Modeling." EPA has also included the corrected WCFU emission rates in a PSD Class I increment compliance screening analysis, described in Response #9 below and added to the Statement of Basis.

EPA also agrees that its revision to Deseret's SO_2 emissions estimate for the WCFU should be taken into account in estimating the significant impact area of the WCFU. In Deseret's original analysis, the Class II significant impact area for SO_2 was a 16-kilometer radius from the proposed WCFU. Deseret added 50 kilometers to the impact area radius and looked for other increment affecting sources within 66 kilometers of the proposed WCFU. Other than Bonanza Unit 1, there were no other sources in the 66-kilometer radius impact area. The revised emission estimate for the WCFU would expand the impact area somewhat, but there are no additional large SO_2 sources near the edge of the 66-kilometer impact area. (This area is very remote.) At distances exceeding 66 kilometers, it would take a huge source to materially affect increment concentrations and there are none that large within at least 100 kilometers of the proposed WCFU. This additional explanation will be added to the final Statement-of-Basis.

In summary, Comment #6 has not resulted in any change to the permit; however, the changes described above have been made to the WCFU stack parameter table and to the modeling results tables in the Statement of Basis. Additional changes to the modeling results tables, to account for higher 3-hour and 24-hour SO_2 emission rates at Bonanza Unit 1 (140 g/sec and 106 g/sec, respectively), and to account for a 29% increase in SO_2 emissions at Unit 1 since 1991-93, are described in Responses #7 and #8.b. below, respectively.

7. CUMULATIVE NAAQS/INCREMENT ANALYSIS FOR SULFUR DIOXIDE

Comment #7:

One group of commenters asserted that Deseret's cumulative SO_2 NAAQS and Class II PSD increment analysis is flawed because the 2002 SO_2 emission rate modeled for Bonanza Unit 1 is much lower than the peak short term SO_2 emission rate for this unit in 2002. Specifically, commenters stated, Deseret assumed an SO_2 emission rate, purportedly based on 2002 actual emissions, of 56.30 grams per second (g/s). However, commenters stated, a review of the 2002 SO_2 emission data for Bonanza Unit 1 on EPA's Clean Air Markets Database indicates that the maximum three-hour average SO_2 emission rate was 126 g/s (1000 lb/hr) and the maximum 24-hour average SO_2 emission rate was 115.9 g/s (920 lb/hr).

Thus, commenters argued, Deseret Power underestimated Bonanza Unit 1's impacts on the short term average SO_2 NAAQS and increment. Commenters concluded that the NAAQS and increment analyses must be revised to model the highest 3-hour and 24-hour average emission rate of Bonanza Unit 1, as well as to model the EPA adjusted worst case 3-hour and 24-hour average SO_2 emission rates expected from the Bonanza WCFU. Commenters also asserted that the peak 3-hour and 24-hour SO_2 emission rates of Bonanza Unit 1 must be used in the cumulative Class I SO_2 increment modeling that is required. (See related comment #9 below.)

Response #7:

Partially agree. EPA does not agree that the modeling is flawed. Deseret Power conducted additional PSD increment analysis, in response to EPA comments that Bonanza Unit 1 SO_2 emission rates appeared to be too low for use in modeling PSD short term increments. (Ref: EPA letters to Deseret dated November 22 and 29, 2004, and Deseret's response letter to EPA dated March 23, 2005, all included in the Administrative Record for issuance of the WCFU permit.)

Specifically, Deseret Power re-modeled for PSD Class I SO_2 increment consumption at the nearest state-classified Class I area (Dinosaur National Monument in Colorado) using the maximum actual emission rates for Bonanza Unit 1 from the 2001-2002 period (140 g/sec for 3-hour increment and 106 g/sec for 24-hour increment). (Note: Dinosaur is not a mandatory Federal Class I area, but is classified as Class I by the State of Colorado.) The results are summarized in Deseret Power's March 23, 2005 letter to EPA. As explained in Response #9 below, EPA has conducted a separate screening analysis for impact on mandatory Federal Class I areas, which are somewhat more distant (Arches, Canyonlands and Capitol Reef National Parks).

The results of these analyses show that cumulative impacts of the proposed WCFU and existing Bonanza Unit 1 do not threaten the PSD Class I increment at Dinosaur and the impacts are expected to be even smaller at other more distant Class I areas. Deseret Power stated that no continuous emission monitoring system (CEMS) data

for startup/shutdown/ malfunction were excluded in determining the corrected maximum 3-hour and 24-hour emission rates from Bonanza Unit 1 used as inputs for the revised modeling. (Ref: E-mail dated November 13, 2006, from Ed Thatcher of Deseret Power to Mike Owens of EPA Region 8.)

EPA does agree, however, that the corrected 3-hour and 24-hour peak emission rates for Bonanza Unit 1 and the revised modeling analysis, as reported by Deseret Power to EPA on March 23, 2005, as well as revised modeling results to account for worst-case 3-hour and 24-hour SO_2 emission rates at the WCFU, should be reflected in the modeling results tables in the Statement of Basis. Revisions to those tables to account for the worst-case 3-hour and 24-hour emission rates at the WCFU are described in Response #6 above. Additional revisions, to account for the higher 3-hour and 24-hour emission rates at Unit 1, have been made to the following modeling results tables, on pages 162 and 164 of the Statement of Basis:

"NAAQS Compliance Demonstration for Full Impact Area Sources"
"PSD Class II Increment Compliance for Full Impact Area Sources"

In addition, the 3-hour and 24-hour SO_2 emission rates for Bonanza Unit 1 have been revised in the table titled, "Bonanza Unit 1 Stack Parameters Used for Modeling." Further, a reference to Deseret Power's March 23, 2005 Class I increment analysis for Dinosaur National Monument has been added to the Statement of Basis.

In summary, Comment #7 has not resulted in any change to the permit; however, the changes described above have been made to the Statement of Basis.

Additional changes to the modeling results tables in the Statement of Basis, to account for worst-case 3-hour and 24-hour SO_2 emission rates at the WCFU, and to account for a 29% increase in SO_2 emissions at Unit 1 since 1991-93, are described in Responses #6 and #8.b, respectively.

8. PRE-APPLICATION AMBIENT MONITORING FOR SULFUR DIOXIDE

Comment #8:

Comment #8.a: One group of commenters stated that it appears that Deseret should not have been exempted from one year of pre-construction ambient monitoring for SO_2. Commenters asserted that although the PSD permit application shows that the SO_2 impacts from the Bonanza WCFU would be less than the monitoring significance levels, this modeling was based on Deseret's flawed approach of estimating worst case short term emission rates.

Commenters noted that Deseret Power's worst case SO_2 emission rate modeled was 146.99 lb/hr. (draft Statement of Basis at 135.) EPA's recalculated worst case 24-hour average SO_2 emission rate was 201.9 lb/hr. Multiplying Deseret Power's original 24-hour maximum near field modeling result of 10.8 ug/m3 for SO_2 (as provided in the Statement of Basis at 128) by the ratio of the revised worst case short term emission rate to the originally modeled worst case SO_2 emission rate, results in a maximum 24-hour average SO_2 ambient concentration of 14.8 ug/m3. This exceeds the 24-hour SO_2 monitoring significance level of 13 ug/m3. Thus, commenters argue, it appears that Deseret should have conducted one year of pre-application ambient monitoring for SO_2. Consequently, commenters asserted, EPA must delay issuing the permit until this data is collected.

Response #8.a: Disagree. There is no reason to require one year of pre-construction ambient SO_2 monitoring, if representative ambient SO_2 concentration data are already available. Ambient SO_2 air quality monitoring data are available from the plant site for the period 1991-1993. These data are considered by EPA to be representative, since the data were collected on site, and there were no other major sources of SO_2 in the area then, and none have been added since that time. The data were collected in accordance with EPA's PSD monitoring guidelines

EPA's ambient monitoring guidelines for PSD list the following three criteria that must be met, for pre-construction monitoring data to be considered representative of pre-construction ambient air quality for PSD purposes

- Section 2.4.1 - Monitor location;

- Section 2.4.2 - Data Quality [the guideline says the data should be of similar quality as would be obtained if the applicant monitored according to the PSD requirements]; and

- Section 2.4.3 - Currentness of the data [the guideline says the data should be current, which generally means, for the pre-construction phase, the data must have been collected in the 3-year period preceding the permit application, provided the data are still representative of current conditions].

(Ref: Pages 6 through 9 of EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87- 007 (May 1987), available through website at: http://www.epa.gov/ttnamti1/files/ambient/criteria/reldocs/4-87-007.pdf)

The Environmental Appeals Board (EAB) has also recognized that the permitting authority may allow for representative data gathered from other time periods. (*See In re Encogen Cogeneration Facility*, 8 EAD 244, 255-257 (1999); *In re Hawaii Electric Light Co*., 8 EAD 66, 97 (1998); *In re Kawaihae Cogeneration Project*, 7 EAD 107, 128 (1997).)

The first criterion above was met because the 1991-93 ambient data were collected on-site (Ref: November 1, 2004 PSD permit application, volume titled "Dispersion Modeling, Deposition and Visibility Analyses," page 3-3, included in the Administrative Record for issuance of the WCFU permit.)

The second criterion above was met because all of the data were collected in compliance with the quality assurance provisions in EPA's above-mentioned ambient monitoring guidelines. (Ref: E-mail from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, dated November 9, 2006, included in the Administrative Record for issuance of the WCFU permit.)

The third criterion above was met because, although the data were not collected within a three-year period preceding the PSD permit application, the data are considered representative because there have been no substantive emission changes in the vicinity of the proposed project since the 1991-93 period. Emission changes at Bonanza Unit 1 since 1991-93 have been accounted for as described in the remainder of this response.

In summary, comment #8.a has not resulted in any change in the permit; however, an expanded explanation has been included in the Statement of Basis, on why Deseret Power is exempt from pre-construction ambient monitoring for SO_2.

Comment #8.b: As mentioned in comment #6 above, EPA re-calculated maximum short term SO_2 emission rates but, according to commenters, did not present the results of its revised modeling analyses. Commenters noted that, considering the emissions rate is all that would be changed in the revised modeling, one can simply adjust the results proportionately based on the EPA's revised emission rate as compared to Deseret's modeled SO_2 emission rate.

Response #8.b: Agree. EPA inadvertently failed to revise the modeling results tables in the draft Statement of Basis to account for EPA's re-calculation of maximum (worst case) short term SO_2 emission rates at the WCFU. The tables have been revised in the Statement of Basis.

When re-evaluating the modeling in response to comments, EPA found, however, that Deseret used ambient air quality data from the Bonanza site for 1991-1993 for determining ambient background concentrations, but failed to consider the effect of

potential growth in Bonanza Unit 1 emissions since that time. (Ref: November 13, 2006 e-mail from Deseret Power to EPA, included in the Administrative Record for issuance of the WCFU permit.)

To consider the effect of Unit 1 emission changes, EPA's AirData base was reviewed by Deseret Power and emissions, in tons per year for Uintah County, for SO_2, NO_x, CO, PM_{10}, and VOC were obtained for 1990 and 2001. These data are presented below. Based on Table 1, emissions of CO, NO_x, and VOC have decreased; SO_2 and PM_{10} emissions have increased by 27.3 and 7.6%, respectively.

Table 1. Criteria Pollutant Emissions for Uintah County for 1990 and 2001

Pollutant	1990 (tons)	2001 (tons)	Change (tons)
CO	33,530	28,597	- 4,933
NO_x	10,110	8,991	- 1,119
SO_2	1,029	1,416	+ 389
VOC	5,818	2,952	- 2,866
PM_{10}	8,958	9,690	+ 732

Ref: November 1, 2006 e-mail from Deseret Power to EPA.

As noted above, the background values used did not account for the relatively small increase in Bonanza Unit I SO_2 emissions since 1993. The background concentrations used to determine National Ambient Air Quality Standards (NAAQS) compliance in Deseret Power's PSD permit application are listed in Table 2.

Table 2. Background Concentration Values

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	3-hour	20
SO_2	24-hour	10
SO_2	Annual	5
NO_2	Annual	5
PM_{10}	24-hour	10
PM_{10}	Annual	28
CO	1-hour	1 ppm
CO	8-hour	1 ppm

SO_2 emissions from Bonanza Unit 1 from 1991 through 1993, and 1994 through 2005, were reviewed to determine the percent increase over the period. The average SO_2 emissions from Unit 1, in tons, from 1991 – 1993 was 774; the average SO_2 emissions from Unit 1 from 1994 – 2005 was 1000.7. This represents a 29% emission increase from 1991 to 2005. (Ref: November 1, 2006 e-mail from Deseret Power to EPA.)

If we assume a 29% increase in the measured ambient SO_2 data collected at the Bonanza Power Plant from 1991 – 1993 (to account for the 29% emissions increase) and scale up the background concentrations used for the NAAQS compliance demonstration

by 29%, the resultant three-hour, 24-hour, and annual SO_2 background concentrations would be 25.8 µg/m^3, 12.9 µg/m^3, and 6.5 µg/m^3, respectively. Adding to this the highest modeled maximum SO_2 concentrations, from both the proposed WCFU and Bonanza Unit 1, based on 1993 meteorological data, the predicted ambient concentrations for the 3-hour, 24-hour, and annual averaging periods are 27.3%, 7.6% and 9.6% of the NAAQS, respectively.

In summary, comment #8 has not resulted in any change to the permit; however, the following modeling results tables, on pages 161 and 163 of the Statement of Basis, have been changed, to reflect the revised results for background concentrations, accounting for a 29% increase in Bonanza Unit 1 SO_2 emissions since 1991-93:

"NAAQS Compliance Demonstration for WCFU Project Sources"
"NAAQS Compliance Demonstration for Full Impact Area Sources"

Additional changes to the modeling results tables, to account for account for worst-case 3-hour and 24-hour SO_2 emission rates at the WCFU, and to account for higher 3-hour and 24-hour emission rates at Bonanza Unit 1, are described in Responses #6 and #7 above, respectively.

9. CUMULATIVE PSD INCREMENT ANALYSIS FOR CLASS I AREAS (AND FOR COLORADO CLASS I AREAS)

Comment #9:

One group of commenters asserted that Deseret Power failed to provide any cumulative PSD increment analysis for any affected Class I area in its permit application for the Bonanza WCFU, and that neither Deseret Power's PSD permit application, nor EPA's draft Statement of Basis, explains why cumulative increment analyses were not completed for Class I areas. Commenters asserted that PSD permitting regulations indicate that no PSD permit can be issued unless the source demonstrates that it will not cause *or contribute to* a violation of any PSD increment. 40 CFR 52.21(k)(2). Commenters argued that since Deseret has not made that demonstration, EPA cannot issue the permit.

Commenters postulated that one possible reason Deseret did not perform any cumulative Class I PSD increment analyses might be because Deseret considers the impacts of the Bonanza WCFU to be less than significance levels. (Commenters cited the Class I area impact tables on pages 4-21 through 4-28 of the dispersion modeling portion of Deseret's November 2004 PSD permit application, which identify the Bonanza WCFU's impact at each Class I area in terms of "Percent of EPA Class I Significance Levels.") However, commenters stated, there are no Class I area significance levels authorized in any federal regulation. While EPA proposed use of such Class I significant impact levels in July of 1996, EPA never finalized promulgation of those significant impact levels. Thus, commenters concluded, until EPA adopts significant impact levels for Class I increments, *any* impact must warrant a cumulative analysis.

Moreover, commenters argued, even if use of proposed but never finalized significant impact levels were appropriate to exempt the Bonanza WCFU from a cumulative increment analysis in affected Class I areas, cumulative SO_2 increment analyses would be required because the SO_2 impacts of the Bonanza WCFU would be greater than the proposed Class I significant impact levels for SO_2 in several Class I areas as follows:

Commenters argued that Deseret Power's modeling showed that its impact on the Colorado portion of Dinosaur National Monument would be greater than the SO_2 3-hour and 24-hour average proposed significant impact levels and greater than the 24-hour average Class I proposed significant impact level in Colorado National Monument. (Commenters cited pages 4-23, 4-24 and 4-30 of the dispersion modeling portion of the PSD permit application.) Colorado's regulations mandate that Dinosaur National Monument and Colorado National Monument, although Class II areas, will be subject to the more stringent Class I increments for SO_2. (Colorado Regulation 3, Part B, Section VIII.B.1.b.). Thus, commenters concluded, Deseret Power should have been required to perform a cumulative increment analysis for Dinosaur National Monument and Colorado National Monument.

Further, commenters asserted, Deseret Power's analysis of the Bonanza WCFU's impacts on short term average SO_2 concentrations in Class I areas was flawed because, as noted by EPA, Deseret underestimated worst case short term SO_2 emission rates from the Bonanza WCFU. (draft Statement of Basis at 135.) Commenters noted that, as discussed in the above comment regarding the monitoring significance threshold, the predicted SO_2 impacts on the Class I areas can be proportionately adjusted based on the EPA's revised SO_2 emission rates as compared to Deseret's modeled SO_2 emission rate.

Commenters further noted that EPA re-calculated Bonanza's WCFU worst case 3-hour average SO_2 emission rate to be 872 lb/hr, which is almost six times as high as the 146.99 lb/hr SO_2 emission rate modeled by Deseret. Commenters concluded that proportionately adjusting the 3- hour average SO_2 impacts of the Bonanza WCFU using EPA's revised worst case 3-hour average emission rate shows that the Bonanza WCFU would have an impact greater than the 3-hour average proposed significant impact level for SO_2 for most of the Class I areas in the region.

Commenters created and submitted a table to EPA, showing the revised Class I area 3-hour average SO_2 impacts based on EPA's revised worst case emission rates for those Class I areas where the Bonanza WCFU would exceed the proposed Class I significant impact levels. Based on that table, commenters argued that even if it were appropriate to exempt a facility from a cumulative Class I increment analysis based on its impacts being less than the proposed significant impact levels, the Bonanza WCFU would not be exempt from performing cumulative analyses of impacts on the 3-hour average SO_2 increment at Arches National Park, Canyonlands National Park, Capitol Reef National Park, Colorado National Monument, the Colorado portion of Dinosaur National Monument, the Flat Tops Wilderness area, and the Mt. Zirkel Wilderness Area.

Thus, commenters argued, Deseret Power must be required to conduct cumulative Class I increment analyses for the nearby Class I areas. EPA must not issue a PSD permit for the Bonanza WCFU without ensuring that the facility will not cause *or contribute* to a violation of any PSD increment.

Further, commenters argued, the cumulative Class I increment analyses must include the PSD increment consuming emissions of all other sources that could be affecting air quality in those Class I areas. This would include all large sources of air pollution within 200 kilometers of each Class I area, such as nearby coal-fired power plants (e.g., the Bonanza Unit 1, Hunter, Huntington, and Intermountain power plants in Utah, and the Craig, Hayden and Nucla power plants in Colorado).

In addition, commenters argued, Deseret Power must be required to model those facilities that have submitted complete PSD permit applications, and/or that have received air quality permits, but that have not yet constructed. This would include NEVCO's Sevier Power plant, Unit 3 of the Intermountain Power Plant, and Unit 4 of the Hunter Power plant, all to be located in Utah. Commenters further argued that Deseret Power must also include the existing and proposed oil and gas development occurring near the Class I areas that Bonanza will affect. Commenters concluded that until

complete and thorough Class I increment modeling analyses are completed, EPA cannot issue the permit because EPA will not know whether the facility will cause or contribute to a Class I increment violation.

Although commenters did not say their comment pertains only to SO_2, EPA interprets this to be the case, since the only pollutant mentioned in the comment was SO_2. Therefore, EPA's response below pertains only to SO_2.

Response #9:

Disagree. Given the modeling results from Deseret Power's PSD permit application of November 1, 2004 that indicate very small or no impacts on any Class I areas, EPA concluded that a cumulative PSD increment analysis for nearby Class I areas would not be necessary or required for the WCFU project. Further, an e-mail from the National Park Service to EPA on June 16, 2005, regarding Deseret's November 1, 2004 PSD permit application for the WCFU project, stated that "the modeling analyses for Class I and II PSD increments and impacts to Air Quality Related Values has been performed correctly and all issues regarding impacts to the NPS Class I and Class II units have been addressed."

The commenters' suggested use of worst case short term SO_2 emission rates ("modeling limits" in the permit), in determining impacts to Air Quality Related Values (AQRVs) or PSD increments, greater than 50 kilometers from the source, is not an approach EPA would require, since the worst case emission rate is not intended to represent a routine or frequent operating condition. The low frequency of occurrence of the WCFU facility operating at the worst case emission rate (reflecting a cold startup), combining with simultaneous meteorology to transport emissions a considerable distance to the nearest Class I area, makes the likelihood of impacts on the nearest Class I areas extremely unlikely.

Nevertheless, to be responsive to commenters, EPA conducted a screening analysis for cumulative impact on nearby mandatory Federal Class I areas (except Dinosaur National Monument, which is not mandatory Federal Class I and is addressed separately in response #7 above), using worst-case emission rates cited by public commenters. This was done by scaling Deseret Power's PSD Class I modeling analysis to the level of the worst case short term emission rates (as noted in response #6 above), even though this is not an approach EPA would require (as explained above).

Specifically, the 3-hour PSD increment concentrations were multiplied by 5.93 and the 24-hour PSD increment concentrations by 1.37. The adjusted modeled concentrations from the WCFU were then added to the cumulative PSD increment concentrations calculated by Intermountain Power Agency (IPA) for their Unit 3 PSD permit application in May of 2003. The modeling analysis in the IPA Unit 3 application has been reviewed and approved by the Utah Division of Air Quality. The State of Utah has a SIP-approved PSD permitting program and implements the PSD program in Utah.

That analysis showed that the PSD Class1 increment is not threatened in these areas. (See Table 3 below.)

Table 3
Cumulative PSD Increments Consumption for Selected Utah Class 1 Areas Based on Combined Modeled Impacts from Deseret WCFU and Reported PSD Increment Modeling Results from Intermountain Power Project, Unit 3

Location	3-hour SO2	24-Hour SO2	Annual SO2	24-Hour PM10	Annual PM10
Arches NP	3.8	0.8	0.1	0.2	.02
Canyonlands NP	9.6	2.2	0.1	0.2	.02
Capitol Reef NP	4.0	0.9	0.1	0.2	0.2
PSD Class 1 Increment	25	5	2	8	4

Ref: Addendum to Final Permit Application ("Notice-Of-Intent"), Intermountain Power Project, Proposed Unit 3, June 16, 2003.

In summary, Comment #9 has not resulted in any change to the permit; however, the Class I increment screening analysis described above has been added to the Statement of Basis. A separate analysis by Deseret Power, for impact on PSD Class I SO_2 increment at Dinosaur National Monument (a Colorado Class I area, not mandatory Federal Class I) is described in Response #7 above.

10. PSD INCREMENT CONCERNS AT CAPITOL REEF NATIONAL PARK

Comment #10:

One group of commenters asserted that EPA must not issue the PSD permit for the Bonanza WCFU in light of the PSD SO_2 increment violations that commenters asserted are occurring at Capitol Reef National Park. Commenters cited a March 25, 2004 letter from the National Park Service to the Utah Division of Air Quality, submitted during the permit review and proceedings for the proposed Unit 3 of the Intermountain Power Plant located in Delta, Utah. Commenters asserted that the letter expressed the concern that there are increment violations in Capitol Reef National Park.

On the basis of the NPS letter, commenters asserted that the Bonanza WCFU will contribute to existing SO_2 increment violations at Capitol Reef National Park, at a level greater than the proposed Class I significance level for 3-hour SO_2, and that EPA should not issue the PSD permit for the Bonanza WCFU until the increment violations are addressed.

Response #10:

Disagree. Neither EPA nor the State of Utah, the two agencies with authority to do so under the Federal Clean Air Act, has determined there is an increment violation at Capitol Reef National Park. The State of Utah has an EPA-approved PSD permitting program. In issuing the PSD permit for construction of Unit 3 at Intermountain Power Plant, the State of Utah concluded that the PSD increments are not threatened. In addition, in response to comment #9 above, EPA added the impact of Deseret Power's WCFU to the Intermountain Power Unit 3 PSD cumulative increment analysis results for Capitol Reef National Park and found no PSD increment violations.

Moreover, any concern for the potential of increment violations at Capitol Reef National Park should be further minimized by the fact that Pacificorp recently applied for permits from the State of Utah for installation of additional controls at the Hunter and Huntington plants in Delta, Utah, both of which are closer to Capitol Reef National Park than Deseret Power's proposed WCFU at Bonanza, Utah. These additional controls are projected by Pacificorp and the State of Utah to yield a total of 21,560 tons per year of SO_2 emission reductions.

The permit ("Approval Order" in Utah's terminology) for additional emission controls at the Huntington plant was issued by the State of Utah on April 6, 2005, and cites expected emission reductions of 17,479 tons per year of SO_2, 2,781 tons per year of NO_x, and 1.432 tons per year of PM_{10}. (Ref: Approval Order dated April 6, 2005, included in the Administrative Record for issuance of the WCFU permit.)

The permit for additional emission controls at the Hunter plant was proposed by the State of Utah on March 2, 2007 ("Intent-To-Approve" in Utah's terminology), but is not yet finalized, as of early August 2007. The ITA cites expected emission reductions of

4,081 tons per year of SO_2, 8,754 tons per year of NO_x, and 1,441 tons per year of PM_{10}. (Ref: Intent-To-Approve dated March 2, 2007, included in the Administrative Record for issuance of the WCFU permit.)

These additional controls at the Huntington and Hunter plants are expected by EPA to further reduce the level of PSD increment consumption from those shown in Table 3 above. The potential controlled SO_2 emissions from the WCFU project are only 348 tons per year based on the proposed upper-tier emission allowable of 0.055 lb/MMBtu, or only 253 tons per year based on the proposed lower-tier emission allowable of 0.040 lb/MMBtu.

In summary Comment #10 has not resulted in any change to the permit or Statement of Basis.

11. VISIBILITY MODELING

Comment #11:

One group of commenters asserted that Deseret Power's visibility modeling analysis of the Bonanza WCFU is flawed because Deseret Power failed to model maximum 24-hour average emissions of SO_2 and because Deseret Power failed to properly document why it was necessary or appropriate to rollback the relative humidity in the regional haze modeling to 95%. Consequently, commenters argued, the modeling likely underestimated the impacts of the Bonanza WCFU on visibility in nearby Class I areas.

Comment #11.a: Commenters noted that, as discussed above, EPA adjusted the worst case 24-hour SO_2 emission rate based on data from Deseret Power because Deseret Power's estimate of worst case SO_2 emissions did not properly include emissions from start-ups. (draft Statement of Basis at 135.) With EPA's adjustment, the worst case 24-hour average SO_2 emission rate is 37% higher than the emission rate that was modeled in Deseret's visibility analysis. Thus, commenters argued, Deseret's visibility analysis underestimated visibility impacts in all affected Class I areas. Commenters asserted that Deseret must be required to re-model visibility impacts using the adjusted worst case 24-hour average SO_2 emission rate of 201.9 lb/hr and such modeling must be provided to the Federal Land Managers for review.

Response #11.a: Disagree. As noted in response #9 above, the National Park Service stated on June 16, 2005, in regard to the PSD permit application for the WCFU, that "the modeling analyses for Class I and II PSD increments and impacts to Air Quality Related Values has been performed correctly and all issues regarding impacts to the NPS Class I and Class II units have been addressed."

Also, it appears that commenters may have used a scaling technique to determine that the Bonanza WCFU would have an adverse visibility impact at some nearby Class 1 areas. Scaling the Calpuff model is not appropriate when reviewing visibility and deposition results. Calpuff converts a portion of the SO_2 emissions to sulfate particulate and a portion of the NO_X emissions to nitrate particulate as the plume is transported. Thus, visibility and deposition values are not linear to the emission rate. Comment #11.a has not resulted in any change to the permit or Statement of Basis.

Comment #11.b: Commenters also argued that Deseret estimated visibility impacts using both a maximum relative humidity of 98%, consistent with the Federal Land Managers' guidance, and rolling back relative humidity to 95%. (Commenters cited page 4-49 of the modeling portion of Deseret Power's PSD permit application.) However, commenters argued, the National Park Service has indicated that any analysis rolling back relative humidity to 95% would have to be "well documented as to why it is appropriate to. . .roll back relative humidity to 95% . . ." (Commenters cited an August 6, 2004 e-mail from John Notar, National Park Service, to Ed Thatcher of Deseret Power and Kevin Golden of EPA Region 8.) Commenters asserted that Deseret Power did not

provide any such documentation, therefore the results of its visibility analysis capping relative humidity at 95% cannot be relied upon.

Response #11.b: Disagree. With regard to the maximum relative humidity assumption, the Federal Land Managers (FLMs) have reviewed the draft permit package for this project and had no comment. It is EPA's understanding that in recent permit applications, the FLMs have broadly accepted the use of the 95 percent humidity threshold. The Draft Calpuff Reviewer's Guide, dated September 2005, prepared for the USDA Forest Service and the National Park Service (and included in the Administrative Record for issuance of the WCFU permit), indicates the general consensus among FLMs is that use of a maximum relative humidity value of 95% is appropriate for visibility modeling. (Ref: Page 6-1 of the Guide: "The CALPOST default value for RHMAX is 98, but the general consensus among FLMs is that RHMAX = 95 is appropriate.") Comment #11.b has not resulted in any change to the permit or Statement of Basis.

Comment #11.c: Commenters further argued that, based on the visibility modeling done by Deseret that is consistent with current guidance of the Federal Land Managers (i.e., capping relative humidity at 98%), the Bonanza WCFU will have an adverse impact on visibility (greater than a 5% change) at Arches and Capitol Reef National Parks. (Commenters cited page 4-51 of the modeling portion of Deseret's PSD permit application.) This analysis, commenters stated, must be redone with the EPA's worst case 24-hour average SO_2 emission rate and the results transmitted to the appropriate Federal Land Managers.

Response #11.c: Disagree. EPA does not agree that 98% relative humidity should have been used to model visibility impacts. See response #11.b above. Comment #11.c has not resulted in any change to the permit or Statement of Basis.

Comment #11.d: Commenters also asserted that, because the impacts on visibility will be greater using the higher SO_2 worst case 24-hour average emission rate, it appears the Bonanza WCFU will have an adverse visibility impact at some nearby Class I areas. Commenters concluded that EPA Region 8 must ensure that, in issuing a permit for the Bonanza WCFU, its actions are consistent with the intent of the PSD requirements of the Clean Air Act – specifically, whether its actions will preserve, protect, and enhance the air quality in nearby national parks and wilderness areas (i.e., pursuant to §160(1) of the Clean Air Act), and whether its actions will ensure that emissions from the Bonanza WCFU will not interfere with portions of State Implementation Plans aimed at preventing significant deterioration of air quality including preventing future visibility impairment (i.e., pursuant to §160(4) and 169(a)(1) of the Clean Air Act).

Response #11.d: Disagree. As explained in responses #11.a, 11.b and 11.c above, EPA's analysis and determinations have followed applicable rules and guidance, and the FLMs have no issue with the analysis and determinations. Comment #11.d has not resulted in any change to the permit or Statement of Basis.

In summary, Comments #11.a, b c and d have not resulted in any change to the permit or Statement of Basis.

12. MERCURY SIGNIFICANCE THRESHOLD

Comment #12:

One commenter asserted that an estimate of potential-to-emit for mercury should have been presented in the draft permit, and that a determination of whether the expected mercury emissions from the proposed WCFU will exceed PSD significance threshold should have been presented in the Statement of Basis. The commenter asserted the significance threshold of 0.1 tons per year (tpy) appears in the Federal PSD rules at 40 CFR 52.21(b)(23)(i). The commenter also remarked that coal-fired electric generating units are known to represent one of the largest sectors for mercury emissions, and that the issue of mercury significance should be explicitly discussed.

Response #12:

Disagree, for two reasons. First, the commenter's assertion is incorrect. The current Federal PSD rules at 40 CFR 52.21(b)(23)(i) have no significance threshold for mercury. On December 31, 2002, EPA revised the PSD rules to remove the significance threshold for mercury from §52.21(b)(23)(i). (Ref: 67 Fed. Reg. 80186, 80239-80240 (December 31, 2002)) Second, as discussed in detail in the final preamble to the December 31, 2002 rulemaking, EPA took final action to promulgate the proposed revisions and indicated that the "1990 Amendments to the CAA at section 112(b)(6) exempted HAP listed under section 112(b)(1) from the PSD requirements in part C." *Id*. EPA went on to indicate that the HAPs listed in section 112(b)(1) of the Clean Air Act, including mercury, are excluded from the PSD provisions of part C.

Comment #12 has not resulted in any change to the permit or Statement of Basis.

13. COMPLIANCE WITH NEW SOURCE PERFORMANCE STANDARD FOR MERCURY

Comment #13:

One commenter asserted that section III.I of the proposed permit for the WCFU should contain a provision to demonstrate compliance with 40 CFR 60.45Da, Standard for mercury. The commenter also asserted that the Statement of Basis should contain a discussion of the rank(s) of coal the CFB will burn and which standard within §60.45Da is applicable.

Response #13:

Disagree. Federal PSD rules at 40 CFR 52.21 do not require PSD permits to include emission standards from 40 CFR part 60, for mercury or any other pollutant. Also, the commenter's assertion that the draft Statement of Basis fails to cite the applicable mercury standard and coal category is incorrect. The applicable mercury standard from 40 CFR 60.45Da(a)(4) was shown in a table on page 115 of the draft Statement of Basis. The table may be found on page 143 of the final Statement of Basis, and is titled "Emission Limits in Amended NSPS Subpart Da as of July 1, 2007, Applicable to Units Commencing Construction after February 28, 2005."

Comment #13 has not resulted in any change to the permit or Statement of Basis.

14. COMPLIANCE DEMONSTRATIONS FOR OPACITY AT MATERIALS HANDLING VENT FILTERS AND BAGHOUSES

Comment #14:

One commenter noted that draft permit condition III.I.6, "Compliance demonstrations for opacity" at the materials handling vent filters and baghouses, states that "If no visible emissions are observed in three consecutive monthly observations, frequency of observations at that baghouse or vent filter may be reduced to quarterly." The commenter asked EPA, "If the opacity observations have been reduced to quarterly, and an observation finds visible emissions, do the observations remain at quarterly, or return to monthly?"

Response #14:

Agree. The commenter appears to be suggesting that the permit should clarify whether the required frequency of visible emission observations reverts back to monthly from quarterly, in the event that visible emissions are observed. EPA agrees that the permit should be clear on this. Since conditions at a materials handling vent filter or bagbouse can vary over time, it is EPA's intent that frequency of observations revert back to the original frequency (i.e., monthly), if visible emissions are observed. Relaxation of observation frequency should serve as an ongoing incentive (not just a one-time-only incentive) to maintain good particulate control.

Comment #14 has resulted in the above-mentioned clarification in the final permit and Statement of Basis.

15. REFERENCES IN STATEMENT-OF-BASIS TO INTERMOUNTAIN POWER UNIT 3 PROJECT

Comment #15:

One commenter noted that the draft Statement of Basis, at page 51, references the Utah Division of Air Quality's "Modified Source Plan Review" for the Intermountain Power Unit 3 (IPP3) project. The commenter stated that the IPP3 permit action is under challenge by the Sierra Club and Grand Canyon Trust, therefore "possibly it is unwise to add into the record an analysis that may be overturned."

Response #15:

Disagree, for two reasons. First, since the IPP3 permit has not been overturned, EPA sees no reason to delete references to Utah's "Modified Source Plan Review" for that permit action. Second, EPA does not believe its reference to Utah's "Modified Source Plan Review" is connected to the "challenge" cited by the commenter. EPA's draft Statement of Basis referenced the "Modified Source Plan Review" only in regard to a statement by the Utah Division of Air Quality (DAQ) that no more than 80 percent removal efficiency might be expected for sulfuric acid, for a wet electrostatic precipitator (ESP) at a pulverized coal-fired boiler, under optimum conditions. EPA's draft Statement of Basis also cited other sources of information on sulfuric acid removal efficiency where a wet ESP is used, and concluded that an estimate of 86% should be used for EPA's analysis, not 80%. EPA presented the Utah DAQ's estimate only to show that estimates vary.

While EPA is not certain what the commenter means by a "challenge" to the IPP3 permit, EPA presumes that the "challenge" arose from a comment letter dated May 20, 2004, on the draft PSD permit for the Intermountain Power Unit 3 project. The letter was submitted to the Utah DAQ by the Sierra Club, Grand Canyon Trust, and several other environmental organizations. Page 31 of the comment letter notes the Utah DAQ's estimate of 80% removal efficiency for sulfuric acid. The comment letter does not question that estimate. Rather, the comment letter states that Utah DAQ and Intermountain Power did not properly follow EPA's cost effectiveness formulas, and thus these calculations cannot be relied on to eliminate a wet ESP from review. (A copy of the May 20, 2004 comment letter is included in the Administrative Record for issuance of the WCFU permit.)

In summary, EPA does not consider the challenge to the Intermountain Power Unit 3 permit to be a reason to remove from its own Statement of Basis the reference to the Utah DAQ's "Modified Source Plan Review." Comment #15 has not resulted in any change to the permit or Statement of Basis.

16. TYPOGRAPHICAL ERROR IN PERMIT

Comment #16: One commenter stated that permit condition III.H.1.a has a typographical error. It should cross-reference permit condition III.E.3 rather than III.E.4.

Response #16: Agree. The correction will be made in the final permit.

C. CHANGES TO THE PERMIT AND STATEMENT OF BASIS IN RESPONSE TO PUBLIC COMMENT

Permit:

From response #4.b.(1): Revised the "cutpoint" in permit conditions III.D.1.b.(ii)*(a)* and *(b)* from 1.9 lb/MMBtu to 2.2 lb/MMBtu.

From response #5.a.(1):

- Changed the averaging time of the emission limits at the CFB boiler stack in permit condition III.D.1.a, for total particulate matter and for filterable particulate matter, from 30-day rolling average to 24-hour block average.

- Changed permit condition III.I.4.d, to delete "total particulate matter including condensibles" and "total filterable particulate matter" from the first sentence on 30-day rolling averages.

- Added a paragraph to permit condition III.I.4.d, to say that emissions of "total particulate matter" and "total filterable particulate matter" shall be calculated on a 24-hour block average basis (midnight to midnight).

- Changed permit condition III.J.1.f, to add the phrase "and 24-hour block average emission rates" to the second sentence.

- Changed permit condition III.L.2.a, to add "24-hour block averages" to the title line. Made corresponding change in the Table of Contents. Changed the language in the condition to say that for SO_2, NO_x and CO, reports of 30-day rolling average emissions are required, but that for total particulate and total filterable particulate matter, reports of 24-hour block average emissions are required.

- Changed permit condition III.L.2.a.(iii), to say that the language about 30 successive boiler operating days pertains only to SO_2, NO_x and CO, not to total particulate matter or total filterable particulate matter.

- Added a new permit condition III.L.2.a.(iv), to say that for total particulate matter and for total filterable particulate matter, the average emission rate in lb/MMBtu for each boiler operating day shall be reported. ("Boiler operating day" is defined at the beginning of permit condition III.D and means a period from midnight to midnight, which corresponds to a 24-hour block average.)

- Moved the language about reporting for periods of non-compliance, startups, shutdowns and malfunctions from permit condition III.L.2.a.(iii) to a new permit condition III.L.2.a.(v).

- Re-numbered the remaining provisions of permit condition III.L.2.a., from III.L.2.a.(iv) through.(viii), to III.L.2.a.(vi) through (x).

From response #5.a.(1): Changed title of permit section III.D from "PSD BACT Emission Limits" to "PSD BACT and Other Emission Limits." Added a footnote to permit condition III.D.3 regarding opacity limit.

From response #5.b.(2): Added requirement in permit condition III.I.8.c to keep records of the weekly Method 22 observations required by condition III.F.3.

From response #14: Added a clarifying statement to permit condition III.I.6 that if any visible emissions are observed in a quarterly observation at a baghouse or vent filter, the frequency of observation at that baghouse or vent filter shall return to monthly.

From response #16: Corrected typographical error in permit condition III.H.1.a, to cross-reference permit condition III.E.3 rather than III.E.4.

Other minor administrative changes made to the draft permit:

In permit condition III.H.3, at the end of the condition, added the phrase "and any changes required by EPA."

In permit condition III.I.2.a, corrected the references to NSPS Subpart Da, regarding exemptions from emission standards. The meaning of the permit condition was not changed.

Added a permit condition III.L.9, to require written notification to EPA of the date that construction commences on the WCFU project, within 15 days after commencement. Re-numbered existing condition III.L.9 to III.L.10.

Updated the EPA street address in permit condition III.L.9, now condition III.L.10.

Reworded permit condition IV.B, "Permit Effective Date," to say "This PSD Permit becomes effective 30 days after the service of notice of the final permit decision, unless review of the permit decision is requested pursuant to 40 CFR 124.19."

Statement of Basis:

From response #3:

Added a new SOB subsection VI.E ("Supercritical Boiler Technology for BACT"), to explain why supercritical CFB boiler technology was eliminated as a BACT control option. Remaining subsections of section VI have been re-numbered accordingly.

From response #4.a:

In SOB subsection VI.D.1 ("Alternative from Deserado mine" as a BACT option), adjusted the estimate of potential emission reductions of condensible PM that might be achieved by switching from waste coal to ROM coal at the Deserado mine. Adjusted the $/ton annualized cost of BACT accordingly. EPA's conclusion that cost of ROM coal is excessive for BACT remains unchanged.

In SOB section VI.D.2 ("Alternative coal from other mines" as a BACT option), expanded the explanation of why alternative coal from other mines has been eliminated as a BACT option. The explanation now includes $/ton calculations on cost of this BACT option, along with a comparison of this cost versus the cost that other similar sources have to bear for BACT. EPA's conclusion that cost of alternative coal from other mines is excessive for BACT remains unchanged.

From response #4.b.(1):

In SOB subsection VI.K.5 (Step 5 of the SO_2 BACT analysis), added an explanation titled "Revision of proposed cutpoint" on why EPA has revised the "cutpoint" from 1.9 to 2.2 lb/MMBtu in permit condition III.D.1.b.(ii). Also added AES-Puerto Rico and Nevco Energy to the table titled, "Coal Scenarios and Sulfur Dioxide Control Efficiency, Comparisons for CFB Projects: EPA Compilation."

Also corrected the calculations in subsection VI.K.5, for "worst-case" coal at AES-Puerto Rico, from 1.7 lb/MMBtu and 98.7% control efficiency to 1.3 lb/MMBtu and 98.3% control efficiency.

The numerical value of the SO_2 BACT emission limit itself remains unchanged.

From response #4.c.(1):

In SOB subsection VI.G.1 (Step 1 of the NO_x BACT analysis), added a discussion of potential NO_x control options from the Nov. 1999 EPA Technical Bulletin that were not already addressed in the draft SOB, along with an explanation of why all but two of the options were eliminated at Step 1 of the top-down BACT analysis.

In SOB subsection VI.G.2, added an explanation of why the remaining two options from the Nov. 1999 Bulletin were eliminated at Step 2. EPA's conclusion that SCR and SNCR are the only technically feasible NO_x control options remains unchanged.

From responses #4.c.(4) and (5):

In SOB subsection VI.G.3 (Step 3 of the NO_x BACT analysis), added a statement that the potential NO_x control effectiveness of SCR has been revised from 0.04 to 0.015 lb/MMBtu at Step 3 of the BACT analysis, to reflect the possibility that a rate as low as 0.015 lb/MMBtu could be achieved, rather than 0.04 lb/MMBtu. Explained that this revision is based on information from Babcock & Wilcox, cited in public comments on the draft SOB. The cost effectiveness ranking at Step 3 remains unchanged.

In SOB subsection VI.G.4 (Step 4 of the NO_x BACT analysis), revised the reheat cost analysis for SCR in VI.G.4.a, to account for the aforementioned change in potential control effectiveness. EPA's conclusion that SCR should be eliminated at Step 4 remains unchanged.

From response #4.c.(8):

In SOB subsection VI.G.5 (Step 5 of the NO_x BACT analysis), added the Kentucky Mountain Power Project to the table titled "Summary of Recent CFB Projects Permitted or Proposed: NO_x Emission Rates Using SNCR." Also added an explanation titled "Note 1" on why EPA has discounted to some degree the significance of KMPP's initial NO_x emission limit of 0.07 lb/MMBtu. EPA's conclusion on what emission limit to impose as NO_x BACT remains unchanged.

From response #4.e.(2):

In SOB subsecton VI.H.7 ("Proposed compliance monitoring approach" for PM/PM_{10} filterable emissions), expanded the explanation of why no opacity limit or opacity monitoring for the CFB boiler exhaust stack are considered necessary in the permit. EPA's conclusion that no opacity limit or opacity monitoring is necessary remains unchanged.

From response #5.a.(1):

In SOB subsection VI.H.5 (Step 5 of the BACT analysis for PM/PM_{10} filterable emissions), added an explanation of why EPA has revised the averaging time of the PM/PM_{10} filterable emission limit in permit condition III.D.1.a from 30-day rolling to daily.

In SOB subsection VI.I.5 (Step 5 of the BACT analysis for PM/PM_{10} condensible emissions), revised the averaging time of the total PM/PM_{10} emission limit (including condensibles) from 30-day rolling to daily, to be consistent with the revised averaging time of the emission limit for the filterable portion.

From response #6:

In SOB subsection VIII.C.7, corrected the WCFU emission rates for 3-hour and 24-hour SO_2 in the table retitled, "ISC3 WCFU Stack Input Parameters Used for Modeling, As Corrected by EPA for 3-Hour and 24-Hour SO_2." The 3-hour rate was scaled up by a factor of 5.93 and the 24-hour rate was scaled up by a factor of 1.37.

In SOB subsection VIII.E.1.a, scaled up the WCFU's 3-hour and 24-hour SO_2 modeling results, in the table retitled "NAAQS Compliance Demonstration for WCFU Project Sources (Results as Corrected by EPA for SO_2)." Added an explanation why the results were scaled up.

In SOB subsection VIII.E.1.b, scaled up the WCFU's contribution to the 3-hour and 24-hour SO_2 full impact modeling results, in the table retitled "NAAQS Compliance Demonstration for Full Impact Area Sources (Results as Corrected by EPA for SO_2)." Added an explanation why the results were scaled up.

In SOB subsection VIII.E.2.a, scaled up the WCFU's 3-hour and 24-hour SO_2 modeling results, in the table retitled "PSD Class II Increment Compliance for WCFU Sources (Near-field Analysis) (Results as Corrected by EPA for SO_2)." Added an explanation why the results were scaled up.

In SOB subsection VIII.E.2.b, scaled up the WCFU's contribution to the 3-hour and 24-hour SO_2 full impact modeling results, in the table retitled "PSD Class II Increment Compliance for Full Impact Area Sources (Results as Corrected by EPA for SO_2)." Added an explanation why the results were scaled up.

(By "scale up" for the WCFU, EPA means the modeling results in micrograms per cubic meter (ug/m^3) attributable to the WCFU are multiplied by 5.93 for 3-hour SO_2 and 1.37 for 24-hour SO_2, to reflect the worst-case short-term SO_2 emission scenario at the WCFU.)

In SOB subsection VIII.E.3, added a reference to Deseret Power's March 23, 2005 Class I increment analysis for Dinosaur National Monument, which revised the modeling results to account for the higher short-term SO_2 emission rates at Bonanza Unit 1, as well as to account for the worst-case short-term SO_2 emission scenario at the WCFU.

In SOB subsection VIII.E.3, included the corrected WCFU emission rates for 3-hour and 24-hour SO_2 in a PSD Class I increment compliance screening analysis (described by EPA in response #9).

EPA's conclusion that the NAAQS and the PSD Class II increments will not be exceeded remains unchanged.

From response #7:

In SOB subsection VIII.C.7, corrected the Bonanza Unit 1 emission rates for 3-hour and 24-hour SO_2 in the table retitled, "Bonanza Unit 1 Stack Parameters Used for Modeling, As Corrected by EPA for 3-Hour and 24-Hour SO_2." The 3-hour rate was changed from 56.3 g/sec to 140 g/sec. The 24-hour rate was changed from 56.3 g/sec to 106 g/sec. These higher rates reflect maximum actual emission rates from the 2001-2002 period.

In SOB subsection VIII.E.1.b, scaled up Unit 1's contribution to the 3-hour and 24-hour SO_2 full impact modeling results, in the table retitled "NAAQS Compliance Demonstration for Full Impact Area Sources (Results as Corrected by EPA for SO_2)." Added an explanation why the results were scaled up.

In SOB subsection VIII.E.2.b, scaled up Unit 1's contribution to the 3-hour and 24-hour SO_2 full impact modeling results, in the table retitled "PSD Class II Increment Compliance for Full Impact Area Sources (Results as Corrected by EPA for SO_2)." Added an explanation why the results were scaled up.

(By "scale up" for Unit 1, EPA means the modeling results in micrograms per cubic meter (ug/m^3) attributable to Unit 1 are multiplied by a factor of 140/56.3 for 3-hour SO_2 and by a factor of 106/56.3 for 24-hour SO_2, to reflect higher short-term SO_2 emission rates at Unit 1.)

In SOB subsection VIII.E.3, added a reference to Deseret Power's March 23, 2005 Class I increment analysis for Dinosaur National Monument (which revised the modeling results to account for the higher short-term SO_2 emission rates at Bonanza Unit 1, as well as to account for the worst-case short-term SO_2 emission scenario at the WCFU).

EPA's conclusion that the NAAQS and the PSD Class II increments will not be exceeded remains unchanged.

From response #8.a:

In SOB subsection VIII.D, revised the 3-hour and 24-hour SO_2 "modeled maximums" in the table retitled "Near-Field WCFU Modeling Results and Comparison to Monitoring Exemption Levels (Modeled Maximums As Corrected by EPA for 3-Hour and 24-Hour SO2)," to reflect a 29% increase in Bonanza Unit 1's SO_2 emissions since the 1991-1993 period.

Also expanded the explanation of why Deseret Power should still qualify for the exemption from pre-construction ambient monitoring, even though the corrected 24-hour SO_2 modeled maximum is above the exemption threshold in 40 CFR 52.21(i)(5)(i). EPA's conclusion that Deseret Power should qualify for exemption remains unchanged.

From response #8.b:

In SOB subsection VIII.C.5, revised the SO_2 values in the table retitled "Background Pollutant Concentration Values (As Corrected by EPA for SO_2)," to reflect a 29% increase in Bonanza Unit 1's SO_2 emissions since the 1991-1993 period.

In SOB subsection VIII.E.1.a, revised the "Background Concentration" in the table retitled "NAAQS Compliance Demonstration for WCFU Project Sources (Results as Corrected by EPA for SO_2)," to reflect a 29% increase in Bonanza Unit 1's SO_2 emissions since the 1991-1993 period.

In SOB subsection VIII.E.1.b, revised the "Background Concentration" in the table retitled "NAAQS Compliance Demonstration for Full Impact Area Sources (Results as Corrected by EPA for SO_2)." to reflect a 29% increase in Bonanza Unit 1's SO_2 emissions since the 1991-1993 period.

EPA's conclusion that the NAAQS and the PSD Class II increments will not be exceeded remains unchanged.

From response #9:

In SOB subsection VIII.E.3, incorporated EPA's cumulative PSD Class I increment consumption screening analysis on nearby mandatory Federal Class I areas, as described in response #9. EPA's conclusion that Class I increment will not be exceeded or threatened remains unchanged.

From response #14:

In SOB subsection VI.Q.6, added a clarifying statement that if any visible emissions are observed in a quarterly observation at a baghouse or vent filter, the frequency of observation at that baghouse or vent filter shall return to monthly.

Other minor changes made to the draft SOB:

In SOB section III, "Public Notice, Comments, Hearings and Appeals," added a citation to public comments that were received. Also added a statement that the final WCFU permit, responses to public comments, final Statement of Basis, and Administrative Record of permit-related correspondence, will be available on EPA website. Also added a statement that since commenters requested changes in the draft permit, the effective date of the final permit is thirty days after permit issuance, unless the permit is appealed.

In SOB subsection V.C, "Application Submittals and Addendums," added citation of two e-mails dated April 5, 2007 from Deseret Power, which constituted additional amendments to their PSD permit application of November 1, 2004.

In SOB subsection VI.D.1, corrected an error in the calculated annual cost of using waste coal. (The corrected cost is $6 million/year.) Made corresponding corrections in the table titled, "Annualized Cost of Potential Emission Reductions if Run-of-Mine Coal is Used Rather Than Waste Coal for Deseret Power's Proposed WCFU."

Added document listings to Appendix A, to cover the period from June 13, 2006 until issuance of the final permit, and retitled the appendix, "List of Documents in the Administrative Record for Issuance of Federal PSD Permit #PSD-OU-0002-04.00."

MONTANA AIR QUALITY PERMIT

Issued To:	Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station 3521 Gabel Road, Suite 5 Billings, MT 59102	Permit: #3423-00 Application Complete: 5/16/06 Preliminary Determination Issued: 3/30/06 Supplemental Preliminary Determination Issued: 6/22/06 Department's Decision Issued: 05/11/07 Permit Final: 05/30/07 AFS #013-0038

An air quality permit, with conditions, is hereby granted to Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Permitted Equipment

SME-HGS operates a gross 270-megawatt (MW) electrical power generating plant. The SME-HGS facility is a coal-fired steam/electric generating station incorporating a circulating fluidized bed boiler (CFB Boiler). Auxiliary power to operate the facility is estimated to be approximately 20 MW resulting in an approximate net power production capacity of 250 MW. Emissions from the CFB-Boiler are controlled by CFB limestone injection technology, a fabric filter baghouse (FFB), a hydrated ash re-injection system (HAR), and a selective non-catalytic reduction unit (SNCR). The total CFB-Boiler emission control strategy is characterized as an integrated emission control system (IECS). A complete list of permitted equipment/emission sources is contained in Section I.A of the permit analysis to this permit.

B. Plant Location

The SME-HGS plant encompasses approximately 720 acres of property and is located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 497 kilometers (km), and Northing 5,268 km. The site elevation is approximately 3,290 feet above sea level.

C. Current Permit Action

The Department of Environmental Quality (Department) issued its preliminary determination on air quality Permit #3423-00 on March 30, 2006, and accepted comments on the preliminary determination through May 1, 2006. Further, on April 25, 2006, Bison Engineering, Inc., on behalf of SME-HGS, verbally notified the Department of additional emitting units that were not previously analyzed and permitted under the preliminary determination and were deemed necessary for the construction and operation of the CFB Boiler. Specifically, SME-HGS determined that during the CFB Boiler construction phase and periodically thereafter, as necessary, SME-HGS would need to operate portable/ temporary propane-fired heaters for the purpose of curing the CFB Boiler refractory brick. SME-HGS submitted an application for the proposed additional emitting units on May 16, 2006, and the Department issued a supplemental preliminary determination on Permit

#3423-00 to include the new units. The Department's supplemental preliminary determination was issued as an attachment to the Draft Environmental Impact Statement (DEIS), which was published on June 30, 2006, and was therefore subject to public comment in accordance with the applicable DEIS timeframes. The only changes to the initial preliminary determination under the supplemental preliminary determination were related to the refractory brick curing heaters and administrative errors contained in the initial preliminary determination on Permit #3423-00.

Based on comments received during the public comment period on the Department's initial preliminary determination and additional comments received on the Department's supplemental preliminary determination during the DEIS comment period, the Department's final decision on Permit #3423-00 includes the following changes:

- Modification of the mercury emission control requirements contained in Section II.C.14.b to require installation of activated carbon injection (ACI) control technology, or an equivalent technology (equivalent in removal efficiency), prior to commencement of commercial operations and operation of ACI, or an equivalent technology (equivalent in removal efficiency), after a 6 month IECS operational period.
- Modification of the CFB Boiler Start-Up and Shutdown Plan contained in Attachment 3 to Permit #3423-00.
- Modification of CFB Boiler Start-Up and Shutdown requirements contained in Section II.B.1 to allow for future changes to the *CFB Boiler Start-Up and Shutdown Procedures* contained in Attachment 3, upon written approval of the Department.
- Removal of the Start-Up and Shutdown CO emission limit of 194 lb/hr. The BACT-determined CO emission limit of 0.10 lb/MMBtu contained in Section II.C.8 is applicable during Start-up and Shutdown operations and has been shown, through modeling, to be protective of the National and Montana Ambient Air Quality Standards (NAAQS and MAAQS).
- Modification of Section II.B.3 to include propane as an allowable CFB Boiler start-up and shutdown fuel. The SME-HGS application for air quality permit did not specifically propose propane as an allowable start-up and shutdown fuel for the CFB Boiler. However, based on the analysis of fuel oil, natural gas, and propane provided by SME-HGS for Auxiliary Boiler operations, the Department believes that propane is a relatively clean burning fuel and is therefore a suitable fuel for CFB Boiler start-up and shutdown operations.
- Modification of the language contained in Section II.E.2 to clarify the applicable BACT-determined emission control requirements for the affected material handling transfer points.
- Modification of the source testing schedule for material handling baghouses DC1 through DC5 based on Department source testing schedule guidance using Department-updated uncontrolled emission estimates for the affected units.
- Removal of the term "belt" from the conveyor transfer requirement in Section II.E.5.
- Modification of Section II.F.3 to remove the requirement that all limestone haul trucks be "covered" during transport. The Department determined that the covering of such trucks does not constitute BACT in this case.
- Removal of the language "…for transfer to the on-site ash monofill/landfill" from Section II.G.4, as this language does not constitute an air quality requirement.
- Inclusion of the language "…by manufacturer's design…" to Section II.K.2, because the existing condition contained in the Department's preliminary determination on Permit #3423-00 was not practically enforceable, as written.

- Removal of the language "…or according to another testing/monitoring schedule as may be approved by the Department in writing" from Section II.N.1.a, b, d, and f, as the Department does not have the authority to require a less stringent testing schedule than that required under 40 CFR Part 60.
- Inclusion of the language "…SME-HGS may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained" to Section II.N.1.a, d, f, and j.
- Inclusion of 40 CFR Part 60, Appendix B, Performance Specification #12A, to Section II.P.3.
- Modification of Section III.H, Construction Commencement, to require that construction commence within 18 months of permit issuance.
- Correction of various administrative errors contained in the initial and supplemental preliminary determination(s) on Permit #3423-00.
- Update to the Ambient Impact Analysis contained in Section VI of Permit Analysis to include modeling based on the proposed change in plant footprint to mitigate impacts to the Lewis and Clark historical portage recognized through EIS process. Modeling is included for both the original and the alternative footprint.
- Removal of all requirements and references to the Acid Rain Program under 40 CFR Parts 72-78. While SME-HGS is subject to the applicable requirements of the Acid Rain Program, the program is implemented under Title V of the Federal Clean Air Act. Therefore, the Department does not have the authority to include Acid Rain Program provisions in Permit #3423-00.

SECTION II: Conditions and Limitations

A. General Plant Requirements

1. SME-HGS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and ARM 17.8.752).

2. SME-HGS shall not cause or authorize emissions to be discharged into the atmosphere from haul roads, access roads, parking lots, or the general plant property without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308 and ARM 17.8.752).

3. SME-HGS shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.2 (ARM 17.8.752).

4. SME-HGS shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of airborne particulate matter are taken. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.308 and ARM 17.8.752).

5. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Da (ARM 17.8.340 and 40 CFR 60, Subpart Da).

6. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Db (ARM 17.8.340 and 40 CFR 60, Subpart Db).

7. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Y (ARM 17.8.340 and 40 CFR 60, Subpart Y).

8. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart OOO (ARM 17.8.340 and 40 CFR 60, Subpart OOO).

9. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 63, Subpart DDDDD, Industrial/Commercial/Institutional/ boiler and Process Heater MACT (ARM 17.8.342 and 40 CFR 63, Subpart DDDDD).

10. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 63, Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE) MACT (ARM 17.8.342 and 40 CFR 63, Subpart ZZZZ).

11. SME-HGS shall obtain a written coal analysis that is representative of each load of coal received from each coal supplier. The analysis shall contain, at a minimum, sulfur content, ash content, Btu value (Btu/lb), mercury content, and chlorine content (ARM 17.8.749).

12. SME-HGS shall obtain a written fuel oil analysis for each shipment of fuel oil received from each fuel oil supplier. The analysis shall contain, at a minimum, the sulfur content of the fuel oil and the vapor pressure of the fuel oil (ARM 17.8.749).

B. CFB Boiler Start-Up and Shutdown Operations

1. CFB start-up and shutdown operations shall be conducted as described in the *CFB Boiler Start-Up and Shutdown Procedures* included in Attachment 3 of Permit #3423-00 or according to another start-up and shutdown plan as may be approved by the Department in writing (ARM 17.8.749 and ARM 17.8.752).

2. CFB Boiler start-up operations, as described in Attachment 3, shall not exceed 48 hours from initial fuel feed to the CFB Boiler (ARM 17.8.749).

3. During start-up and shutdown operations, the CFB Boiler shall combust only coal with a sulfur content less than or equal to 1% sulfur by weight, fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight, propane, or pipeline quality natural gas (ARM 17.8.752).

4. During start-up and shutdown operations, oxides of nitrogen (NO_x) emissions from the CFB Boiler stack shall not exceed 388 lb/hr (ARM 17.8.749 and ARM 17.8.752).

C. CFB Boiler

1. The CFB Boiler shall combust only coal with a sulfur content less than or equal to 1% sulfur by weight except during periods of start-up or shutdown (ARM 17.8.749 and ARM 17.8.752).

2. SME-HGS shall operate an IECS including CFB limestone injection technology, HAR technology, an SNCR unit, and a FFB for CFB Boiler emissions control except as specified in Attachment 3 during start-up and shutdown operations (ARM 17.8.752).

3. SME-HGS shall not cause or authorize to be discharged into the atmosphere from the CFB Boiler stack any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Da).

4. Filterable particulate matter (filterable PM) emissions from the CFB Boiler stack shall be limited to 0.012 lb/MMBtu and 33.25 lb/hr (ARM 17.8.752).

5. Particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) emissions (filterable and condensable) from the CFB Boiler stack shall be limited to 0.026 lb/MMBtu and 72.04 lb/hr (ARM 17.8.752).

6. The CFB Boiler's PM_{10} emission limit shall be used as a surrogate emission limit for radionuclides and trace metals (ARM 17.8.752).

7. Except during periods of start-up and shutdown, NO_x emissions from the CFB Boiler stack shall not exceed the following:

   a. 0.10 lb/MMBtu based on a 1-hour average (ARM 17.8.749 and ARM 17.8.752);

   b. 0.09 lb/MMBtu based on a 24-hour average (ARM 17.8.749 and ARM 17.8.752); and

   c. 0.07 lb/MMBtu based on a rolling 30-day average (ARM 17.8.752).

8. CO emissions from the CFB Boiler stack shall be controlled by proper boiler design and good combustion practices. CO emissions from the CFB Boiler stack shall not exceed 0.10 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

9. Sulfur dioxide (SO_2) emissions from the CFB Boiler stack shall not exceed the following:

   a. 0.057 lb/MMBtu based on a 3-hour average (ARM 17.8.749 and ARM 17.8.752);

   b. 0.048 lb/MMBtu based on a 24-hour average (ARM 17.8.749 and ARM 17.8.752); and

   c. 0.038 lb/MMBtu based on a rolling 30-day average (ARM 17.8.752).

10. Volatile Organic Compounds (VOC) emissions from the CFB Boiler stack shall be controlled by proper boiler design and good combustion practices. VOC emissions from the Boiler stack shall not exceed 0.003 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

11. Hydrochloric acid (HCl) emissions from the CFB Boiler stack shall not exceed 0.0021 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

12. Hydrofluoric acid (HF) emissions from the CFB Boiler stack shall not exceed 0.0017 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

13. Sulfuric Acid (H_2SO_4) mist emissions from the CFB Boiler stack shall not exceed 0.0054 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

14. Mercury Emissions

    a. Following commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), mercury emissions from the CFB Boiler shall not exceed 0.0000015 lb/MMBtu (1.5 pounds per trillion Btu (lb/TBtu)) based on a rolling 12-month average, or an emission rate equal to a 90% or greater reduction of mercury in the as-fired coal, as measured in lb/TBtu and based on a rolling 12-month average. Mercury emissions from the CFB Boiler shall be controlled by the IECS or, at SME-HGS's request and as may be approved by the Department in writing, an equivalent technology (equivalent in removal efficiency) (ARM 17.8.752).

    b. Prior to commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), SME-HGS shall install an activated carbon injection (ACI) control system or, at SME-HGS's request and as may be approved by the Department in writing, an equivalent technology (equivalent in removal efficiency). Within 6 months after commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), SME-HGS shall operate the ACI control system, or an equivalent technology (equivalent in removal efficiency) (ARM 17.8.749).

15. Heat input to the CFB-Boiler shall not exceed 2771 MMBtu/hr based on a 24-hour daily average and 23,004,636 MMBtu during any rolling 12-month time period (ARM 17.8.749).

16. The CFB Boiler stack height shall be maintained at a height of at least 400 feet above ground level (ARM 17.8.749).

D. Auxiliary Boiler

1. The Auxiliary Boiler shall be limited to 850 hours of operation during any rolling 12-month time period (ARM 17.8.752 and 40 CFR 60, Subpart Db).

2. The Auxiliary Boiler shall combust only fuel-oil with a sulfur content less than or equal to 0.05% sulfur by weight, propane, or pipeline quality natural gas (ARM 17.8.752).

3. SO_2 emissions from the Auxiliary Boiler shall be limited to 12.63 lb/hr (ARM 17.8.749).

4. NO_x emissions from the Auxiliary Boiler shall be controlled by the installation and operation of dry low-NO_x (DLN) burners. NO_x emissions from the Auxiliary Boiler shall be limited to 46.80 lb/hr (ARM 17.8.749 and ARM 17.8.752).

5. CO emissions from the Auxiliary Boiler shall be controlled by proper boiler design and operation and good combustion practices. CO emissions from the Auxiliary Boiler shall be limited to 18.60 lb/hr (ARM 17.8.749 and ARM 17.8.752).

6. VOC emissions from the Auxiliary Boiler shall be controlled by proper boiler design and operation and good combustion practices (ARM 17.8.752).

7. PM_{10} emissions from the Auxiliary Boiler shall be limited to 3.20 lb/hr (ARM 17.8.749).

8. The Auxiliary Boiler stack height shall be maintained at a height of at least 220 feet above ground level (ARM 17.8.749).

E. Coal Fuel Processing, Handling, Transfer, and Storage Operations

1. Visible emissions from any Standards of Performance for New Stationary Source (NSPS)-affected equipment shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Y).

2. All conveyors shall be enclosed or covered and all outdoor conveyor transfer points shall be covered and vented to a FFB or bin vent, except the following transfer points shall be controlled by wet dust suppression and any other necessary reasonable precautions (ARM 17.8.752):

   - Conveyor CC01 to Emergency Coal Pile;
   - Fly-ash Pug Mill 1 to Truck Load-out;
   - Fly Ash Truck Transport to On-site Ash Disposal Area;
   - Bed Ash Pug Mill 2 to Truck Load-Out; and
   - Bed Ash Truck Transport to On-site Ash Disposal Area.

3. All railcar coal deliveries/transfers shall be unloaded within the Rail Unloading Building via belly-dump to a below grade hopper. The Railcar Unloading Building shall be vented to FFB DC1 and maintained under constant negative pressure when coal is being unloaded and conveyed within the building (ARM 17.8.752).

4. PM_{10} emissions from FFB DC1 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

5. All coal deliveries to the Railcar Unloading Building shall be transferred via below ground feeders to a conveyor (MC02) (ARM 17.8.752).

6. Transfer Tower 16 shall be enclosed and vented to FFB DC2 (ARM 17.8.752).

7. PM_{10} emissions from FFB DC2 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

8. The emergency coal pile shall be compacted and sprayed with water and/or chemical dust suppressant, as necessary, to maintain compliance with the reasonable precautions requirement and opacity limits (ARM 17.8.752).

9. Coal Silo (CS-1) shall be enclosed and vented to FFB DC2 (ARM 17.8.752).

10. The Coal Crusher House shall be vented to FFB DC3 and shall be maintained under constant negative pressure when processing coal (ARM 17.8.752).

11. The coal crushers (2), surge bin, and rotary feeders (2) shall be enclosed within the Coal Crusher House and vented to FFB D3 (ARM 17.8.752).

12. PM_{10} emissions from FFB D3 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

13. All coal transfers through the tripper system to the day bins located in the CFB Boiler house shall be enclosed and routed to FFB DC4 (ARM 17.8.752).

14. PM_{10} emissions from FFB DC4 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

F. Limestone and Lime Material Processing, Handling, Transfer, and Storage Operations

1. Visible emissions from any NSPS-affected crusher shall not exhibit an opacity of 15% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

2. Visible emissions from any other NSPS-affected equipment, such as screens or conveyor transfers, shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

3. All limestone material shall be delivered to the facility via bottom dumping haul-trucks and unloaded within a limestone material unloading drive-through building. The limestone material unloading drive-through building shall be maintained under constant negative pressure and vented through FFB DC5 when limestone material is being unloaded and conveyed within the drive-through building (ARM 17.8.752).

4. All conveyors shall be covered and all outdoor conveyor transfer points shall be covered and vented to FFB DC5 (ARM 17.8.752).

5. All limestone material transfers to the Bucket Elevator and the Limestone Silo shall be vented to FFB DC5 (ARM 17.8.752).

6. PM_{10} emissions from FFB DC5 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

7. Visible emissions from FFB DC5 shall not exhibit an opacity of greater than 7% averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

G. Fly and Bottom-Ash Material Processing, Handling, Transfer, and Storage Operations

1. Fly-ash shall be pneumatically transferred from the CFB Boiler FFB to the Fly-Ash Silo (AS1) (ARM 17.8.752).

2. Bed-ash shall be pneumatically transferred from the CFB Boiler to the Bed-Ash Silo (AS2) (ARM 17.8.752).

3. PM_{10} emissions resulting from the charging of AS1 and AS2 shall be controlled by fabric filter Bin vents DC6 and DC7, respectively (ARM 17.8.752).

4. Fly-ash and bed-ash shall be gravity-fed into haul trucks through a wet pug-mill (ARM 17.8.752).

5. Air displaced by ash loading into haul trucks shall be vented through AS1 and AS2 and associated bin vents DC6 and DC7, respectively (ARM 17.8.752).

6. PM_{10} emissions from each bin vent DC6 and DC7 shall be limited to 0.01 gr/dscf (ARM 17.8.752).

7. Visible emissions from bin vent DC6 and DC7 shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.752).

H. Coal Thawing Shed Operations

1. The Coal Thawing Shed Heater shall be limited to 240 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Coal Thawing Shed Heater shall combust only propane or pipeline quality natural gas (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Coal Thawing Shed Heater operations shall be controlled by proper design and operation, good combustion practices, and the combustion of propane or pipeline quality natural gas only (ARM 17.8.752).

I. Emergency Fire Pump Operations

1. The Emergency Fire Pump shall be limited to 500 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Emergency Fire Pump shall combust only fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Emergency Fire Pump shall be controlled by proper design and operation and good combustion practices (ARM 17.8.752).

J. Emergency Generator Operations

1. The Emergency Generator shall be limited to 500 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Emergency Generator shall combust only fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Emergency Generator shall be controlled by proper design and operation and good combustion practices (ARM 17.8.752).

4. NO_x emissions from the Emergency Generator shall be limited to 41.20 lb/hr (ARM 17.8.749 and ARM 17.8.752).

5. CO emissions from the Emergency Generator shall be limited to 2.70 lb/hr (ARM 17.8.749 and ARM 17.8.752).

K. Cooling Tower

1. PM_{10} emissions from the Cooling Tower shall be controlled by drift eliminators (ARM 17.8.752).

2. The Cooling Tower drift rate shall be limited to 0.002% of the total circulating water flow, by manufacturer's design (ARM 17.8.752).

L. Fuel Storage Tank

SME-HGS shall not store any liquid fuel with a vapor pressure greater than 3.5 kilopascals (kPa) in the 275,000-gallon capacity fuel storage tank (ARM 17.9.749).

M. CFB Boiler Refractory Brick Curing Heaters

1. SME-HGS shall operate the CFB Boiler refractory brick curing heater(s) only for the purpose of curing CFB Boiler refractory brick. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum of 320 hours of operation during any rolling 12-month time period (ARM 17.8.752).

2. The CFB Boiler refractory brick curing heaters shall combust propane fuel only (ARM 17.8.752).

3. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum heat input capacity of 2771 MMBtu/hr (ARM 17.8.749).

4. SME-HGS shall not operate the CFB Boiler refractory brick curing heater(s) when electricity is being generated through CFB Boiler operations or when the boiler fuel feed (diesel or coal) is operational (ARM 17.8.749).

N. Testing Requirements

1. CFB Boiler Testing Requirements

a. SME-HGS shall initially test the CFB Boiler for opacity within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the continuous opacity monitoring system (COMS) to monitor compliance with the applicable opacity limit (ARM 17.8.749).

b. SME-HGS shall initially test the CFB Boiler for filterable PM emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

c. SME-HGS shall initially test the CFB Boiler for PM_{10} (filterable and condensable) emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/ monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

d. SME-HGS shall initially test the CFB Boiler for NO_x emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler. SME-HGS shall conduct the initial performance source testing for NO_x and CO, concurrently. SME-HGS may use testing in conjunction with the Relative Accuracy Test completed for certification of the continuous emissions monitoring system (CEMS), as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the NO_x CEMS to monitor compliance with the applicable NO_x emission limits (ARM 17.8.105 and ARM 17.8.749).

e. SME-HGS shall initially test the CFB Boiler for CO emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing. SME-HGS shall conduct the initial performance source testing for CO and NO_x, concurrently (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and 17.8.749).

f. SME-HGS shall initially test the CFB Boiler for SO_2 emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler. SME-HGS may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the SO_2 CEMS to monitor compliance with the applicable SO_2 emission limits (ARM 17.8.749).

g. SME-HGS shall initially test the CFB Boiler for HCl emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

h. SME-HGS shall initially test the CFB Boiler for HF emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and 17.8.749).

i. SME-HGS shall initially test the CFB Boiler for H_2SO_4 emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

j. SME-HGS shall monitor compliance with the applicable mercury emission limit(s) pursuant to 40 CFR 60.48a through 60.52a and 40 CFR 75, Subpart I. Any mercury CEMS used must be operated in compliance with 40 CFR 60, Appendix B. SME-HGS may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105, ARM 17.8.749, 40 CFR 60, Subpart Da, and 40 CFR 75, Subpart I)

2. Coal Fuel, Limestone, and Ash Processing, Handling, Transfer, and Storage Operations Testing Requirements

a. Compliance with the opacity limit for FFB DC1, controlling emissions from rail unloading material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

b. Compliance with the PM_{10} emission limit for FFB DC1 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every-5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

c. Compliance with the opacity limit for FFB DC2, controlling emissions from coal silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

d. Compliance with the PM_{10} emission limit for FFB DC2 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

e. Compliance with the opacity limit for FFB DC3, controlling emissions from coal crusher material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

f. Compliance with the PM_{10} emission limit for FFB DC3 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

g. Compliance with the opacity limit for FFB DC4, controlling emissions from tripper deck plant silos material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y and Subpart OOO).

h. Compliance with the PM_{10} emission limit for FFB DC4 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 5-year basis, or

according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y and Subpart OOO).

i. Compliance with the opacity limit for FFB DC5, controlling emissions from limestone material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart OOO).

j. Compliance with the PM_{10} emission limit for FFB DC5 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart OOO).

k. Compliance with the opacity limit for bin vent DC6, controlling emissions from ash silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105 and ARM 17.8.749).

l. Compliance with the opacity limit for bin vent DC7, controlling emissions from ash silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105 and ARM 17.8.749)

3. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

4. The Department may require further testing (ARM 17.8.105).

O. Operational Reporting Requirements

1. SME-HGS shall submit to the Department annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. SME-HGS shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or that would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, at least 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information required in ARM 17.8.745(1)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by SME-HGS as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

4. SME-HGS shall document, by month, the total heat input to the CFB Boiler. By the 25th day of each month, SME-HGS shall total heat input to the CFB Boiler for the previous month. The monthly information will be used to verify compliance with the rolling 12-month boiler heat input limitation (ARM 17.8.749).

5. SME-HGS shall document, by month, the hours of operation of the Auxiliary Boiler. By the 25th day of each month, SME-HGS shall total the operating hours of the Auxiliary Boiler for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

6. SME-HGS shall document, by month, the hours of operation of the Emergency Generator. By the 25th day of each month, SME-HGS shall total the operating hours of the Emergency Generator for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

7. SME-HGS shall document, by month, the hours of operation of the Emergency Fire Water Pump. By the 25th day of each month, SME-HGS shall total the operating hours of the Emergency Fire Water Pump for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

8. SME-HGS shall document, by month, the hours of operation of the Coal Thawing Shed Heater. By the 25th day of each month, SME-HGS shall total the operating hours of the Coal Thawing Shed Heater for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

9. SME-HGS shall maintain on site the coal fuel and fuel oil analyses required under Section II.A and submit this information to the Department upon request (ARM 17.8.749).

10. SME-HGS shall maintain a record of CFB Boiler start-up operations. SME-HGS shall document the total start-up operating hours from initial fuel feed to the CFB Boiler for each start-up period. The information shall be submitted to the Department upon request. The information will be used to monitor compliance with the CFB Boiler start-up operating hour limit (ARM 17.8.749).

11. SME-HGS shall monitor and analyze the CFB Boiler mercury control performance data following commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH). By the 25th day of each month, SME-HGS shall summarize the applicable mercury emissions data (percent reduction and/or emission rate). SME-HGS shall submit this information to the Department quarterly, or according to another reporting schedule as may be approved by the Department in writing. The information will be used to verify the IECS mercury control capabilities (ARM 17.8.749).

12. SME-HGS shall document, by month, the hours of operation of the refractory brick curing heaters. By the 25th day of each month, SME-HGS shall total the operating hours of the refractory brick curing heaters for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

P. Continuous Emissions Monitoring Systems (CEMS/COMS)

1. SME-HGS shall install, operate, calibrate, and maintain CEMS as follows:

   a. A CEMS for the measurement of SO_2 shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   b. A flow monitoring system to complement the SO_2 monitoring system shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   c. A CEMS for the measurement of NO_x shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   d. A COMS for the measurement of opacity shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   e. A CEMS for the measurement of oxygen (O_2) or carbon dioxide (CO_2) content shall be operated on the CFB-Boiler stack (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

   f. A continuous monitoring methodology for the measurement of mercury shall be operated on the CFB-Boiler stack (ARM 17.8.105 and ARM 17.8.749).

2. All continuous monitors required by this permit and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance tests conducted in accordance with the requirements of 40 CFR Part 60, Subpart A; 40 CFR Part 60, Subpart Da; 40 CFR Part 60, Appendix B (Performance Specifications #1, #2, #3, and #12A) (ARM 17.8.749 and 40 CFR 60).

3. On-going quality assurance for the gas CEMS must conform to 40 CFR Part 60, Appendix F (ARM 17.8.749).

4. SME-HGS shall inspect and audit the COMS annually, using neutral density filters. SME-HGS shall conduct these audits using the applicable procedures and forms in the EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors (EPA-450/4-92-010, April 1992). The results of these inspections and audits shall be included in the quarterly excess emission report (ARM 17.8.749).

5. SME-HGS shall maintain a file of all measurements from the CEMS, and performance testing measurements: all CEMS performance evaluations; all CEMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The records shall be retained on site for at least 5 years following the date of such measurements and reports. SME-HGS shall supply these records to the Department upon request (ARM 17.8.749).

6. SME-HGS shall maintain a file of all measurements from the COMS, and performance testing measurements: all COMS performance evaluations; all COMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The records shall be retained on site for at least 5 years following the date of such measurements and reports. SME-HGS shall supply these records to the Department upon request (ARM 17.8.749).

Q. Notification

1. Within 30 days after commencement of construction of the SME-HGS facility, SME-HGS shall notify the Department of the date of commencement of construction (ARM 17.8.749).

2. Within 30 days after commencement of construction of the CFB Boiler, SME-HGS shall notify the Department of the date of commencement of construction (40 CFR Part 60.7 and ARM 17.8.749).

3. Within 15 days after actual startup of the CFB Boiler, SME-HGS shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).

4. Within 30 days after commencement of construction of the Auxiliary Boiler, SME-HGS shall notify the Department of the date of commencement of construction (40 CFR Part 60.7 and ARM 17.8.749).

5. Within 15 days after actual startup of the Auxiliary Boiler, SME-HGS shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).

6. Within 30 days after commencement of construction of material handling/processing fabric filter baghouses DC1, DC2, DC3, DC4, and DC5, SME-HGS shall notify the Department of the date of commencement of construction of the affected fabric filter baghouse(s) (40 CFR 60.7 and ARM 17.8.749).

7. Within 15 days after actual startup of material handling/processing fabric filter baghouses DC1, DC2, DC3, DC4, and DC5, SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter baghouse(s) (40 CFR 60.7 and ARM 17.8.749).

8. Within 30 days after commencement of construction of the ash silo fabric filter bin vents DC6 and DC7, respectively, SME-HGS shall notify the Department of the date of commencement of construction of the affected fabric filter bin vent(s) (ARM 17.8.749).

9. Within 15 days after actual startup of the ash silo fabric filter bin vents DC6 and DC7, respectively, SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter bin vent(s) (ARM 17.8.749).

10. Within 30 days after commencement of construction of the CFB Boiler refractory brick curing heater(s), SME-HGS shall notify the Department of the date of commencement of construction of the affected unit(s) and provide the maximum heat input capacity of the affected unit(s) (ARM 17.8.749).

11. Within 15 days after actual startup of the CFB Boiler refractory brick curing heater(s), SME-HGS shall notify the Department of the date of actual startup of the affected unit(s) (ARM 17.8.749).

SECTION III: General Conditions

A. Inspection – SME-HGS shall allow the Department's representatives access to the facility at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS, COMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if SME-HGS fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving SME-HGS of the responsibility for complying with any applicable federal or Montana statute or rule, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement – Violations of requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq*., MCA, and ARM 17.8.763.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure by SME-HGS to pay the annual operation fee may be grounds for revocation of this permit, as allowed by that section and rules adopted thereunder by the Board.

H. Construction Commencement – Construction must begin within 18 months after permit issuance and proceed with due diligence until the project is complete or Permit #3423-00 shall expire. If the permit expires, SME-HGS shall not commence construction until SME-HGS has applied for and received a new air quality permit pursuant to Sections 75-2-204 and 75-2-211, Montana Code Annotated, and ARM 17.8.740 *et seq*., as amended (ARM 17.8.762).

Attachment 2

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS (EER)

PART 1 Complete as shown. Report total time during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit start up, shut down, malfunctions, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as:

(1 – (total hours of excess emissions during reporting period / total hours of CEMS availability during reporting period)) x 100

PART 2 Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit start up, shut down, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as:

(1–(CEMS downtime in hours during the reporting period[a] /total hours of point source operation during reporting period)) x 100

a - All time required for calibration and to perform preventative maintenance must be included in the CEMS downtime.

PART 3 Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TR units, energizers for electrostatic precipitators (ESP); pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.

PART 4 Use Table I as a guideline to report <u>all</u> excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.

PART 5 Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.

PART 6 Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.

PART 7 Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.

PART 8 Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 8.

Attachment 2

EXCESS EMISSIONS REPORT

PART 1 – General Information

a. Emission Reporting Period _____

b. Report Date _____

c. Person Completing Report _____

d. Plant Name _____

e. Plant Location _____

f. Person Responsible for Review
and Integrity of Report _____

g. Mailing Address for 1.f. _____

_____

h. Phone Number of 1.f. _____

i. Total Time in Reporting Period _____

j. Total Time Plant Operated During Quarter _____

k. Permitted Allowable Emission Rates: Opacity _____

SO_2 _____ NO_x _____ TRS _____ _____

l. Percent of Time Out of Compliance: Opacity _____

SO_2 _____ NO_x _____ TRS _____ _____

m. Amount of Product Produced
During Reporting Period _____

n. Amount of Fuel Used During Reporting Period _____

PART 2 - Monitor Information: Complete for each monitor.

a. Monitor Type (circle one)

Opacity SO_2 NO_x O_2 CO_2 TRS Flow

b. Manufacturer _____

c. Model No. _____

d. Serial No. _____

e. Automatic Calibration Value: Zero_____ Span _____

f. Date of Last Monitor Performance Test _____

g. Percent of Time Monitor Available:

1) During reporting period _____

2) During plant operation _____

h. Monitor Repairs or Replaced Components Which Affected or Altered Calibration Values _____

i. Conversion Factor (f-Factor, etc.) _____

j. Location of monitor (e.g. control equipment outlet)_____

PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant.)

a. Pollutant (circle one):

Opacity SO_2 NO_x TRS

b. Type of Control Equipment _____

c. Control Equipment Operating Parameters (i.e., delta P, scrubber water flow rate, primary and secondary amps, spark rate)

_____

d. Date of Control Equipment Performance Test _____

e. Control Equipment Operating Parameter During Performance Test

_____

_____

_____

_____

PART 4 - Excess Emission (by Pollutant)

Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

PART 5 - Continuous Monitoring System Operation Failures

Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

PART 6 - Control Equipment Operation During Excess Emissions

Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

PART 7 - Excess Emissions and CEMS performance Summary Report

Use Table IV: Complete one sheet for each monitor.

PART 8 - Certification for Report Integrity, by person in 1.f.

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

SIGNATURE _____

NAME _____

TITLE _____

DATE _____

Attachment 2

TABLE I

EXCESS EMISSIONS

Date	Time From	Time To	Duration	Magnitude	Explanation/Corrective Action

Attachment 2

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time From	Time To	Duration	Problem/Corrective Action

Attachment 2

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

Date	Time From	Time To	Duration	Operating Parameters	Corrective Action

Attachment 2

TABLE IV

Excess Emission and CEMS Performance Summary Report

Pollutant (circle one): SO_2 NO_x TRS H_2S CO Opacity

Monitor ID

Emission data summary [1]	**CEMS performance summary** [1]
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \quad\right]$	1. CEMS[2] downtime in reporting due to: a. Monitor equipment malfunctions b. Non-monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CEMS downtime 3. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \quad\right]$

[1] For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)
[2] CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

Attachment 3
CFB Boiler Start-Up and Shutdown Procedures
Permit #3423-00

CFB Boiler start-up and shutdown operations shall be conducted as described in this attachment.

I. CFB Boiler Start-Up Operations

Startup of a circulating fluidized bed (CFB) boiler is a three-phase operation that can take up to 48 hours depending on the initial furnace temperature and conditions of the fluidized bed. During the three-phase startup process, the unit steps through a series of changes to reach full load firing on coal with the addition of limestone into the CFB furnace. During this process, particulate mater (PM), oxides of nitrogen (NO_x), and sulfur dioxide (SO_2) emissions may vary until air pollution control equipment can be operated at a minimum continuous load.

A. Phase 1 - CFB Boiler Bed Material Preparation

Phase 1, the first step in the startup of a CFB, involves loading the initial bed material into the furnace. Either sand or used bed ash is loaded into the bed utilizing a pneumatic system. This step can take several hours to complete, during which time there is no fuel combustion taking place. The emissions present during the ash loading cycle are particulate matter. The fabric filter baghouse will not be operational during this first phase; however, entrained particulate matter is expected to remain within the boiler.

B. Phase 2 – Introduction of Startup Fuel

Introduction of startup fuel in Phase 2 is estimated to take approximately 12 hours. Once the bed material is loaded into the furnace, the fans are started and the CFB boiler begins to fire on the startup fuel. The startup fuel is utilized to warm the bed material and the CFB Boiler components. Startup fuel use is increased until the temperature inside the cyclone reaches approximately 1150°F. From a cold start, this process may take 14 hours or longer. During this warm-up period, NO_x is controlled through efficient low NO_x burners; SO_2 is minimized through the use of low sulfur fuels; and the exhaust bypasses the fabric filter baghouse in order not to prematurely "blind" or damage the filters and shorten the functional life of the filters. Therefore, PM emissions are uncontrolled during Phase 2 operations. Carbon monoxide (CO) emissions may be higher than full load operation due to combustion conditions in the furnace during this period. The firing is expected to be approximately 831 million British thermal units per hour (MMBtu/hr) (30% of the maximum CFB Boiler heat input rate of 2,771 MMBtu/hr).

C. Phase 3 – Introduction of Coal

Phase 3 starts after the temperature inside the cyclone reaches 1150°F and typically lasts approximately 6 hours, but may last longer. During Phase 3, coal and limestone are introduced into the furnace and the feed rate is increased over the next 2 hours until the coal becomes the primary fuel source. During this time, both startup fuel and coal are combusted together. The startup fuel feed rate is slowly reduced and is eventually shut off. During this transition, NO_x is controlled by the use of low NO_x burners and the staged combustion of the coal. SO_2 is controlled by the use of low sulfur fuels and the addition of limestone to the fluidized bed. After the start-up fuel is shut off, the exhaust is routed through the fabric filter baghouse to control particulate matter emissions.

At approximately 50% of full load the NO_x is further reduced by adding ammonia injection via the Selective Non-catalytic Reduction (SNCR) system. In addition, approximately 4 hours after the limestone is injected into the fluidized bed, the secondary flue gas desulphurization (FGD) (hydrated ash reinjection) unit is activated to further reduce SO_2 emissions. At this point in the boiler start-up process, all emissions control equipment is fully activated. Start-up operations are limited by permit to no longer than 48 hours.

II. CFB Boiler Shutdown

Several steps are required for a controlled shutdown of the boiler and the associated ancillary equipment. The first step of the process is to shut down the coal feed into the furnace. In order to accomplish this, the coal feed and firing rate is gradually reduced. As the temperature is reduced below minimum requirements for the secondary FGD (hydrated ash reinjection) and SNCR systems, these systems are turned off. The furnace is brought down to the minimum coal firing rate. At this point the coal feed is completely shut off and the furnace is purged with air. The air will be used to gradually lower the boiler temperature for inspection or maintenance. Once the boiler is cooled off, the ID Fan will be turned off. If no access into the furnace is required, the bed ash will be discharged and pneumatically conveyed to the ash silo, where it will be stored until the next startup. In the event that the boiler shutdown is only for a short period, and the re-operation of the unit is anticipated, the fans will be turned off, and the ID Fan control damper will be closed in order to bottle up the furnace and maintain the maximum amount of heat.

Permit Analysis
Southern Montana Electric Generation and Transmission Cooperative –
Highwood Generating Station
Permit #3423-00

I. Introduction/Process Description

A. Permitted Equipment

Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS) operates a net 250-megawatt (MW) electrical power generating plant located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 297.8 kilometers (km), and Northing 5,070.1 km. The site elevation is approximately 3,290 feet above sea level.

The SME-HGS facility is a coal-fired steam/electric generating station incorporating a circulating fluidized bed boiler (CFB Boiler) with an average annual heat input value of 2,626 million British thermal units per hour (MMBtu/hr) and a maximum short-term heat input capacity of 2,771 MMBtu/hr to produce approximately 1.8 million pounds of steam per hour. The steam is routed to a steam turbine, which drives an electric generator capable of producing an estimated 270 gross MW of electrical power. Auxiliary power to operate the facility is estimated to be approximately 20 MW resulting in the approximate net power production capacity of 250 MW. The following equipment/emission sources are permitted for this facility:

- 2771 MMbtu/hr heat input capacity coal fired CFB Boiler (2626 MMBtu/hr average)
- 225 MMBtu/hr heat input capacity diesel fuel-oil, propane, or natural gas fired Auxiliary Boiler
- 2000 kilowatt (kW) emergency diesel fuel-oil fired generator set
- 230 kW emergency diesel fuel-oil fired Emergency fire pump
- 40 MMBtu/hr heat input capacity propane/natural gas fired Coal Thawing Shed Heater
- Cooling Tower
- Fabric Filter Baghouse (FFB) DC1 controlling rail unloading material transfers
- FFB DC2 controlling coal silo material transfers
- FFB DC3 controlling coal crusher operation and material transfers
- FFB DC4 controlling tripper deck plant silos material transfers
- FFB DC5 controlling limestone material transfers
- Fabric Filter bin vent DC6 controlling fly ash silo (AS-1) material transfers
- Bin vent DC7 controlling bottom ash silo (AS-2) material transfers
- Emergency Coal Storage Pile
- Ash Storage/Disposal Monofill
- 275,000 gallon capacity diesel fuel-oil storage tank
- Haul Roads/vehicle traffic
- 2771 MMBtu/hr heat input capacity portable/temporary propane fired CFB Boiler refractory brick curing heater(s)

B. Source Description

1. CFB Boiler

The CFB Boiler will combust low-sulfur coal except during periods of start-up and shutdown when pipeline quality natural gas, propane, or low-sulfur diesel fuel-oil may be combusted. Regulated pollutants emitted from the CFB-Boiler will be controlled by CFB limestone injection technology, a fabric filter baghouse (FFB), a hydrated ash re-injection system (HAR), and a selective non-catalytic reduction unit (SNCR). The total CFB-Boiler emission control strategy is characterized as an integrated emission control system (IECS).

The CFB Boiler technology uses a bed of crushed coal and limestone and recycled heavy ash particles suspended (fluidized) in an upwardly flowing air stream. Air enters near the bottom of the furnace and is staged through air distribution nozzles to minimize the formation of NO_x. The coal and limestone are metered and fed into the furnace bed. Combustion takes place in the fluidized bed, which is limited in temperature to reduce the formation of NO_x. The fine particles of limestone react with the sulfur in the coal and reduce the formation of SO_2. The heavier combustion byproduct particles are carried in the flue gas through the furnace, collected in a cyclone separator, and are then circulated back into the furnace.

The SNCR system is used to control NO_x emissions. Ammonia (NH_3) is injected into the cyclone separator and mixed with the flue gas. The NH_3 reacts with the flue gas to convert NO_x into nitrogen gas (N_2), and water vapor (H_2O). The HAR system is used to control SO_2 emissions. The HAR is a dry flue gas desulfurization (FGD) process; the system mixes water with fly ash and available lime (produced during heating of the limestone in the CFB Boiler) to react with the SO_2 in the flue gas to form particulate, which is collected downstream in FFB. The FFB is used for particulate emissions control. The fabric filter consists of multiple fabric bags that capture lighter particles in the exhaust gases downstream of the cyclone separator. These lighter particles include fly ash and lighter solids created in the chemical reaction processes. Carbon monoxide (CO) and Volatile Organic Compounds (VOC) emissions will be controlled by best management practices (BMP) and staged combustion of air ensuring proper operation of the CFB Boiler. Limestone injection in the CFB Boiler and the HAR system, collectively, will also remove acid gases including sulfuric acid (H_2SO_4), hydrochloric acid (HCl) and hydrofluoric acid (HF). In addition, the FFB will reduce emissions of metals including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, mercury, and manganese. A co-benefit of mercury emission reduction will result from the overall IECS design. Absorption of mercury will be realized in the CFB Boiler due to the source of unburned carbon, use of limestone injection, SNCR, and the HAR system. The mercury in particulate form will then be collected in the FFB. In addition, mercury specific activated carbon injection (ACI) emission controls (or equivalent) must be installed prior to commencement of commercial operations and operated after a 6-month IECS operational period. After passing through the FFB, the flue gas will exit to atmosphere through the 400-feet tall CFB Boiler stack. The height of the stack was selected to minimize the visual impact of the plant while maintaining adequate dispersion.

2. Auxiliary Boiler, Emergency Generator, Emergency Fire Pump, and Coal Thawing Shed

The auxiliary boiler will combust #2 diesel fuel, natural gas, or propane and will be in operation only during periods of CFB Boiler startup, shutdown, and commissioning, and during extended downtimes of the CFB Boiler during winter months to aid in the prevention of freezing of the CFB Boiler components. The Emergency Generator and Emergency Fire Pump will combust only low-sulfur diesel fuel-oil and operate only during

emergencies and during required maintenance. The Coal Thawing Shed Heater will only operate on propane or natural gas and during times when the coal is frozen in the coal train cars.

3. Cooling Tower

A wet cooling tower will be used to dissipate the heat from the condenser by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling tower. The cooling tower will be an induced, counter flow draft design equipped with drift eliminators. The average make-up water rate for the proposed cooling tower will be approximately 2,250 gallons per minute (gpm). Water will be delivered to the facility via pipeline from the Missouri River.

4. Coal Fuel Processing, Handling, Transfer, and Storage Operations

Facility operations will utilize several proposed conveyors, transfer points, and storage facilities to handle the coal fuel material required for the operation of the CFB Boiler. The coal storage and handling system begins with coal delivered by railcars to the SME-HGS facility. Coal deliveries are estimated to be two trains per week or approximately 22,000 tons of coal per week.

The coal delivery railcars will pass through the Coal Thawing Shed, which will thaw frozen wintertime coal shipments before the railcars enter the Rail Unloading Building. Inside the Rail Unloading Building the coal railcars will be unloaded via a belly dump into a below-grade hopper. From the hopper, the coal will be transferred onto a covered belt conveyor (MC02). The Rail Unloading Building will be vented to an induced draft FFB DC1, which will maintain a constant negative pressure within the building. FFB DC1 will provide emission control for coal transfers from the below-grade feeders to conveyor MC02. MC02 will deliver the coal to the enclosed Transfer Tower 16. The Transfer Tower will be vented to the induced draft FFB DC2 located near the coal silo. The Transfer Tower will direct the coal to either the coal silo or to the outdoor long-term coal storage pile (emergency coal pile). The emergency coal pile will store enough coal to supply the CFB Boiler for approximately one month and be used during interruptions in coal deliveries. The emergency coal pile will be compacted and sprayed with water or surfactant to minimize coal dust emissions. Coal transferred to the emergency coal storage pile will be diverted to the Coal Stackout Conveyor (CC01) and will then enter the Lowering Well where emissions will be controlled by the Lowering Well design. Coal will be reclaimed from the coal storage pile by below-grade vibrating reclaim hoppers and a belt feeder. The reclaimed coal will be moved onto the Coal Reclaim Conveyor (CC03) and returned to Transfer Tower 16. Coal not directed to the emergency coal pile or reclaimed from the emergency coal pile will be transferred to the Coal Transfer Conveyor (CC02) inside Transfer Tower 16. CC02 feeds the Coal Silo (CS-1), which is sized to hold coal for several days of CFB Boiler operations. The coal transfers associated with CC04 are controlled by FFB DC2 located at the coal silo. FFB DC2 will also control coal dust emissions from the transfer of coal from the feeder located at the bottom of CS-1 to the Coal Feeder Conveyor (CC04). CC04 transfers coal to the Coal Crusher House which encloses a coal surge bin, two rotary feeders, and two coal crushers and is controlled by FFB DC3, which also controls emissions from the Coal Transfer Conveyor CC05. Crushed coal on CC06 is transferred to the Tripper System (comprised of the Tripper Conveyor and Traveling Tripper) and is controlled by FFB DC4.

5. Limestone Processing, Handling, Transfer, and Storage Operations

Covered, over-the-highway, bottom-dumping trucks will deliver limestone material to the SME-HGS facility and will be unloaded in a drive-through building, which is controlled by FFB DC5. The Limestone Transfer Conveyor (LC01) will move the delivered limestone to the Limestone Bucket Elevator (LC02), and discharge into the Limestone Silo (LS1). LS1 loading and unloading limestone dust emissions from this silo will also be controlled by FFB DC5. Limestone unloaded from the silo will be transferred to a feed chute by the Limestone Weight Feeder (LC03). The feed chute dumps directly into the Limestone Mills, which feed directly into the furnace of the boiler.

6. Fly and Bed Ash Handling, Transfer, and Storage/Disposal Operations

Combustion of coal in the CFB Boiler will produce two types of dry ash: bed ash (20-30%) and fly ash (70-80%). Both fly ash and bed ash will be dry and will be collected in two separate ash silos. Fly ash collected by the baghouse will be pneumatically transferred to the fly ash silo (AS1). Air displaced by fly ash silo charging will be controlled by Bin-Vent DC6, while bed ash from the CFB Boiler will be transferred pneumatically to the bed ash silo (AS2) where emissions will be controlled by a bin vent DC7. Bed ash and fly ash will be gravity-fed into trucks through a pug mill where water and ash are mixed to reduce dust generation. Air displaced by ash loading into trucks will be vented through AS1 and AS2 and their associated bin vents DC6 and DC7, respectively. The ash will be transferred from AS1 and AS2 to trucks and disposed of in the on-site ash monofill. In addition to disposal on-site, SME-HGS is researching beneficial uses for the ash.

7. Fuel-Oil Storage Tank

The diesel fuel will be used for CFB Boiler startup, shut-down, and commissioning operations, auxiliary boiler operations, emergency generator operations, and emergency fire pump operations, and will be stored in an above-ground fuel tank. The tank will hold up to 275,000 gallons of #2 diesel fuel. The tank will be limited to the storage of fuels with a vapor pressure of 3.5 kilopascals (kPa) or less to avoid 40 CFR 60, Subpart Kb, applicability.

8. Haul Roads

Trucks will be used for the delivery of limestone and the transport of ash to the monofill. The facility will also have bulldozers and front-end loaders, which will be utilized to maintain the emergency coal storage pile. SME-HGS will use reasonable precautions, including water sprays, to reduce fugitive emissions from unpaved work areas and roadways.

9. CFB Boiler Refractory Brick Curing Heaters

SME-HGS formulated a conservative refractory brick curing scenario (i.e., scenario with conservatively high emission rates). This scenario includes a total heat input to cure the CFB Boiler refractory brick that would not exceed the maximum hourly heat input to the CFB Boiler of 2771 MMBtu/hr. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum of 320 hours of operation per year and shall combust only propane fuel.

C. Current Permit Action

The Department issued its preliminary determination on air quality Permit #3423-00 on March 30, 2006, and accepted comments on the preliminary determination through May 1, 2006. Further, on April 25, 2006, Bison Engineering, Inc., on behalf of SME-HGS, verbally notified the Department of additional emitting units that were not previously analyzed and permitted under the preliminary determination and were deemed necessary for the construction and operation of the CFB Boiler. Specifically, SME-HGS determined that during the CFB Boiler construction phase and periodically thereafter, as necessary, SME-HGS would need to operate portable/temporary propane-fired heaters for the purpose of curing the CFB Boiler refractory brick. SME-HGS submitted an application for the proposed additional emitting units on May 16, 2006, and the Department issued a supplemental preliminary determination on Permit #3423-00 to include the new units. The Department's supplemental preliminary determination was issued as an attachment to the Draft Environmental Impact Statement (DEIS), which was published on June 30, 2006, and was therefore subject to public comment in accordance with the applicable DEIS timeframes. The only changes to the initial preliminary determination under the supplemental preliminary determination were related to the refractory brick curing heaters and administrative errors contained in the initial preliminary determination on Permit #3423-00.

Based on comments received during the public comment period on the Department's initial preliminary determination and additional comments received on the Department's supplemental preliminary determination during the DEIS comment period, the Department's final decision on Permit #3423-00 includes the following changes:

- Modification of the mercury emission control requirements contained in Section II.C.14.b to require installation of activated carbon injection (ACI) control technology, or an equivalent technology (equivalent in removal efficiency), prior to commencement of commercial operations and operation of ACI, or an equivalent technology (equivalent in removal efficiency), after a 6 month IECS operational period.
- Modification of the CFB Boiler Start-Up and Shutdown Plan contained in Attachment 3 to Permit #3423-00.
- Modification of CFB Boiler Start-Up and Shutdown requirements contained in Section II.B.1 to allow for future changes to the *CFB Boiler Start-Up and Shutdown Procedures* contained in Attachment 3, upon written approval of the Department.
- Removal of the Start-Up and Shutdown CO emission limit of 194 lb/hr. The BACT-determined CO emission limit of 0.10 lb/MMBtu contained in Section II.C.8 is applicable during Start-up and Shutdown operations and has been shown, through modeling, to be protective of the National and Montana Ambient Air Quality Standards (NAAQS and MAAQS).
- Modification of Section II.B.3 to include propane as an allowable CFB Boiler start-up and shutdown fuel. The SME-HGS application for air quality permit did not specifically propose propane as an allowable start-up and shutdown fuel for the CFB Boiler. However, based on the analysis of fuel oil, natural gas, and propane provided by SME-HGS for Auxiliary Boiler operations, the Department believes that propane is a relatively clean burning fuel and is therefore a suitable fuel for CFB Boiler start-up and shutdown operations.
- Modification of the language contained in Section II.E.2 to clarify the applicable BACT-determined emission control requirements for the affected material handling transfer points.
- Modification of the source testing schedule for material handling baghouses DC1 through DC5 based on Department source testing schedule guidance using Department-updated uncontrolled emission estimates for the affected units.
- Removal of the term "belt" from the conveyor transfer requirement in Section II.E.5.

- Modification of Section II.F.3 to remove the requirement that all limestone haul trucks be "covered" during transport. The Department determined that the covering of such trucks does not constitute BACT in this case.
- Removal of the language "…for transfer to the on-site ash monofill/landfill" from Section II.G.4, as this language does not constitute an air quality requirement.
- Inclusion of the language "…by manufacturer's design…" to Section II.K.2, because the existing condition contained in the Department's preliminary determination on Permit #3423-00 was not practically enforceable, as written.
- Removal of the language "…or according to another testing/monitoring schedule as may be approved by the Department in writing" from Section II.N.1.a, b, d, and f, as the Department does not have the authority to require a less stringent testing schedule than that required under 40 CFR Part 60.
- Inclusion of the language "…SME-HGS may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained" to Section II.N.1.a, d, f, and j.
- Inclusion of 40 CFR Part 60, Appendix B, Performance Specification #12A, to Section II.P.3.
- Modification of Section III.H, Construction Commencement, to require that construction commence within 18 months of permit issuance.
- Correction of various administrative errors contained in the initial and supplemental preliminary determination(s) on Permit #3423-00.
- Update to the Ambient Impact Analysis contained in Section VI of Permit Analysis to include modeling based on the proposed change in plant footprint to mitigate impacts to the Lewis and Clark historical portage recognized through the EIS process. Modeling is included for both the original and the alternative footprint.
- Removal of all requirements and references to the Acid Rain Program under 40 CFR Parts 72-78. While SME-HGS is subject to the applicable requirements of the Acid Rain Program, the program is implemented under Title V of the Federal Clean Air Act. Therefore, the Department does not have the authority to include Acid Rain Program provisions in Permit #3423-00.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the Administrative Rules of Montana (ARM) and are available, upon request, from the Department. Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. <u>ARM 17.8.101 Definitions</u>. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. <u>ARM 17.8.105 Testing Requirements</u>. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

3. <u>ARM 17.8.106 Source Testing Protocol</u>. (1) The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA). (2) All emission source testing, sampling and data collection,

recording, analysis, and transmittal must be performed as specified in the Montana Source Test Protocol and Procedures Manual, unless alternate equivalent requirements are determined by the Department and the source to be appropriate, and prior written approval has been obtained from the Department. If the use of an alternative test method requires approval by the administrator, that approval must also be obtained.

SME-HGS shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

In the SME-HGS application for Permit #3423-00 and in comments submitted by SME-HGS on the Department's preliminary determination on Permit #3423-00, SME-HGS raised the issue of the accuracy of EPA Method 202 and the need for a refined method to monitor compliance with the permitted CFB Boiler PM_{10} emission limit (filterable and condensable). In those comments, SME-HGS indicated that compliance with the proposed PM_{10} permit limit was tied directly to the use of a refined Method 202 source test. EPA and some states have recognized deficiencies in Method 202 that can produce an inaccurate and unreliable measurement of condensable PM_{10} emissions. EPA currently has an active Work Group studying this issue and intends to provide recommendations to the states on how to deal with the deficiencies in Method 202 and to modify the method to accurately measure emissions, if necessary. In view of the documented potential for problems with Method 202 and SME-HGS' concerns, as expressed in its application and thereafter, the Department has informed SME-HGS that it has authority to approve alternative test methods as part of the source test protocol review process. Approving refinements or alternatives to Method 202 will be considered by the Department through the process outlined in the Montana Source Test Protocol and Procedures Manual.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
6. ARM 17.8.221 Ambient Air Quality Standard for Visibility
7. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

SME-HGS must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne Particulate Matter (PM). (2) Under this rule, SME-HGS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid, or gaseous fuel in excess of the amount set forth in this rule.

6. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). SME-HGS is an NSPS affected facility under 40 CFR Part 60 and is subject to the requirements of the following subparts:

   a. 40 CFR 60, Subpart A. The general provisions provided in 40 CFR 60, Subpart A, apply to all equipment or facilities subject to any Subpart listed below.

   b. 40 CFR 60, Subpart Da. As applicable to CFB Boiler and associated affected equipment.

   c. 40 CFR 60, Subpart Db. As applicable to Auxiliary Boiler and associated affected equipment.

   d. 40 CFR 60, Subpart Y. As applicable to coal processing, handling, and storage equipment and activities.

   e. 40 CFR 60, Subpart OOO. As applicable to limestone processing, handling, and storage equipment and activities.

   f. 40 CFR 60, Subpart HHHH. As applicable under the Montana mercury rules: ARM 17.8.740, ARM 17.8.767, ARM 17.8.771, and ARM 17.8.772.

8. ARM 17.8.341 Emission Standards for Hazardous Air pollutants. This source shall comply with the applicable standards and provisions of 40 CFR 61.

9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

   a. 40 CFR 63, Subpart A. The general provisions provided in 40 CFR 63, Subpart A, apply to all equipment or facilities subject to any Subpart listed below:

b. 40 CFR 63, Subpart B. As applicable facility wide.

c. 40 CFR 63, Subpart ZZZZ. As applicable to the Emergency Generator.

d. 40 CFR 63, Subpart DDDDD. As applicable to the Auxiliary Boiler.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. SME-HGS must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the stacks for the SME-HGS CFB Boiler and Auxiliary Boiler are below the allowable GEP stack height and SME-HGS has demonstrated compliance with all applicable ambient air quality standards as part of the complete permit application for this permit.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. SME-HGS submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. SME-HGS has a PTE greater than 25 tons per year of PM, PM_{10}, NO_x, CO, SO_2, and VOC; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. SME-HGS submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. SME-HGS submitted an affidavit of publication of public notice for the December 7, 2005, issue of the *Great Falls Tribune*, a newspaper of general circulation in the town of Great Falls in Cascade County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving SME-HGS of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.760 Additional Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those applications that require an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

15. ARM 17.8.771 Mercury Emission Standards for Mercury-Emitting Generating Units. This rule specifies applicable mercury emission limitation requirements and initial and subsequent application requirements for the adoption of the appropriate mercury emission limitation(s) and determination of mercury control strategies for mercury-emitting generating units.

16. ARM 17.8.772 Mercury Allowance Allocations under Cap and Trade Budget. This rule describes the Department's responsibilities with respect to mercury allowance allocation and timing of allowance allocations and submittal in conjunction with 40 CFR 60, Subpart HHHH for mercury-emitting generating units.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

This facility is a listed source because it is a fossil-fuel fired steam-electric generating plant having more than 250 MMBtu/hr heat input capacity. Furthermore, the facility's emissions of PM, PM_{10}, NO_X, SO_2, and CO are greater than 100 tons per year; therefore, the facility is a major source under the New Source Review Prevention of Significant Deterioration (PSD) program.

H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

a. PTE > 100 tons/year of any pollutant;

b. PTE > 10 tons/year of any one Hazardous Air Pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

c. PTE > 70 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all major sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #3423-00 for SME-HGS, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for PM, PM_{10}, NO_X, SO_2, and CO.

   b. The facility's PTE is greater than 10 tons/year for a single HAP and greater than 25 tons/year for all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject to NSPS requirements under 40 CFR 60, Subpart(s) A, Da, Db, Y, and OOO.

   e. This facility is subject to NESHAP standards under 40 CFR 63, subpart DDDDD and ZZZZ, as applicable.

   f. This source is a Title IV affected source.

   g. This source is not a solid waste combustion unit.

   h. This source is not an EPA designated Title V source.

   Based on the above information, the SME-HGS facility is a major source of air pollutants as defined under the Title V operating permit program; therefore, a Title V Operating Permit is required. SME-HGS submitted an application for a major source Title V operating permit concurrent with the submittal of the application for Montana Air Quality Permit #3423-00.

III. BACT Determination

A BACT determination is required for each new or modified source of emissions. SME-HGS shall install on the new or modified source of emissions the maximum air pollution control capability that is technically practicable and economically feasible, except that the BACT shall be utilized.

Under the current permit action, SME-HGS proposed a coal-fired power plant incorporating a CFB Boiler for the production of steam to be routed to a steam turbine, which in turn drives an electric generator capable of producing electrical power. The United States Environmental Protection Agency's (EPA) Draft New Source Review Workshop Manual (October 1990) (NSR Manual) states that, "historically, EPA has not considered the BACT requirement a means to re-define the design of the source when considering available control technologies." However, the NSR Manual goes on to indicate "…this is an aspect of the New Source Review – Prevention of Significant Deterioration permitting process in which states have the discretion to engage in a broader analysis if they so desire." Based on the analysis provided below, the Department does not believe that redefining the source is appropriate in this case.

In support of the Department's position on this issue, a recent EPA policy/guidance statement titled *Best Available Control Technology Requirements for Coal-Fired Power Plants*, authored by Stephen D. Page, Director, EPA Office of Air Quality, Planning, and Standards (December 13, 2005), provides that inclusion of technologies such as integrated gasification combined cycle (IGCC) in the BACT analysis for a coal-fired power plant, such as that proposed in this case, constitutes re-

definition of the source and is not appropriate under the BACT analysis and determination process. Since issuance of the Department's preliminary determination and supplemental preliminary determination on Permit #3423-00, EPA has indicated that the policy described in this memo does not constitute a final EPA action on this issue but does constitute the EPA's legal opinion on the issue at this time.

Despite the above-cited reasons for not requiring consideration of other energy production processes, during the research and development phase leading to the proposed SME-HGS project, SME-HGS evaluated various alternative energy technologies including the following: Wind; Solar - Photovoltaic; Solar - Thermal; Hydroelectric; Geothermal; Biomass; Biogas; Municipal Solid Waste; Natural Gas Combined Cycle; Microturbines; Pulverized Coal (PC) Boilers; CFB Boilers; and IGCC. This analysis is compiled in a document created for the U.S. Department of Agriculture, Rural Utility Service (RUS) titled, A*lternative Evaluation Study* (AES). A copy of this document is available for review on the RUS website at www.usda.gov/rus/water/ees/eis.htm and in Appendix D of the SME-HGS application for this air quality permit. This document constitutes a detailed study of alternative energy technologies that were analyzed for future power requirements. The purpose of the AES, as stated in the AES document is "…to determine *an appropriate source of wholesale electric energy and related services post 2008…Provide an analysis of alternatives that SME-HGS has considered to meet its wholesale energy and related supply obligations currently met through the use of power purchase agreements…The alternatives studied by SME-HGS were evaluated in terms of cost effectiveness, technical feasibility, and environmental soundness."*

Additional Evaluation of IGCC and PC Technology

As previously stated, the Department determined that re-defining the proposed CFB coal-fired power project is not appropriate in this case. However, because IGCC and PC technologies represent available and technically feasible electrical power production technologies using coal as fuel, the following information provides additional reasons for rejecting these technologies as BACT for the proposed SME-HGS project based on technical, environmental, and economic factors.

IGCC Power Generation

Based on the analysis included in the SME-HGS application materials and independent Department research, the Department determined that IGCC represents an available and potentially technically feasible strategy for the production of electricity using coal. However, the Department determined that IGCC is technically, economically, and environmentally infeasible for the purpose of meeting the SME-HGS wholesale energy and related supply obligations to its energy cooperative customers.

As provided in the NSR Manual (Section B-19), an analysis of technical feasibility should include an evaluation of the capabilities of the technology for project specific application. At the time of permit issuance, IGCC has not been adequately demonstrated to provide acceptable reliability, with current approaches to improving reliability resulting in less efficient facilities thereby negatively impacting the cost-competitiveness of IGCC for a base-load power generation project. Currently, IGCC incurs an approximate 20% increase in project cost-effective values when compared to CFB power production projects. Therefore, the Department determined that the application of IGCC for the proposed SME-HGS project presents currently un-resolvable reliability concerns leading to unacceptable project cost increases.

Further, based on Department analysis of existing and currently operational similar sized IGCC plant operations, the Department determined that criteria pollutant emissions from IGCC plants, when compared to CFB technology, result in relatively little or no additional environmental protection. The Department understands that the carbon sequestration (greenhouse gas reduction) capabilities of the IGCC technology potentially represent a significant environmental benefit associated with the application of this technology when compared to historically prevalent coal-fired power plant

projects (CFB and PC). However, greenhouse gasses, such as carbon dioxide (CO_2), are not currently regulated under the Montana or federal Clean Air Act. Therefore, because IGCC results in relatively little increased regulated environmental protection, the environmental benefits associated with IGCC greenhouse gas sequestration capabilities do not justify application of this technology for the proposed project.

As summarized above, the Department determined that, at this time, IGCC constitutes a technically, economically, and environmentally infeasible alternative electric power production alternative for the proposed SME-HGS project; therefore, IGCC is eliminated from further consideration under the BACT analysis and determination process.

PC-Boiler Power Generation

Based on the analysis included in the SME-HGS application materials and direct recent and historical Department experience in permitting PC-fired electrical power production projects, the Department determined that PC-fired electrical power production represents an available, technically feasible, and cost-effective strategy for the production of electricity using coal. However, the Department determined that PC-fired electrical power generation does not constitute BACT in this case considering the environmental benefits associated with the proposed CFB coal-fired power project when compared to a PC coal-fired power project.

Operation of a PC-fired boiler in place of the proposed CFB Boiler for the SME-HGS project would result in significantly increased emissions of SO_2, CO, PM_{10}, and total HAPs and relatively similar emissions of NO_x and mercury (specific HAP). Therefore, because SME-HGS proposed a CFB electrical power generation project and the CFB technology would result in less emissions of regulated air pollutants when compared to the PC-fired technology, the Department determined that PC-fired electrical power generation does not constitute BACT in this case.

Project BACT Applicability

The Department determined that the proposed CFB coal-fired power plant represents the most appropriate technology to supply energy to SME-HGS customers taking into consideration technical, environmental, and economic factors. Coal-fired electrical power generation, specifically CFB coal combustion is carried forward into the following BACT analysis and determination process. The following BACT analysis addresses available methods of controlling air pollutant emissions from the following affected equipment:

- CFB Boiler: SO_2, filterable PM, PM_{10} (filterable and condensable), NO_x, CO, VOC, H_2SO_4, acid gasses (HCl and HF), trace metals, radionuclides, and mercury.
- Coal, Limestone, and Ash (Bottom and Fly Ash) Material Processing, Handling, Transfer, and Storage Operations: PM/PM_{10}.
- Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater: PM_{10}, NO_x, CO, SO_2, and VOC.
- Cooling Tower: PM/PM_{10}.
- Haul Roads/Truck Traffic: PM/PM_{10}.
- CFB Boiler Refractory Brick Curing Heaters: PM_{10}, NO_x, CO, SO_2, and VOC.

A. CFB Boiler BACT Analysis and Determination

Startup of a CFB Boiler is a three-phase operation that can take up to 48 hours depending on the initial furnace temperature and conditions of the fluidized bed. During the three-phase startup process, the unit steps through a series of changes to reach full load firing on coal with the addition of limestone into the CFB furnace. During this process, CFB Boiler emissions and emission control strategies may vary until BACT-determined air pollution

control equipment can be operated at a minimum continuous load. A more detailed discussion of start-up and shutdown operations is contained in Attachment 3 to Permit #3423-00.

The Department reviewed the following control options, as well as previous BACT determinations for similar permitted sources in order to make the following pollutant specific BACT determinations.

1. SO_2 Emissions

   Sulfur oxide (SO_x) emissions from fossil fuel combustion consist primarily of SO_2. Additional compounds of SO_x also form at a much lower quantity and consist of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the sulfur in the fossil fuel is oxidized during the combustion process. SME-HGS is proposing to use Powder River Basin (PRB) sub-bituminous coal as the CFB Boiler fuel source and, as such, has analyzed the use of low-sulfur coal for the proposed project.

   Low sulfur coal is typically considered coal with sulfur content at or below 1.0% by weight. Sulfur content and heating content of coal can vary between coal mine and coal seam, which can impact SO_2 emissions from the source. High sulfur coal is typically between 1% and 5% sulfur by weight. Coal analyzed for the proposed project will typically have sulfur content less than 0.8% by weight and heating values greater than 8,600 Btu/lb.

   A. Identification of Available SO_2 Control Strategies/Technologies

      Several techniques can be used to reduce SO_2 emissions from CFB Boiler fossil fuel combustion. SO_2 control options can be divided into pre-combustion strategies (e.g., combusting low sulfur fuels, fuel blending, coal cleaning, etc.), combustion techniques, and post-combustion controls typically characterized as flue gas de-sulfurization (FGD) units (e.g., wet scrubbers, dry scrubbers, etc.). The following available SO_2 control options/technologies/strategies were evaluated for the proposed project:

      i. CFB Boiler with High-Sulfur Coal
      ii. CFB Boiler with Low-Sulfur Coal (Fuel Blending or Switching)
      iii. CFB Boiler with Limestone Injection
      iv. CFB Boiler with Coal Cleaning
      v. CFB Boiler with FGD
         a. Wet Lime Scrubber/Wet Limestone Scrubber
         b. Dual Alkali Wet Scrubber
         c. Spray Dry Absorber
         d. Dry-Sorbent Injection
         e. Circulating Dry Scrubber
         f. Hydrated Ash Re-injection (HAR)
      vi. CFB Boiler with Low-Sulfur Coal and Coal Cleaning
      vii. CFB Boiler with Low-Sulfur Coal and FGD
      viii. CFB Boiler with Low-Sulfur Coal and Limestone Injection
      ix. CFB Boiler with High or Low-Sulfur Coal, Coal Cleaning, and FGD
      x. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and Coal Cleaning
      xi. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and FGD
      xii. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, Coal Cleaning, and FGD

The following text provides a brief overview of the above-cited SO_2 control options/technologies/strategies that have been evaluated for the proposed project.

i. CFB Boiler with High-Sulfur Coal

SO_2 emissions from a CFB Boiler with no add-on control are strictly dependent on the sulfur content of the coal being fired. The coal for a CFB Boiler is crushed to a specific size and injected into the CFB Boiler. The coal mixes with the bed material and circulates through the boiler until all of the coal is combusted. The bed material can be made up of stone, sand, and/or limestone. The use of limestone as a bed material is a common industry practice as a first stage SO_2 control strategy.

ii. CFB Boiler with Low-Sulfur Coal (Fuel Blending or Switching)

Another potential control option for reducing SO_2 emissions is to reduce the amount of sulfur contained in the coal by using low-sulfur coal (e.g., current project proposal) or by blending low-sulfur coal with relatively higher sulfur coal (e.g., Midwestern United States bituminous coal). Low-sulfur coal is used as a means to decrease the SO_2 emissions without installing SO_2 add-on control devices. By blending low sulfur coal with high sulfur coal or by switching from high sulfur coal to a lower sulfur coal, SO_2 emissions will decrease. When low-sulfur coal is readily available, fuel blending or switching can be a cost-effective means to reduce SO_2 emissions. CFB Boilers are typically not sensitive (from an operational standpoint) to different types of coal or solid fuels. This is one of the benefits of a CFB Boiler.

iii. CFB Boiler with Limestone Injection

In a CFB Boiler, crushed limestone ($CaCO_3$) is fed to the combustor and becomes part of the solid medium that makes up the combustion bed. Within the combustion zone, lime (CaO) is formed by calcining the $CaCO_3$. SO_2 formed during the combustion process combines with the calcined CaO to form gypsum ($CaSO_4$), a stable byproduct, or $CaSO_3$ as shown in the following reactions:

$$SO_2 + CaO + \tfrac{1}{2}O_2 \rightarrow CaSO_4$$

or

$$SO_2 + CaO \rightarrow CaSO_3$$

The SO_2 removal equation shows that one mole of calcium is required to capture one mole of sulfur. Therefore, the theoretical minimum Ca/S ratio required for the removal of a given sulfur concentration is 1/1, assuming 100% utilization of the sorbent. However, the actual removal efficiency that can be achieved in practice for a given unit is dependent on several factors including the size and porosity of the lime, temperature of the combustion bed, residence time within the combustion bed, mixing, and uncontrolled SO_2 concentration. In practice, it has been found that approximately 50% of the SO_2 will be removed at a Ca/S ratio of 1. As the Ca/S ratio increases, a greater amount of SO_2 will be removed, but with diminishing return. Limestone injection is an integral part of the CFB Boiler process; however, the actual limestone injection rate varies from unit to unit as the sulfur in the coal or fuel varies.

iv. CFB Boiler with Coal Cleaning

Various coal cleaning processes may be employed to reduce the coal sulfur content. Physical coal cleaning removes mineral sulfur (such as pyrite) but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur. Coal cleaning has generally been used on high mineral, high sulfur, coal for power plants without FGD systems with some success. In some studies, coal-cleaning processes have been noted to reduce the feed coal sulfur content by 1% in high sulfur coal with sulfur contents up to 5%. This equates to an approximate 20% reduction in total sulfur-in-coal. Coal cleaning requires water and/or chemicals for removing the sulfur, pyrite, and other materials; consequently, a wastewater stream is produced by the coal cleaning system, which must be treated before discharge from the facility.

v. CFB Boiler with FGD

Post-combustion methods for CFB Boilers mainly consist of FGD and are typically classified as either wet or dry systems. Wet and dry FGD are well-established SO_2 control options. Wet FGD removes SO_2 with a wet lime or limestone slurry as compared to dry FGD, which injects dry lime or limestone and produces a dry by-product that is removed with the fly ash in the particulate control device (e.g., fabric filter baghouse (FFB)). Dry FGD, as the name applies, does not use water and does not require a wastewater disposal system. The following text provides a brief overview of available FGD systems:

a. Wet Lime/Limestone Scrubber

The wet lime scrubbing process uses alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed into the exhaust stream and reacts with the SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product. The waste by-product is mainly $CaSO_3$, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills.

Wet limestone scrubbers are very similar to wet lime scrubbers. However, the use of limestone ($CaCO_3$) instead of CaO requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The $CaCO_3$ slurry process also requires a ball mill to crush the $CaCO_3$ feed.

Forced oxidation of the scrubber slurry can be used with either the lime or limestone wet FGD system to produce gypsum solids instead of calcium sulfite by-product. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the FGD. The gypsum by-product may be sold for other uses, reducing the quantity of solid waste that needs to be disposed of in a landfill.

Wet lime/limestone scrubbers can achieve SO_2 control efficiencies of approximately 95% or greater when used on boilers burning higher sulfur bituminous coals, but may be less efficient when the boiler is combusting

lower sulfur coals, such as that proposed for the current project. The actual control efficiency of a wet lime/limestone FGD system depends on several factors, including the uncontrolled SO_2 concentration entering the scrubber.

b. Dual Alkali Wet Scrubber

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop. The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary.

A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonate, and sodium sulfite, is an efficient SO_2 control reagent. However, the high cost of the sodium-based chemicals may limit feasibility of such an installation on a generating unit size of 100 MW or larger utility boiler. In addition, the process generates a less stable sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater. As with the wet lime/limestone scrubbers, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

c. Spray Dryer Absorber (SDA)

The typical SDA uses lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device, and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use. SDAs are a commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 95% SO_2 reduction. Again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

d. Dry Sorbent Injection

Dry sorbent injection involves the injection of powdered or hydrated sorbent (typically alkaline) directly into the flue gas exhaust stream. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. The dry sorbent is typically injected countercurrent to the gas flow through a Venturi orifice. An expansion chamber is often

located downstream of the injection point to increase residence time and contact efficiency. Particulates generated in the reaction are controlled in the system's particulate control device. SO_2 control efficiencies for dry sorbent injection systems are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers. Once again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

e. Circulating Dry Scrubber

A third type of dry scrubbing system, the circulating dry scrubber (CDS), uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a Venturi orifice at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the unit's particulate removal system.

f. Hydrated Ash Re-Injection (HAR) System.

The HAR process is a modified dry FGD process developed to increase utilization of un-reacted lime (CaO) in the CFB ash and any free CaO left from the furnace burning process. The hydrated ash re-injection process will further reduce the SO_2 concentration in the flue gas. The actual design of a HAR system is vendor-specific and hydrated ash re-injection type systems may be referred to as a Flash Dry Absorber™ (Alstom trade name) or a polishing scrubber.

In a hydrated ash re-injection system, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFB applications, sufficient residual CaO is available in the ash and additional lime is not required. It is estimated that potential SO_2 emissions would be reduced by approximately 90 to 95% in the CFB with an additional 60 to 80% reduction achieved with the addition of a HAR system. The overall control efficiency would be approximately 97% to 98% with low sulfur coal and even greater with high sulfur coal fuel.

vi. CFB Boiler with Low-Sulfur Coal and Coal Cleaning

As stated previously, coal cleaning is typically performed on high-sulfur coals. The economics of cleaning low-sulfur coal show this to be an expensive method with relatively little benefit of additional reduction in sulfur.

vii. CFB Boiler with Low-Sulfur Coal and FGD

Low-sulfur coal is typically used to reduce overall SO_2 emissions from a CFB Boiler. However, the control efficiency decreases as the inlet SO_2 decreases with a lower-sulfur coal.

viii. CFB Boiler with Low-Sulfur Coal and Limestone Injection

As stated previously, limestone can be injected in the CFB Boiler as bed material, which can help reduce SO_2 emissions. Low sulfur coal would not require as much limestone injection as a high sulfur coal to achieve an equivalent SO_2 emission rate.

ix. CFB Boiler with High or Low-Sulfur Coal, Coal Cleaning, and FGD

As stated previously, coal cleaning can remove approximately 20% of the boiler SO_2 emissions. Coal cleaning is typically applied to high-sulfur coals on systems without FGD. When FGD systems are installed, coal cleaning is typically not justified due to limited additional SO_2 reduction realized for a relatively high cost.

x. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and Coal Cleaning

As stated previously, coal cleaning is typically performed on high sulfur coals with no additional SO_2 control. The cost of cleaning coal prior to a CFB with limestone injection is expensive with relatively little benefit of reduction in SO_2 emissions through the reduction of sulfur-in-coal.

xi. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and FGD

FGD systems can be added as a "polishing" scrubber on a CFB Boiler with limestone injection. This control option typically can remove SO_2 emissions at a control efficiency greater than 97% with low-sulfur coal and can achieve higher control efficiency with a high sulfur coal. The CFB Boiler technology with low sulfur coal, limestone injection, and HAR FGD SO_2 control strategy has been proposed by SME-HGS for the project.

xii. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, Coal Cleaning, and FGD

As stated previously, coal cleaning is typically performed on high sulfur coals for use in boilers with no additional SO_2 control. The economics of cleaning coal prior to a CFB with limestone injection and FGD is expensive with very little benefit of reduction in sulfur.

B. Technical Feasibility Analysis

SME-HGS is proposing to use low sulfur coal with an average sulfur content of approximately 0.7% sulfur by weight. Therefore, although high sulfur coal is technically feasible, all control options for high sulfur coal are eliminated from further evaluation. Since coal cleaning is typically performed on high sulfur coals, and provides minimal additional benefit when performed on low sulfur coal, all control options with coal cleaning are eliminated from further evaluation.

The circulating dry scrubber has limited application, and has not been used on large CFB Boilers. Furthermore, circulating dry scrubber systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, electrostatic precipitators (ESP) are generally used for particulate control. For reasons further discussed in the filterable PM (filterable and condensable) BACT analysis for the CFB Boiler, the Department determined that FFB constitutes BACT for CFB

Boiler particulate control. Based on limited technical data from non-comparable applications and engineering judgment, the Department determined that CDS is not technically feasible with a CFB Boiler equipped with FFB particulate control. Therefore, the CDS will not be evaluated further.

Although a dry sorbent injection system may be technically feasible, it is not practical for use with a CFB. The CFB flue gas contains excess un-reacted lime and heavy ash particles that will be re-injected back into the CFB combustion bed. A dry sorbent injection system would simply add additional unreacted lime to the flue gas. Furthermore, SO_2 control efficiencies for dry sorbent injection systems are typically around 50% on units with a much higher uncontrolled SO_2 concentration in the flue gas. If used in conjunction with a CFB unit (with a relatively low SO_2 concentration in the flue gas), the control efficiency would be expected to be something less than 50%. Because the dry sorbent injection system is not practical with a CFB, and because the control efficiency of the dry sorbent system is lower than the control efficiency of other post-combustion control options, the system will not be evaluated further.

Summary Table: SO_2 Control Option Infeasibility	
SO_2 Control Option	**Basis for Infeasibility**
All Control Options with High Sulfur Fuel	SME-HGS is proposing to use low sulfur coal.
All Control Options with Low Sulfur Fuel and Coal Cleaning	Coal cleaning is considered ineffective with low sulfur coal because it is mostly organic sulfur and does not react to cleaning as well as the higher sulfur content bituminous coals.
CFB with or without Limestone Injection with Low Sulfur Coal and Dry Sorbent Injection	Not as effective an SO_2 option as dual-alkali, SDA, or hydrated ash re-injection. Eliminated from further evaluation.
CFB with or without Limestone Injection with Low Sulfur Coal and Circulating Dry Scrubber	Limited actual experience and not considered technically feasible because of the high particulate loading and excess pressure drop across a FFB.

C. Ranking of Available and Technically Feasible SO_2 Control Options by Efficiency

Wet scrubbing systems (without additional control options) are capable of removing approximately 90-95% of SO_2 emissions from higher sulfur coals. Though various reagents such as lime, limestone, or magnesium-enhanced lime all have different SO_2 removal efficiencies, overall system efficiency is maintained by operating with a slurry feed rate that is appropriate for the reagent being used. For the present analysis, the wet FGD system will be evaluated with an upstream fabric filter baghouse (FFB) followed by a wet lime scrubber. Particulate control is required upstream from the scrubber to maintain scrubber efficiency.

Dry FGD systems are reported to be capable of removing up to 95% of the SO_2 in flue gas streams resulting from combustion of high-sulfur coal. These systems must include downstream particulate control equipment since the FGD adds particulate to the gas stream. FFBs and electrostatic precipitators (ESPs) provide essentially equivalent particulate control efficiency. The dry FGD system will be evaluated with an FFB since it potentially enhances SO_2 and sulfuric acid mist (H_2SO_4) removal efficiency, which does not occur with an ESP. As the exhaust gas passes through a filter cake containing alkaline ash and un-reacted reagent, additional SO_2 is removed. For this reason, the system configuration of a dry FGD in combination with an ESP will not be further evaluated for the proposed project.

The combination of a CFB Boiler with limestone injection and an FGD can have an overall SO_2 control efficiency of approximately 97% to 98%. This level of collection efficiency is achieved due to the reaction time allowed for the lime in both the CFB furnace as well as the FGD.

Summary Table: SO_2 Control Option Rank by Efficiency		
SO_2 Control Option	**Emission Rate (lb/MMBtu)[a]**	**SO_2 Control Efficiency**
CFB with Limestone Injection, Low Sulfur Coal, and Wet Lime/Limestone Scrubber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Dual-Alkali Wet Scrubber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Spray Dry Absorber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Hydrated Ash Reinjection	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal (Fuel Blending or Switching)	0.08	94.4%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Wet Lime Scrubber	0.10	93%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Wet Limestone Scrubber	0.10	93%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Dual-Alkali Wet Scrubber	0.16	88.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Spray Dry Absorber	0.16	88.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Dry Sorbent Injection	0.80	43.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal (without control)	1.42	---
[a] Based on a 30-day rolling average		

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following paragraphs evaluate environmental, economic, and energy impacts associated with the remaining SO_2 control options on a CFB Boiler with limestone injection. All control options/strategies without limestone injection have been eliminated from further BACT consideration because SME-HGS proposed limestone injection technology and because a CFB Boiler with limestone injection represents greater SO_2 control efficiency when compared to CFB without limestone injection.

i. Environmental Impacts

Wet FGD systems emit some level of mist that poses negative environmental impacts related to acid gas emissions (H_2SO_4, HCl, and HF), fine particulate emissions, and near and far-range visibility degradation. Dry FGD systems avoid these problems because the technology does not produce mist and because emissions from the absorber must pass through a filter cake of alkaline material collected in the downstream FFB before exhausting to the

atmosphere. Another negative environmental impact associated with a wet FGD system is related to water usage. A wet FGD system uses approximately 20% more water than a dry FGD.

Both wet and dry systems produce solid waste streams containing fly ash and spent lime or limestone and these wastes are generally disposed of in a landfill area or stored in surface impoundments. The wet dual-alkali system uses sodium-based chemicals, which generates a less stable sludge than wet lime/limestone scrubber sludge. This can create material handling and disposal issues of concern.

Even though wet FGD systems use more water and generate a wastewater sludge, wet FGD systems cannot be eliminated from further investigation under the BACT analysis and are therefore evaluated further for economic and energy impacts. The dual-alkali wet scrubber will be eliminated from further investigation due to the material handling and disposal issues (e.g., leachate polluting the ground water causing long-term storage issues) associated with the sludge byproducts.

ii. Economic Impacts

Department verified economic impacts associated with CFB Boilers for each of the above FGD systems were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates were provided from commercial suppliers of this type of equipment. Where appropriate, constant operation and maintenance factors were identified and applied consistently to control options. As reported in the application, the cost effective value for CFB with limestone injection, low-sulfur coal, and wet lime/limestone scrubber is approximately \$27,365/ton SO_2 removed; the cost effective value for CFB with limestone injection, low sulfur coal, and SDA is approximately \$7939/ton SO_2 removed; and the cost effective value for CFB with limestone injection, low sulfur coal, and HAR is approximately \$4,054/ton SO_2 removed. Based on the cost-effective values provided above, CFB with limestone injection, low sulfur coal, and HAR is deemed economically feasible for the affected unit and all other control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

iii. Energy Impacts

Both wet and dry FGD systems require electricity to operate. The wet FGD system uses electricity primarily for the ID fan, re-circulation pumps, reagent handling, and for wet waste dewatering. The dry FGD uses electricity primarily for the ID fan, lime/limestone handling equipment and FFB blowers. Wet FGD system power consumption is approximately 40% greater than that of the dry FGD system. With a HAR system, there is no recirculation pump, wet waste dewatering and reduced power consumption for the reagent (lime/limestone) handling system. None of the control options are eliminated based on energy impacts.

E. SO_2 BACT Determination

SME-HGS proposed the use of CFB Boiler technology with limestone injection, low sulfur coal, and HAR to maintain compliance with a proposed SO_2 BACT emission limit of 0.038 lb/MMBtu (30-day average). Based on Department verified information contained in the SME-HGS application for Permit #3423-00 and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed SO_2 emission control strategy and emission limit constitute BACT in this case. This BACT determined control option constitutes an approximate 97% SO_2 reduction efficiency.

Other recent SO_2 BACT determinations for coal-fired power plants were researched in the RACT/BACT/LAER Clearinghouse (RBLC) and Western US agency websites. The Department verified data from these websites is summarized in the application. The SME-HGS BACT determined SO_2 emission limit is at the low end of all other recently permitted similar source SO_2 BACT determinations, world-wide. The only facilities with permitted and BACT determined SO_2 emission limits lower than SME-HGS are the AES facility in Puerto Rico and the proposed NEVCO facility in Utah. The applicable SO_2 BACT emission limit for both of these facilities is 0.022 lb/MMBtu. To the best of the Department's knowledge, as of the date of permit issuance, compliance with the applicable SO_2 BACT emission limit had not been demonstrated at the AES facility or the NEVCO facility.

The Department determined that the CFB Boiler operating under the BACT determined control requirements is capable of meeting the established SO_2 BACT emission limit of 0.038 lb SO_2/MMBtu (30-day average). Further, the Department determined that the periodic SO_2 source testing, the applicable continuous emission monitoring requirements, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted SO_2 BACT limit(s).

2. Filterable PM Emissions

Particulate matter emissions consist of filterable and condensable particulate. Filterable PM resulting from the proposed SME-HGS project is comprised of ash from the combustion of fuel, noncombustible metals present in the fuel, and unburned carbon resulting from incomplete combustion. Filterable PM is material that is in particulate form within the boiler stack and thus collects on the filter of a particulate sampling train. Condensable particulates include condensable organic compounds and minerals (in vapor form) that pass through the filter on a sampling train and are collected in glass impingers that contain a chilled wet solution to condense the vapors from the exhaust stream.

This BACT analysis focuses on control technologies for filterable PM. PM_{10} (filterable and condensable) is addressed later in the BACT analysis for the proposed project (see PM_{10} (filterable and condensable) BACT Analysis and Determination).

A. Identification of Available Filterable PM Control Strategies/Technologies

Several techniques can be used to reduce filterable PM emissions from fossil fuel combustion. Three of the most commonly available and effective methods for control of filterable PM emissions are listed below:

i. Wet scrubbers,
ii. Electrostatic precipitators (ESP), and
iii. Fabric filter baghouses (FFB)

The above-cited control strategies and/or combinations thereof, as detailed in the following table, can be used to effectively control filterable PM/PM_{10}.

Summary Table: Available Filterable PM Control Options		
Emitting Unit	**Control Option**	**Combined Control Option**
CFB Boiler	Wet or Dry ESP	Wet Scrubber with Wet ESP
	FFB with Fiberglass Bags	
	FFB with Specialty Bags	Wet Scrubber with FFB
	Wet/Dry Scrubber	

A general description of the ESP, FFB, and wet scrubber control technologies is described below. Only the control device is described, not each control option listed above.

i. Wet Scrubbers

Wet scrubbers typically use water to impact, intercept, or diffuse a particulate-laden gas stream. With impaction, particulate matter is accelerated and impacted onto a surface area or into a liquid droplet through devices such as a venturi or spray chamber. When using interception, particles flow nearly parallel to the water droplets, which allows the water to intercept the particles. Interception works best for submicron particles. Spray-augmented scrubbers and high-energy venturi employ this mechanism. Diffusion is used for particles smaller than 0.5 micron and where there is a high temperature difference between the gas and the scrubbing liquid. The particles migrate through the spray along lines of irregular gas density and turbulence, contacting droplets of approximately equal energy.

Six particulate scrubber designs are used in wet scrubber control applications: spray, wet dynamic, cyclonic spray, impactor, Venturi, and augmented. In all of these scrubbers, impaction is the main collection mechanism for particles larger than 3 microns. Since smaller sized particles respond to non-inertial capture, a high density of small liquid droplets is needed to trap the particles. This is done at the price of high-energy consumption due to hydraulic or velocity pressure losses (William Vatavuk, *Estimating Costs of Air Pollution Control*, 1990). Wet scrubbers used specifically for particulate control are not commonly used on large utility boilers because of the high pressure drop to remove particulate to levels equivalent to those achieved with an FFB or ESP. Wet scrubbers are commonly designed for SO_2 removal instead of particulate control.

ii. ESP

An ESP is a particulate control device that uses electric forces to move particles out of the gas stream and onto collector plates. The particles are given an electric charge by forcing them to pass through the corona that surrounds a highly charged electrode, frequently a wire. The electrical field then forces the charged particles to the opposite charged electrode, usually a plate. Solid particles are removed from the collection electrode by a shaking process know as “rapping.” ESPs may be configured in several ways including the plate wire precipitator, the flat plate precipitator, the tubular precipitator, the wet precipitator, and the two-stage precipitator. These descriptions are outlined in the EPA *OAQPS Cost Control Manual* for ESP control.

The plate wire precipitator is the most common variety. It is commonly installed on coal fired boilers, cement kilns, solid waste incinerators, paper mill recovery boilers, petroleum refining catalytic cracking units, sinter plants, and different varieties of furnaces. Plate wire precipitators are designed to handle large volumes of gas. The flat plate precipitator is designed to use flat plates instead of wires for high-voltage electrodes. Small particle sizes with low-flow velocities are ideal for the flat plate precipitator. The flat plate precipitator usually handles gas flows ranging from 100,000 to 200,000 actual cubic feet per minute (acfm). Tubular precipitators are typically parallel tubes with electrodes running along the axis of the tubes. Tubular precipitators have typical applications in sulfuric acid plants, coke oven byproduct gas cleaning, and steel sinter plants. Wet precipitators can be any of the three previously discussed precipitators but with wet collection plates instead of dry collection plates. A wet precipitator aids in further collection of particles by preventing the collected ash from being re-entrained in the exhaust stream during the rapping of the walls, a problem common to dry precipitators. The disadvantages are the complexity of handling the wash and disposal of the slurry.

Finally, two-stage precipitators are parallel in nature (i.e., the discharge and collecting electrodes are side by side). Two-stage precipitators are designed for indoor applications, low gas flows below 50,000 acfm, and sources emitting submicrometer particulate such as oil mists, smokes, fumes, and other sticky particulates. Two-stage systems are specialized types of devices that are very limited in applications.

Dry ESPs may be used downstream of a dry FGD unit to collect the dry FGD media and the ash formed during fuel combustion. However, they do not enhance SO_2 or SO_3 control. Dry ESPs are not suited for use downstream of wet FGD systems due to the high moisture content of the gas stream and the resulting stickiness of the particles. Wet ESPs may be used downstream of a wet FGD unit to capture both residual flue gas particulate and H_2SO_4 that may have formed in the wet FGD unit.

iii. FFB

FFBs consist of one or more isolated compartments containing rows of fabric filter bags or tubes. The exhaust stream passes through the fabric where the filterable particulate is retained on the upstream face of the bags, while the cleaned gas stream is vented to the atmosphere or to another pollution control device. FFBs collect particle sizes ranging from submicron to several hundred microns at gas temperatures up to approximately 500°F. Specialty bags can be used to achieve lower particulate emission rates or with stack temperatures above 500°F. FFBs can be categorized by the types of cleaning devices (shaker, reverse-air, and pulse-jet), direction of the gas flow, location of the system fan, and/or the gas flow quantity. Typically, the type of cleaning method distinguishes the FFB.

Advantages to FFBs are the high collection efficiency (in excess of 99%) and the collection of a wide range of particle sizes. The operational disadvantages of FFBs are limits on gas stream temperatures above 500°F (for typical installations), high-pressure drops, wet gas streams, and issues resulting from gas or particles that are corrosive and/or sticky in nature.

FFBs are not used downstream of a wet FGD system due to the high moisture content of the exhaust gas, which will saturate and ultimately plug the fabric filters. When used downstream of a dry FGD system, the FFB provides additional sulfur oxide control. The alkaline filter cake continues to react with and remove gaseous SO_2 and SO_3 as they pass through the filters. The alkaline filter cake also captures acid gas mist that may have formed in the exhaust system.

B. Technical Feasibility Analysis

Wet scrubbers designed for particulate control are technically infeasible on large utility boilers because of the high-pressure drops. FFB and ESP particulate control devices are commonly used on large utility boilers and are examined further for BACT applicability.

C. Ranking of Available and Technically Feasible Filterable PM/PM_{10} Control Options by Efficiency

FFBs and ESPs have proven capabilities in removing greater than 99% of the filterable PM from the exhaust gas stream generated by processes similar to the SME-HGS CFB Boiler. FFBs are generally specified for use downstream of a dry FGD system. The following table ranks the filterable PM control efficiency for the specified control options.

Summary Table: Filterable PM Control Option Rank by Efficiency		
Filterable PM/PM_{10} Technology	**Emission Rate (lb/MMBtu)**	**Estimated Control Efficiency**
CFB with FFB with Teflon-Coated Bags	0.012	99.85%
CFB with FFB with Fiberglass Bags	0.015	99.81%
CFB with ESP	0.018	99.77%
CFB with No Add-on Control	7.78	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following paragraphs evaluate environmental, economic, and energy impacts associated with the Filterable PM control options on a CFB Boiler with limestone injection.

i. Environmental Impacts

The predominant environmental impact from controlling particulate in an FFB or ESP is related to the fly ash that is collected. The fly ash needs to be properly handled and deposited. SME-HGS is proposing to dispose of the fly ash and bed ash in an on-site monofill. Further, an ESP does not provide the additional co-benefit SO_2/SO_3 collection due to the alkaline filter cake on the bags, but has not been eliminated based on environmental impacts.

ii. Economic Impacts

Department verified economic impacts associated with filterable particulate control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Where appropriate,

constant operation and maintenance factors were identified and applied consistently to control scenarios. Department verified and detailed information regarding economic impacts is contained in the application for this air quality permit.

The annual operating cost for Teflon-coated bags is approximately $500,000 more than the operating cost for standard fiberglass bags. The increase in annual cost is mainly associated with more expensive bags, and a smaller portion of the annual cost increase is associated with additional operating and maintenance costs. Despite the increase in costs associated with the use of Teflon-coated bags, the Department determined that an emission limit of 0.012 lb/MMBtu represents an achievable and cost-effective limit. As reported in the application, the annual cost-effective value for Teflon-coated bags for the proposed project is approximately $83/ton filterable PM removed as compared to approximately $78/ton filterable PM removed using standard fiberglass bags. Based on the cost-effective values provided above, all control options are deemed economically feasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

iii. Energy Impacts

Each of the control options require power in the form of fan horsepower to overcome the control device pressure drop. However, energy impacts do not eliminate any of the control options.

E. Filterable PM BACT Determination

SME-HGS proposed the use of FFB to maintain compliance with a proposed filterable PM BACT emission limit of 0.015 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed FFB PM control strategy constitutes BACT in this case. However, the Department determined that the proposed emission limit of 0.015 lb/MMBtu does not constitute BACT in this case.

The FFB provides better particulate control than an ESP, is widely used in the coal-fired power generation industry, and was analyzed and is required as part of the SO_2 BACT control determination. An FFB on a CFB with limestone injection and HAR provides a co-benefit of SO_2/SO_3 control, whereas an ESP does not provide this co-benefit control.

The Department determined that maintaining compliance with a limit of 0.012 lb/MMBtu constitutes BACT in this case. In the BACT analysis contained in the application, SME-HGS states that discussions with baghouse manufacturers and vendors indicate a limit of 0.012 lb/MMBtu will not be guaranteed without significant increases in costs in order to cover any risks associated with performance guarantees and liquidated damages. However, the Department determined that the cost-effective values incurred by SME-HGS in order to meet a filterable PM emission limit of 0.012 lb/MMBtu are well within industry norms and constitute BACT in this case. Further, the Department determined that the BACT-determined FFB is capable of reducing visible emissions from the CFB Boiler stack to a level that will not exceed 20% opacity averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity. The Department determined that these opacity limits constitute BACT for visible emissions in this case.

Further, the BACT determined filterable PM emission limit and opacity limits are consistent with the values reported in the RBLC for other recently permitted and similar sources, including recently permitted sources permitted and operating in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT determined control requirements is capable of meeting the established filterable PM BACT emission limit of 0.012 lb/MMBtu and 33.25 lb/hr (0.012 lb/MMBtu * 2770.6 MMBtu/hr average boiler heat input capacity) and the visible emissions standard of less than 20% opacity averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity. Further, the Department determined that the periodic filterable PM source testing, continuous opacity monitoring, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted filterable PM and opacity BACT limit(s).

3. NO_x Emissions

NO_x is formed by thermal oxidation of nitrogen in the combustion air and by oxidation of nitrogen in the fuel. Thermal NO_x is formed in the high temperature region of the flame or combustion zone of the affected combustion unit. The major factors influencing thermal NO_x formation are temperature, residence time within the combustion zone, and concentration of nitrogen and oxygen in the inlet air. The amount of fuel NO_x formed is wholly dependent on the amount of nitrogen compounds contained in the fuel.

A. Identification of Available NO_x Control Strategies/Technologies

Applicable NO_x control technologies can be divided into two main categories: combustion controls, which limit NO_x production, and post-combustion controls, which destroy NO_x after formation.

The following specific add-on technologies were identified as having the potential to reduce NO_x emissions from a CFB Boiler:

Emitting Unit	**Individual Control Options**	**Dual Combined Control Options**
CFB Boiler	Low Excess Air (LEA)	Combination of LEA, FGR, OFA, and LNB
	Flue Gas Recirculation (FGR)	
	Overfire Air (OFA)	Combination of LEA, FGR, OFA, and/or LNB and SCR
	Low NOx Burners (LNB)	
	Selective Catalytic Reduction (SCR)	Combination of LEA, FGR OFA, and/or LNB and SNCR
	Selective Non-Catalytic Reduction (SNCR)	

A general description of the NO_x control options listed in the table above is described in the following text. Only the control device/strategy is described, not each control option listed above.

i. Low Excess Air (LEA)

LEA operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of fuel NO_x and lowers the peak flame temperature, which inhibits thermal NO_x formation.

Emissions reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of CO, hydrocarbons and unburned carbon increase, resulting in lower boiler efficiency. Other impediments to LEA operation are the possibility of increased corrosion and slagging in the upper boiler because of the reducing atmosphere created at low oxygen levels. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

ii. Flue Gas Recirculation (FGR)

FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. FGR also serves to reduce the O_2 concentration in the combustion zone. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

iii. Overfire Air (OFA)

OFA allows staged combustion by supplying less than the stoichiometric amount of air theoretically required for complete combustion through the burners. The remaining necessary combustion air is injected into the furnace through overfire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of fuel NO_x. In this atmosphere, most of the fuel nitrogen compounds are driven into the gas phase. Combustion occurring over a larger portion of the furnace lowers peak flame temperatures. Use of a cooler, less intense flame limits thermal NO_x formation.
Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash. These products of incomplete combustion result from a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion of the boiler. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

iv. Low NO_x Burners (LNB)

LNB integrate staged combustion into the burner creating a fuel-rich primary combustion zone. Fuel NO_x formation is decreased by the reducing conditions in the primary combustion zone. Thermal NO_x is limited due to the lower flame temperature caused by the lower oxygen concentration. The secondary combustion zone is a fuel lean zone where combustion is completed. LNB may result in increased CO and hydrocarbon emissions, decreased boiler efficiency, and increased fuel costs. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

v. Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique that uses a catalyst to reduce NO and NO_2 to molecular nitrogen and water. Ammonia (NH_3) is commonly used as the reducing agent. The basic reactions are:

$$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$8\ NH_3 + 6\ NO_2 \rightarrow 7\ N_2 + 12\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Ammonia is vaporized and injected into the flue gas upstream of the catalyst bed, and combines with NO_x at the catalyst surface to form an ammonium salt intermediate. The ammonium salt intermediate then decomposes to produce elemental nitrogen and water. The catalyst lowers the temperature required for the chemical reaction between NO_x and ammonia.

Technical factors that impact the effectiveness of this technology include the catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, and the potential for catalyst poisoning. SCR has been demonstrated to achieve high levels of NO_X reduction in the range of 80% to 90% control for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines. SCR has not been demonstrated on a CFB Boiler in the United States. Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). However, calcium oxide (from a dry scrubber) in the exhaust stream can cause the SCR catalyst to plug and foul, which would lead to an ineffective catalyst. SCRs are classified as a low or high dust SCR. A low dust SCR is usually applied to natural gas combustion units or after a particulate control device. High dust SCR units can be installed on solid fuel combustion units before the particulate control device. However, a high dust SCR cannot be installed on a CFB Boiler prior to the particulate control device because the high alkaline particulate will contaminate and possibly plug the catalyst. Therefore, the exhaust stream after a particulate control device on a CFB Boiler would need to be reheated to maintain an effective operating temperature of the catalyst.

vi. Selective Non-Catalytic Reduction (SNCR)

SNCR involves the non-catalytic decomposition of NO_x to nitrogen and water. A NO_x reducing agent, typically ammonia or urea, is injected into the upper reaches of the furnace. Because a catalyst is not used to drive the reaction, temperatures of 1600°F to 2100°F are required. The basic reactions are:

Ammonia: $4\ NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$
Urea: $CO(NH_2)_2 + 2NO + ½O_2 \rightarrow 2N_2 + CO_2 + H_2O$

Typical NO_x control efficiencies range from 40% to 60% depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and presence of interfering chemical substances in the gas stream. SNCR has been applied to a number of different types of combustion sources. SNCR has been widely implemented for NO_x control on new coal-fired CFBs throughout the United States.

B. Technical Feasibility Analysis

LNB, OFA, LEA, and FGR are used to reduce flame temperature and reduce the thermal NO_x; therefore, these control options separately or in combination with another control option, including SCR and SNCR, are technically ineffective on a CFB Boiler that has inherently low combustion temperatures and relatively lower thermal NO_x emissions. These control options separately or in combination with another control option including SCR and SNCR are technically infeasible. The remaining NO_x control options cannot be eliminated based on technical infeasibility.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

Various information sources evaluated by the Department through the NO_x BACT analysis process assigned varying NO_x control efficiencies for each of the identified available NO_x control technologies/strategies. The following analysis uses the average of expected control efficiencies reported for each strategy:

NO_x Control Option	**NO_x Emission Rate (lb/MMBtu)**	**Estimated NO_x Control Efficiency**
CFB Boiler with SCR	0.014	90.00%
CFB Boiler with SNCR	0.07	50.00%
CFB Boiler without Controls	0.14	0.00%

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the NO_x control options on a CFB Boiler.

i. Environmental Impacts

The environmental impacts from both SCR and SNCR result from the handling of the anhydrous ammonia. Spent catalyst from an SCR will have to be properly disposed of as a possible hazardous waste. An SCR unit would have to be installed downstream of the baghouse to reduce fouling of the catalyst. Therefore, as an example, natural gas would have to be used to reheat the exhaust gas to optimal temperature for the SCR unit. The combustion of the natural gas would cause additional NO_x, CO, VOC, and PM_{10} emissions into the atmosphere. Even though there are environmental concerns associated with SCR and SNCR, these NO_x control options cannot be eliminated based on these concerns.

ii. Energy Impacts

SCR would cause significant backpressure in the CFB Boiler leading to lost boiler efficiency and, thus, a loss of power production. Along with the power loss, SME-HGS would be subject to the additional cost of reheating the exhaust gas, which would be expensive at the current price of natural gas. The energy impacts from an SNCR are minimal and an SNCR does not cause a loss of power output from the facility. Even though there are energy impact concerns with SCR, the control options cannot be eliminated based on these concerns. The impacts of additional cost due to reheating the exhaust gas are included in the annual cost of operating an SCR unit, which is presented in the economic impact analysis.

iii. Economic Impacts

Department verified economic impacts associated with NO_x control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for SCR and SNCR were derived from Chapter 4 in the *OAQPS COST Control Manual* (EPA 452/B-02-001). Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual, and if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for SNCR is approximately $2137/ton of NO_x removed and the cost effective value for SCR is

approximately $12,562/ton of NO_x removed. Based on the cost-effective values provided above, SNCR is deemed economically feasible for the affected unit and SCR is deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. NO_x BACT Determination

SME-HGS proposed the use of SNCR to maintain compliance with a proposed NO_x BACT emission limit of 0.07 lb/MMBtu (30-day rolling average). Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed NO_x emission control strategy and emission limit constitute BACT in this case. This BACT determined control option will provide an approximate 50% NO_x reduction efficiency.

SCR was eliminated based on the high cost per ton of NO_x removed. Further, since the SCR unit would have to be installed downstream from the permitted and BACT determined FFB to eliminate fouling and excessive loading of the catalyst, the CFB exhaust gas would need to be reheated. Reheating the exhaust gas is a significant factor in the high annual cost of SCR and leads to a substantial increase in emissions from the reheat process summarized. Finally, the Department is unaware of any CFB Boiler permitted or in operation in the United States, which has an SCR unit installed for NO_x emission control.

The BACT determined NO_x emission limit is equal to the lowest NO_x BACT emission rates contained in the RBLC. Further, two of the boilers permitted with NO_x BACT emission limits of 0.07 lb/MMBtu, respectively, are CFB Boilers that employ SNCR. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established NO_x BACT emission limit of 0.07 lb NO_x/MMBtu (30-day rolling average). Further, the Department determined that the periodic NO_x source testing, continuous NO_x emission monitoring, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted NO_x BACT limit(s).

4. CO Emissions

CO emissions from a CFB coal-fired boiler are typically controlled using proper design and combustion techniques. Typical CO control technologies (e.g., catalytic and thermal oxidizers) are available; however, they are not typically considered appropriate for coal-fired boilers because of high particulate loading, catalyst fouling, and/or high cost to reheat the exhaust gas.

A. Identification of Available CO Control Strategies/Technologies

The following control options are evaluated as available CO control options for the proposed SME-HGS project:

i. CFB Boilers with Proper Design and Combustion (no add-on control); and
ii. CFB Boilers with Catalytic or Thermal Oxidizers.

The following text provides a brief overview of the above-cited CO control options/technologies/strategies for the proposed project.

i. Proper Design and Combustion (No Add-On Control)

In an ideal combustion process, all of the carbon and hydrogen contained within the fuel is oxidized to carbon dioxide (CO_2) and water (H_2O). The emission of CO in a combustion process is the result of incomplete fuel combustion. Reduction of CO emissions can be accomplished by controlling the combustion temperature, residence time, and available oxygen. Normal combustion practice at the facility will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel usage. This efficiency of fuel combustion will also minimize CO formation.

ii. Catalytic or Thermal Oxidation of Post-Combustion Gases

Oxidizers or incinerators use heat to destroy CO in the gas stream. Incineration is an oxidation process that ideally breaks down the molecular structure of an organic compound into carbon dioxide and water vapor.

Temperature, residence time, and turbulence of the system affect CO control efficiency. A thermal incinerator generally operates at temperatures between 1,450 and 1,600ºF. Heat recovery between 35% and 70% can be realized with recuperative systems and up to 95% can be realized with regenerative systems. The thermal oxidation system analyzed for the main boiler is a regenerative thermal oxidation (RTO) system with 95% heat recovery. Regenerative systems are typically designed for exhaust flow rates between 10,000 and 100,000 standard cubic feet per minute (scfm). Recuperative systems are typically designed for exhaust flow rates between 500 and 50,000 scfm. Regenerative systems typically have higher capital costs than recuperative systems, but capital costs are typically offset by savings on auxiliary fuel use.

Catalytic incineration is similar to thermal incineration; however, catalytic incineration generally allows for oxidation at temperatures ranging from 600 to 1,000ºF and can achieve up to 70% heat recovery. The catalyst systems are typically metal oxides such as nickel oxide, copper oxide, manganese dioxide, or chromium oxide. Noble metals such as platinum and palladium may also be used. Fixed bed or fluid bed catalytic incinerators can be used on combustion exhaust streams and can achieve up to 70% heat recovery. A fixed bed catalytic incinerator with 70% heat recovery is examined in this BACT analysis because of its comparatively lower capital cost.

B. Technical Feasibility Analysis

For the purposes of this BACT analysis, proper design and combustion control and catalytic and thermal oxidation are considered technically feasible, although oxidation is not typically applied to coal-fired boilers. No available CO control options are eliminated due to technical infeasibility.

C. Ranking of Available and Technically Feasible CO Control Options by Efficiency

Various information sources evaluated by the Department through the CO BACT analysis process assigned varying CO control efficiencies ranging from 70% control for good combustion practices to 95% for the CO oxidation control

technologies/strategies. To be conservative, the SME-HGS application considered 90% control efficiency for the top oxidation control. The following table ranks the CO control options.

CO Control Option	**CO Emission Rate (lb/MMBtu)**	**Estimated Control Efficiency**
CFB Boiler with Thermal Oxidation	0.01	90%
CFB Boiler with Catalytic Oxidation	0.01	90%
CFB Boiler with Proper Design and Combustion Practices (no add-on control)	0.10	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the CO control options on a CFB Boiler.

i. Environmental Impacts

Catalytic oxidation results in adverse environmental impact from the handling of the spent catalyst, which may have to be disposed of as a hazardous waste. A catalytic oxidation unit would have to be installed downstream of the FFB to reduce fouling of the catalyst; therefore, the exhaust gas would require reheating to achieve optimal CO reduction. The combustion of the additional fuel for reheating purposes would cause an increase in NO_x, SO_2, CO, VOC, and PM_{10} emissions. However, the control options cannot be eliminated based on these concerns alone.

ii. Energy Impacts

The additional consumption of fuel to reheat the exhaust gas would result in energy impacts. With current market prices for fuel, this strategy would also be very expensive. Even though these energy impacts exist, the control options cannot be eliminated based on these concerns.

iii. Economic Impacts

Department verified economic impacts associated with CO control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for catalytic or thermal oxidation were derived from Section 3, Chapter 2 (9/2000) in the *OAQPS COST Control Manual*. Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for thermal oxidation is approximately $6916/ton of CO removed and the cost effective value for catalytic oxidation is approximately $4373/ton of CO removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. CO BACT Determination

SME-HGS proposed the use of good combustion practices with no additional control to maintain compliance with a proposed CO BACT emission limit of 0.10 lb/MMBtu (1-hr average). Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed CO emission control strategy and emission limit constitute BACT in this case.

Catalytic and thermal oxidation were eliminated based on the high cost per ton of CO removed and because the increased fuel consumption associated with reheating the gas stream would result in additional environmental impacts.

The BACT determined CO emission limit is equal to the lowest CFB Boiler CO BACT emission rates contained in the RBLC. Two non-CFB boilers listed in the RBLC have lower emission limits, but these two sources do not have a control device and rely on good combustion practices for CO control. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established CO BACT emission limit of 0.10 lb CO/MMBtu (1-hr average). Further, the Department determined that the periodic CO source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted CO BACT limit(s).

5. VOC Emissions

VOC emissions from a CFB coal-fired boiler are typically controlled using proper design and combustion techniques that were identified in the CO BACT analysis. Typical VOC control technologies (catalytic and thermal oxidizers) are available; however, they are not typically considered appropriate for coal-fired boilers because of high particulate loading, catalyst fouling, or high cost to reheat the exhaust gas.

A. Identification of Available VOC Control Strategies/Technologies

The following control options were evaluated for the CO control options and will be evaluated for the VOC control options. A description of each control technology is provided in the CO BACT analysis:

i. CFB Boilers with Proper Design and Combustion (no add-on control); and

ii. CFB Boilers with Catalytic or Thermal Oxidizers.

B. Technical Feasibility Analysis

For the purposes of this BACT analysis, proper design and combustion control, catalytic oxidation, and thermal oxidation will be considered technically feasible, although oxidation is not typically applied to coal-fired boilers. No available VOC control options are eliminated due to technical infeasibility.

C. Ranking of Available and Technically Feasible VOC Control Options by Efficiency

Various information sources evaluated by the Department through the VOC BACT analysis process assigned varying VOC control efficiencies ranging from 70% for good combustion practices to 95% for the VOC oxidation control technologies/ strategies. To be conservative, the SME-HGS application considered 90% control efficiency for the top oxidation control. The following table ranks the VOC control options.

VOC Control Option	**VOC Emission Rate (lb/MMBtu)**	**Estimated Control Efficiency**
CFB Boiler with Thermal Oxidation	0.0003	90%
CFB Boiler with Catalytic Oxidation	0.0003	90%
CFB Boiler with Proper Design and Combustion Practices (no add-on control)	0.003	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the VOC control options on a CFB Boiler.

i. Environmental Impacts

Catalytic oxidation results in adverse environmental impact from the handling of the spent catalyst and may have to be disposed of as a hazardous waste. A catalytic oxidation unit would have to be installed downstream of the FFB to reduce fouling of the catalyst; therefore, the exhaust gas would require reheating to achieve optimal VOC reduction. The combustion of the additional fuel for reheating purposes would cause an increase in NO_x, SO_2, CO, VOC, and PM_{10} emissions. However, the control options cannot be eliminated based on these concerns alone.

ii. Energy Impacts

The additional consumption of fuel would result in energy impacts from reheating the exhaust. With current market prices for natural gas, this strategy would also be very expensive. Even though these energy impacts exist, the control options cannot be eliminated based on these concerns.

iii. Economic Impacts

Department verified economic impacts associated with VOC control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for catalytic or thermal oxidation were derived from Section 3, Chapter 2 (9/2000) in the *OAQPS COST Control Manual*. Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual, and, if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for thermal oxidation is approximately $222,928/ton of VOC removed and the cost effective value for catalytic oxidation is approximately $142,546/ton of VOC removed. Based on

the cost-effective values provided above, all control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. VOC BACT Determination

SME-HGS proposed the use of good combustion practices with no additional control to maintain compliance with a proposed VOC BACT emission limit of 0.003 lb/MMBtu (1-hr average). Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed VOC emission control strategy and emission limit constitute BACT in this case.

Catalytic and thermal oxidation were eliminated based on the high cost per ton of VOC removed and because the increased fuel consumption associated with reheating the gas stream would result in additional environmental impacts.

The BACT determined VOC emission limit is among the lowest CO BACT emission rates contained in the RBLC for PC or CFB Boiler technologies. Further, the permitted VOC BACT emission rate of 0.003 lb/MMBtu matches recently permitted VOC BACT limits permitted for operation in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established VOC BACT emission limit of 0.003 lb VOC/MMBtu (1-hr average). Further, the Department determined that the periodic VOC source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted VOC BACT limit(s).

6. H_2SO_4, Acid Gases (HCl and HF), Trace Metals, and Condensable PM_{10} Emissions

Sulfuric acid mist, acid gases (primarily HF and HCl), and trace metals (including lead) are grouped together with condensable PM_{10} in this BACT evaluation because these pollutants are a major component of condensable PM_{10}. Other inorganic and organic species (e.g., ammonium bisulfate and certain VOCs) can also contribute to condensable PM_{10}. Control options for a CFB boiler are typically limited to the available SO_2 and/or filterable PM/PM_{10} control options.

H_2SO_4, acid gases (HCl and HF), trace metals (including lead), and condensable PM_{10} generally form in the exhaust system of a boiler. The formation is dependent upon several factors including residence time within specific temperature ranges, flue gas moisture content, combustion conditions, and concentrations of chlorine, fluorine, and trace metals in the coal.

<u>Sulfuric Acid Mist (H_2SO_4)</u>

H_2SO_4 is typically created when SO_3 in the flue gas reacts with water. SO_3 is formed during the combustion process in a coal-fired boiler. H_2SO_4 mist in boiler flue gas generally forms in three phases as described below:

Sulfur in the boiler fuel oxidizes to form sulfur dioxide (SO_2).

$$S + O_2 \rightarrow SO_2$$

A portion of the SO_2 further oxidizes to sulfur trioxide (SO_3).

$$SO_2 + ½ O_2 \rightarrow SO_3$$

SO_3 reacts with water in the exhaust stream or the atmosphere to form H_2SO_4.

$$SO_3 + H_2O \rightarrow H_2SO_4$$

Because H_2SO_4 mist is created in several steps, control strategies can be approached in a variety of ways that may be applied individually or in combination. Control strategies generally focus on reducing the amount of SO_2 and SO_3 in the flue gas, capturing sulfuric acid mist aerosol particles, and controlling exhaust system conditions to limit mist formation.

Acid Gases (HCl and HF)

Acid gases can be controlled to different degrees by standard control technologies for other criteria pollutants (primarily with SO_2 and filterable PM control technologies).

Trace Metals (Including Lead)

Depending on the physical and chemical properties of a metal and boiler combustion conditions, some metals can be emitted in the gas phase, while others may be emitted as particulates and will tend to be captured either in the fly or bed ash. Metals emitted from coal combustion include: arsenic, beryllium, cadmium, chromium, manganese, and lead and based on the physical and chemical properties of these listed metals, most would be emitted as particulate matter. A smaller percentage of these metals and other metals may also be emitted as volatiles and condensable particulates.

Condensable Particulate

Condensable particulate can be controlled to different degrees by controlling the components that make up condensable particulate (H_2SO_4 mist, acid gases, volatile trace metals, etc.) with standard control technologies for other criteria pollutants (primarily SO_2 and filterable PM control technologies).

A. Identification of Available H_2SO_4, Acid Gases (HCl and HF), Trace Metals, and Condensable PM_{10} Emissions Control Strategies/Technologies

Available control technologies for H_2SO_4 mist, acid gases (HCl and HF), trace metals (including lead), and condensable PM_{10} emissions from a CFB Boiler are listed below:

i. Wet FGD
ii. Wet FGD followed by wet ESP
iii. Dry FGD followed by FFB or ESP
iv. No additional add-on control

The following text provides a brief overview of the above-cited control options/technologies/strategies that have been evaluated for the proposed project.

i. Wet FGD

Wet FGD is limited in its ability to control H_2SO_4 mist and acid gas emissions for two reasons. First, the moisture inherent in the system, combined with the sudden cooling created by the slurry spray, tends to create sulfuric acid mist

and acid gases (two significant components of condensable PM_{10}). Second, because the condensable particulates are extremely small, they are not effectively captured by the washing action of the wet FGD. A wet FGD system would be expected to control sulfuric acid mist and acid gas (including HF) emissions with efficiency less than 25%.

ii. Wet FGD Followed by Wet ESP

Wet ESPs can control H_2SO_4 mist and acid gases with a very high efficiency. Not all of the SO_3 in the gas stream is converted to sulfuric H_2SO_4 mist, which results in an overall H_2SO_4 mist control efficiency for this system of approximately 90% (other acid gases will also be collected at an efficiency of 90%). Use of an FFB downstream of a wet scrubber is not technically feasible, the high moisture content of the flue gas exiting the scrubber would cause the filter cake to agglomerate, clogging the filter and making the filter cleaning extremely difficult.

iii. Dry FGD Followed by FFB or ESP

Dry FGD systems, including SDAs and fly-ash reinjection systems, are generally capable of controlling SO_3 (and H_2SO_4) and acid gases with an efficiency of at least 90%. As noted above, a particulate control device following a dry FGD system is required to collect the injected reagent particles. While ESPs and FFBs provide essentially the same level of particulate control, FFBs have the potential to enhance SO_2, SO_3, and HF removal efficiency as the exhaust gas passes through a filter cake containing alkaline ash and unreacted reagent. FFBs also have a high removal efficiency for trace metals and may provide some additional control for other acid gases.

B. Technical Feasibility Analysis

None of the identified available H_2SO_4, acid gas (HCl and HF), trace metals (including lead), and condensable PM_{10} control technologies are technically infeasible. Therefore, no available control options are eliminated at this stage.

C. Ranking of Available and Technically Feasible H_2SO_4, Acid Gas (HCl and HF), Trace Metals (including lead), and condensable PM_{10} Control Options by Efficiency

The following table summarizes the available control options, their respective potential control efficiency values, and their ranking for the purposes of this BACT analysis. Limited data is available on control efficiencies for these pollutants; therefore, the proposed CFB Boiler may not perform to the exact control efficiencies highlighted in the table.

Technology	**H_2SO_4 Control Efficiency**	**Acid Gas Control Efficiency**	**Trace Metal Control Efficiency**	**Condensable PM_{10} Control Efficiency**
Dry FGD & FFB or ESP	90%	80%	90%	90%
Wet FGD & Wet ESP	90%	90%	80%	90%
Wet FGD	25%	80%	70%	80%
No Add-On Control	---	---	---	---

The top two control alternatives potentially provide similar H_2SO_4 and condensable PM_{10} control efficiency, while the top two differ in acid gas and trace metal control efficiencies. Because SME-HGS proposes to implement one of these two top alternatives based on the SO_2 and filterable PM BACT analyses, no further analysis is required for H_2SO_4, acid gases, trace metals, and condensable PM_{10} control.

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The environmental, economic, and energy impacts associated with the available H_2SO_4, acid gas, trace metals, and condensable PM_{10} control options are the same as the impacts for those control options addressed in the BACT analyses for SO_2 and filterable PM emissions. Because these control strategies have been determined to constitute BACT for SO_2 and filterable PM, no additional environmental, economic, and energy impacts will be realized through the control of H_2SO_4, acid gas, trace metals, and condensable PM_{10}, through utilization of these co-benefit control strategies.

E. H_2SO_4, Acid Gas, Trace Metals, and Condensable PM_{10} BACT Determination

<u>H_2SO_4</u>

As previously stated, either of the two top technologies for H_2SO_4 mist control will reduce emissions by 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB to maintain compliance with a proposed H_2SO_4 BACT emission limit of 0.0054 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed H_2SO_4 emission control strategy and emission limit constitute BACT in this case.

This emission rate, although not the lowest, compares favorably to emission limits for similar facilities in the RBLC and is lower than the BACT-determined emissions rates for the recently permitted Gascoyne CFB Boiler and the two most recent coal-fired utilities permitted for operation in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established H_2SO_4 BACT emission limit of 0.0054 lb/MMBtu over any 1-hour time period. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

<u>Acid Gases</u>

As previously stated, either of the two top technologies for acid gas control will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB to maintain compliance with a proposed HF BACT emission limit of 0.0017 lb/MMBtu and a proposed HCl BACT emission limit of 0.0021 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed emission control strategy and emission limit(s) for HF and HCl constitute BACT in this case.

These BACT-determined acid gas emission rates, although not the lowest, compare favorably to emission limits for similar facilities in the RBLC, representing an average BACT emission rate for those sources contained in the RBLC. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established HF and HCl BACT emission limits of 0.0017 lb/MMBtu and 0.0021 lb/MMBtu, respectively, over any 1-hour time period. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

Trace Metals (including Lead)

As previously stated, either of the two top technologies for trace metals control will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB as BACT for trace metals. SME-HGS proposes the PM_{10} emission rate as a surrogate emission limit for trace metal emissions.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established PM_{10} surrogate emission limit of 0.026 lb/MMBtu. Further, the Department determined that the periodic source testing (PM_{10}) and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit.

PM_{10}

The PM_{10} emission rate is calculated based on the assumed components that make up the condensable PM_{10} fraction plus the BACT-determined filterable PM emission limit. The following table presents the emissions rates for the components that are assumed to make up the condensable PM_{10} fraction as well as the BACT-determined filterable PM emission rate.

Component	**Emission Rate (lb/MMBtu)**
HCl	0.0021
HF	0.0017
H2SO4	0.0054
VOC	0.0030
Ammonium Bisulfate	0.0015
Trace Metals	0.0002
Organic Condensables	0.0005
Total Condensables	**0.014**
Filterable PM	0.012
PM_{10} Limit	0.026*
* PM_{10} BACT-determined emission limit equals the condensable PM_{10} fraction plus the BACT-determined filterable PM limit	

As previously stated, either of the two top technologies for the pollutants making up the condensable PM_{10} fraction will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB to maintain compliance with a PM_{10} emission limit of 0.026 lb/MMBtu.

Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed emission control strategy and the Department-established emission limit for condensable PM_{10} constitutes BACT in this case.

The BACT-determined PM_{10} emission rate, although not the lowest, compares favorably to emission limits for similar facilities in the RBLC. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established PM_{10} emission limit of 0.026 lb/MMBtu. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

7. Mercury Emissions

Coal contains trace levels of a variety of metals and other elements or compounds. Mercury is one of those trace elements. Emissions of mercury into the atmosphere have been identified as a health concern principally due to its capacity to react chemically with the environment to form a toxic compound – methyl mercury – that accumulates through the aquatic food chain with a potential to threaten human populations. Depending on its chemical form, mercury can persist in the atmosphere and travel vast distances before being deposited on terrestrial features.

When coal burns, mercury is released in one of three forms, or species: elemental mercury vapor, oxidized mercury vapor, or mercury adsorbed to the surface of a solid particle. The different species of mercury respond differently to different types of control technologies.

Elemental mercury is the most difficult of the three mercury species to control. To date, no technologies have been demonstrated in field testing to consistently and significantly reduce elemental mercury emissions. Most research is focused on developing effective means for converting elemental mercury to one of the other two species of mercury.

Oxidized mercury is water soluble and generally more reactive than elemental mercury. Because of this, technologies for controlling SO_2 emissions have demonstrated promise for controlling oxidized mercury emissions as well. Research has shown a strong correlation between coal chlorine content and the proportion of oxidized mercury in coal combustion products. Under specific conditions, the addition of chlorine or other halides has been shown to promote mercury oxidation.

Particulate mercury may be controlled with FFBs and/or ESPs – devices commonly used to control particulate emissions from coal combustion processes. The proportion of particulate mercury emissions appears to be related to the amount of oxidized mercury. Oxidized mercury is more readily adsorbed to the surface of particles such as coal ash, FGD media, or activated carbon than is elemental mercury. Higher levels of unburned carbon (UBC) in the ash have also been shown to favor mercury adsorption.

Department of Energy, U.S. Environmental Protection Agency, and Industry Research

For the last several years the Department of Energy/National Energy Technology Laboratory (DOE/NETL) and the Electric Power Research Institute (EPRI) have evaluated mercury removal technologies for potential application to the power generation industry. However, the Department and SME-HGS have been unable to find research specifically evaluating control of mercury emissions from CFB Boilers.

A recent white paper from the EPA ("the technology review report") describes and summarizes the status of test programs throughout the country aimed at understanding and improving capabilities for reducing mercury emissions from coal-fired electric generators ("*Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update*," Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency; February 18, 2005). Results have varied greatly, from an actual increase of mercury emissions to over 90 percent mercury removal efficiency.

It has long been recognized that coal quality is a primary determining factor in mercury removal effectiveness. Bituminous coal generally contains higher levels of chlorine and UBC, and has therefore proven to provide enhanced capacity for mercury reduction. Conversely, subbituminous coal and lignite, often grouped as the single category of "low rank coal," generally contain low concentrations of chlorine and UBC. Control of mercury emissions resulting from combustion of these fuels has proven to be highly variable.

Mercury emissions control research, as it relates to coal-fired power generation, has followed two general paths: characterizing and enhancing co-benefits from existing control equipment (sometimes referred to as "native capture"), and development of mercury-specific control technologies. The two paths at times intermingle since mercury-specific control technologies often must be used in tandem with native capture. For example, modified or standard powdered activated carbon injection (ACI) is one of the most promising mercury-specific control technologies under certain conditions. Once injected into the exhaust stream, however, it must be captured by a particulate emissions control device. Following are some concluding observations from the EPA's technology review report:

- "Assuming sufficient RD&D of representative technologies, new and existing systems installed to control NO_x and SO_2 (e.g., SCR+FGD+FFB) have the potential to achieve 90%+ control of mercury for bituminous coal-fired boilers. Subbituminous and lignite systems appear to require mercury oxidation technology and/or additional advanced sorbents to achieve these levels."
- "It is believed that ACI and enhanced multi-pollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. Also, optimized multi-pollutant controls may be available in the 2010-2015 timeframe for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 90 and 95%."
- "The principle concerns relating to broad-scale use of mercury controls are the reliability of mercury reductions possible and the risks of adverse side effects. To the extent that required mercury reductions are within the capabilities of the technology with minimum risks of side effects, mercury controls could be considered available. However, as discussed in this paper, there remain some questions regarding their performance relative to broad-scale use. These questions are being investigated in ongoing efforts."

Project Coal Supply

SME-HGS is proposing to use Powder River Basin (PRB) subbituminous coal as the CFB Boiler fuel source. Specifically, SME-HGS is currently considering purchasing coal from one of the following three southeastern Montana coal mines: Spring Creek, Decker, and/or Absaloka coal mines. Coal quality data from two of these sources indicates average coal mercury content is 0.05-0.07 ppmw, compared with a national average of 0.17 ppmw ("Mercury in U.S. Coal – Abundance, Distribution, and Modes of Occurrence," USGS Fact Sheet FS-095-01, September 2001; available at pubs.usgs.gov/fs/fs095-01/fs095-01.pdf). The upper 95 percent confidence level mercury content value from these coal analyses is 0.13 ppmw. The corresponding uncontrolled mercury emission rate, assuming all of the mercury in the coal is released to the atmosphere, would be 10.0 lb/TBtu or 230 lb/yr.

A. Identification of Available Mercury Control Strategies/Technologies

The following paragraphs describe alternative technologies that are being evaluated for feasibility and effectiveness of controlling mercury emissions from electric utility boilers as presented in the 2005 EPA technology review report. The technologies are grouped into the following categories:

i. Native Controls:

a. Particulate Controls
b. SO_2 Controls
c. NO_x Controls
d. SDA/FFB Controls

ii. Enhanced Controls

a. Fuel Blending
b. Oxidizing Chemicals
c. UBC Enhancement
d. Mercury Specific Catalyst
e. Improvement of Wet FGD Mercury Capture

iii. Sorbent Injection: Add-on mercury control equipment; and

iv. Additional Alternatives

The following text provides a brief overview of the above-cited control options/technologies/strategies that have been evaluated for the proposed project.

i. Native Controls

Native controls include mercury removal accomplished by existing controls for NO_x, SO_2, and particulate.

a. Particulate Controls

Survey and test data indicate that ESPs provide limited mercury emissions control. Because the control they do provide results from the capture of particulate-bound mercury, its effectiveness depends on the relative

amount of particulate mercury speciation. FFBs have been demonstrated to be relatively more effective at controlling mercury emissions from bituminous and low rank coals. This appears to be due to the effect of the ash-cake that collects on the surface of the filters. The cake enhances gas-particle interactions, promoting adsorption of oxidized mercury and, where there is adequate chlorine, oxidation of elemental mercury.

b. SO_2 Controls

Wet FGD scrubbers have demonstrated mercury removal efficiencies ranging from less than 50% to approximately 75% for bituminous coal. No data were found that evaluated effectiveness when burning low rank coal. Because oxidized mercury – which is generally present in high proportion for bituminous coal – is water soluble, wet FGD removal effectiveness would be expected to be higher than has been observed. It is thought that wet FGD systems tend to promote chemical reduction of oxidized mercury to elemental mercury, resulting in subsequent re-emission.

While evaluations of mercury emissions from CFB Boilers do not appear in the literature, one of the primary advantages of CFB Boiler technology is the reduction of SO_2 emissions, which in turn may benefit mercury capture in the exhaust gas stream. Potential for mercury capture co-benefits associated with CFB technology will be addressed in a subsequent portion of this analysis.

c. NO_x Controls

SCR units appear to enhance oxidation of elemental mercury when burning bituminous coal, but limited data indicate marginal effectiveness when burning subbituminous coal.

d. SDA/FFB Systems

Emissions control systems consisting of spray dryer absorbers (SDAs) and FFBs have been demonstrated to provide over 90 percent mercury control efficiency for bituminous coal combustion. Average control efficiency when burning subbituminous coal is approximately 25 percent. This low effectiveness – less than has been observed with FFBs alone – is thought to be the result of HCl removal by the SDA. It is thought that bituminous coal contains enough excess chlorine that HCl scrubbing by the SDA is not a limiting factor for that coal rank.

ii. Enhanced Controls

Enhanced controls include mercury control strategies accomplished through the enhancement of existing controls.

a. Fuel Blending

Replacing a portion of PRB subbituminous coal with bituminous coal has been evaluated with mixed results ("Evaluation of Sorbent Injection for Mercury Control," Quarterly Technical Report, Reporting Period: April 1,

2005 – June 30, 2005; Sharon Sjostrom; available at www.netl.doe.gov/coal/E&WR /mercury/control-tech/sorbent-injection2.html.). In one short-term test, mercury capture increased from approximately 25 percent to nearly 80 percent. At another facility, no additional mercury capture was observed.

b. Oxidizing Chemicals

Limited short-term testing has been conducted on the effects of introducing chlorine and other halogens into the combustion system. The test results vary depending on boiler type, coal quality, and downstream pollution control equipment. Test results show some promise for adding these chemicals with ACI to achieve high levels of mercury emission reduction. However, further evaluation of impacts to operations and effectiveness over various conditions and durations has been recommended.

c. UBC Enhancement

Derivative data from field tests have provided evidence that increasing the portion of unburned carbon (UBC) in coal ash enhances mercury capture. Adjusting combustion conditions to increase ash UBC levels will require evaluation on a case-by-case basis of detrimental effects to boiler operation and efficiency.

d. Mercury-Specific Catalysts

Testing is ongoing regarding the effectiveness and feasibility of injecting oxidizing chemicals or employing catalyst systems designed to facilitate oxidation of elemental mercury.

e. Improvement of Wet FGD Mercury Capture

Limited testing has been conducted on the potential for SCR and an injected chemical additive to improve elemental mercury oxidation and to limit or eliminate chemical reduction of oxidized mercury in a wet FGD system. Results from the tests, which so far have been carried out only on bituminous coal, indicate that SCR and/or chemical additives can improve overall mercury capture in a wet FGD/ESP system firing bituminous coal.

iii. Sorbent Injection

Injection of various sorbents into the boiler exhaust stream has been the primary technology under evaluation that is specific to mercury control (i.e., it does not rely on a co-benefit of controlling some other pollutant). This technology was identified as having potential to reduce mercury emissions from coal-fired electric utility boilers because of its successful history of application to waste incinerators for the same purpose. Sorbent injection technology used in waste incinerators is not directly transferable to electric utility boilers, however, due to significant differences in operational requirements and in exhaust gas characteristics such as mercury concentrations, chemical makeup, and volume.

As suggested by the name, sorbent injection technology works by providing active surfaces that promote adsorption of exhaust mercury. The result is particulate-bound mercury that can be captured by particulate emissions control equipment such as an ESP or FFB. Standard ACI has proven to be effective for improving control of mercury emissions from bituminous coal on a relatively consistent basis. Its effectiveness on subbituminous coal emissions is dependent upon facility and operating parameters, and has been consistently lower than that observed with bituminous coal. Recent research suggests that the levels of chlorine and sulfur in the combustion gases are key in determining mercury capture efficiency.

Several alternative injection media have been and continue to be evaluated to address deficiencies and concerns associated with ACI. One class of alternative media consists of standard ACI that has been treated with a halogen, most commonly boron. The treatment serves to enhance elemental mercury oxidation and overall mercury adsorption. Initial results from several short-term tests indicate that halogenated ACI could potentially be more effective at mercury removal than standard ACI over a range of parameters while offering other benefits. Several evaluations of this technology are ongoing, and additional tests are planned.

Other specialty sorbent materials have been identified and are being evaluated for specific applications. These materials are being developed and evaluated primarily for the purposes of reducing control costs and improving potential for beneficial use of the collected ash.

iv. Additional Alternatives

An additional mercury control alternative, one that was not discussed in the EPA technology review report, is to treat the coal in order to remove a portion of its mercury prior to combustion. A joint venture company, the Alaska Cowboy Coal Power Consortium, has demonstrated in small-scale tests that their process for drying low rank coals can also remove a portion of the coal's mercury content. It has yet to be demonstrated on a full scale.

B. Technical Feasibility Analysis

The NSR Manual describes two key criteria for determining whether an alternative control technology is technically feasible. According to the NSR Manual, a technology must be "available" and "applicable" in order to be considered technically feasible. A technology is available "if it has reached the licensing and commercial sales stage of development." An identified alternative control technique may be considered presumptively applicable if "it has been or is soon to be deployed (e.g., is specified in a permit) on the same or similar source type." The following paragraphs evaluate the technical feasibility of the alternative control technologies identified above by applying these criteria of availability and applicability.

i. Native Controls

Insofar as technologies applied to control emissions of other pollutants also provide mercury control co-benefits, these technologies are considered technically feasible.

ii. Enhancement of Existing Controls

None of the native control enhancement technologies described above have demonstrated widespread applicability to coal-fired utility boilers on a full-scale basis. Further, and more importantly, none have been evaluated on any level for applicability to CFB Boiler technology. For these reasons, identified native control enhancement technologies are considered to be technically infeasible for application to the SME-HGS. The Department has recently determined that mercury capture enhancement technologies are generally not technically feasible. In the analysis of a recent permit for a PC electrical utility boiler the Department stated: "The Department determined that enhanced FGD is not currently an available control strategy and thus is not a suitable candidate for a full-scale mercury BACT control system at this time" (Montana Air Quality Permit #3185-02, Final: 05/16/05; page 29).

iii. Sorbent Injection

While sorbent injection technology has been tested under a variety of conditions, its applicability has not been demonstrated on a full-scale CFB Boiler. Based on two recently permitted coal-fired electrical generating units in Montana accepting conditions requiring ACI installation for mercury control and the availability of vendor guarantees on ACI, the Department determined that sorbent injection is available. The following citations provide further information regarding this determination. Also, under the current BACT analysis, SME-HGS proposed, and the Department required, mercury control equipment (IECS) that is equivalent to ACI/sorbent injection. Further, in accordance with the requirements of ARM 17.8.749, SME-HGS is required to install ACI or an equivalent technology (equivalent in removal efficiency), prior to commencement of commercial operations and operate ACI, or an equivalent technology (equivalent in removal efficiency), after a 6 month IECS operational period. The requirement for installation and operation of ACI does not constitute a BACT determination, in this case. Under the current permit action, the Department required the installation and operation of ACI based on comments submitted by SME-HGS during the public comment period on Permit #3423-00, which proposed ACI.

- The DOE Office of Fossil Energy has recently published a circular that describes ACI as the most promising near-term mercury control technology, but it qualifies that observation by stating that "the process applied to coal-fired boilers is still in its early stages and its effectiveness under varied conditions…is still being investigated"("Mercury Emissions Control R&D," updated June 21, 2005; available at http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/overview_mercurycontrols.html).
- As noted above, the EPA technology review document concludes, "It is believed that ACI and enhanced multipollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. Also optimized multi-pollutant controls may be available in the 2010-2015 timeframe for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 90 and 95%" ("Control of Mercury Emissions from Coal Fired Electric Utility Boilers:

An Update," Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency; February 18, 2005).

iv. Additional Alternatives

Coal drying, with the co-benefit of mercury removal, has not been proven on a large scale and is not commercially available. It is therefore not technically feasible.

C. Ranking of Available and Technically Feasible Mercury Control Options by Efficiency

The only remaining alternative mercury control technologies are those that provide mercury control co-benefits while reducing emissions of other pollutants. As noted above, the native controls that have been evaluated for mercury control effectiveness are wet and dry (or semi-dry) FGD scrubbers for SO_2 control; ESPs and FFBs for particulate control; and, to a lesser extent, SCR for NO_x control. These systems, individually and in combination, have demonstrated wide variability with respect to mercury reduction efficiency – anywhere from zero to over 90 percent. Effectiveness depends largely on coal quality (especially chlorine content), but also on a host of other design and operational parameters.

SME-HGS is proposing to control NO_x emissions with an SNCR system, SO_2 emissions by CFB technology that employs limestone and hydrated ash reinjection, and particulate emissions with an FFB. The combined air pollution control system is referred to as an integrated emissions control system (IECS). As part of evaluating the performance of CFB in combusting PRB coal, SME-HGS conducted a pilot-scale test burn in February 2005. The test burn was conducted in an ALSTOM Power test facility using 80 tons of Montana PRB coal and 20 tons of Montana limestone (80 tons of coal would be combusted in approximately 30 minutes in the SME-HGS main boiler when firing at full capacity). A summary of the test results is included in Section 3.12 of the application for this air quality permit and a complete copy of the test burn report is in Appendix I of the application for this air quality permit.

The pilot test results indicate a potential for approximately 88% (0.7 lb/TBtu) mercury removal in a CFB combustor with HAR and fabric filter controls. This level of mercury control is much greater than has been demonstrated for most utility boilers burning subbituminous coal and utilizing native control systems. It is also near the high end of values observed in the many test programs that have been and are being conducted on subbituminous coal combustion in utility boilers. However, the test burn alone does not provide sufficient data to allow boiler manufacturers to confidently extrapolate the data and guarantee mercury emissions control in a full-scale CFB unit with IECS.

Emissions testing at East Kentucky Power Cooperative Gilbert Unit 3, during the summer of 2005, included measurements of mercury emissions on a CFB Boiler equipped with an HAR, SNCR and FFB. Short-term testing results showed stack mercury emissions of 1.0 lbs/Trillion Btu (TBtu) and 89.5% control of the input mercury from coal. While these test results are very promising, Gilbert Unit 3 burns eastern bituminous coal with a relatively high chlorine content (0.031% during test period) from many different sources in Kentucky and Illinois. For comparison, Spring Creek coal has a chlorine content of <0.01%. Recent research

conducted by ADA-ES, with support from DOE/NETL, EPRI and industry partners, confirms that available chlorine is a key factor in oxidizing elemental mercury in the combustion gases and in controlling mercury emissions from PRB coal ("Full-Scale Evaluations of Mercury Control for Units Firing Powder River Basin Coals" Sjostrom, Sharon, *et al*., ADA-ES, O'Palko, Andrew, USDOE/NETL, Chang, Ramsay, EPRI. DATE not given).

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

For a discussion of collateral economic, energy, and environmental impacts associated with the proposed CFB Boiler and associated controls, refer to previous sections of this BACT analysis.

E. Mercury BACT Determination

SME-HGS proposed a mercury emissions floor and to conduct continuous mercury-specific monitoring of the CFB Boiler technology including limestone injection, SNCR, HAR, and FFB control, collectively termed the integrated emission control system (IECS), as mercury BACT for the proposed project. Further, as necessary, SME-HGS proposed the installation and operation of additional mercury emissions control technologies to establish scientifically justifiable and site-specific mercury emissions reductions above and beyond the permitted and BACT determined mercury floor emissions levels. The SME-HGS proposed mercury emissions floor was a maximum mercury emission rate expressed as either:

- 80% mercury reduction, based on a 12-month rolling average, or
- 2.0 lb mercury/TBtu, based on a 12-month rolling average.

Based on Department verified information contained in the SME-HGS application for this air quality permit, including mercury specific source testing results obtained through the simulated and comprehensive combustion, performance, and emission testing program conducted prior to application, and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed mercury emission control strategy and mercury floor emission limit(s) do not constitute BACT in this case. Considering the above-cited information as well as a recent mercury specific BACT determination for a similar source permitted for operation in Montana, the Department determined that the appropriate mercury BACT emissions limit(s) for the proposed project incorporating the IECS is either:

- 90% mercury reduction, based on a 12-month rolling average, or
- 1.5 lb mercury/TBtu, based on a 12-month rolling average.

The two-part limit accounts for two complementary operational factors. First, coal quality is not constant, even within a given coal deposit. At the extremely low values under consideration, a small proportional change in coal mercury content can have a significant impact in compliance potential. Second, control efficiencies generally decrease as inlet concentrations decrease, particularly as inlet concentrations become very low, as in the case of mercury concentrations in utility boiler exhaust. If SME-HGS should receive coal with higher than normal mercury content, it may be difficult to comply with the lb/TBtu limit, but compliance with the percent reduction requirement would be achievable. Conversely, if a particular coal supply contains less mercury than normal, the percent reduction requirement may be less readily attainable while the emission rate may be more so.

To confirm the performance of the CFB Boiler and IECS in reducing mercury emissions, SME-HGS will be required to monitor and analyze mercury control performance data after commencement of commercial operations and to report this information to the Department. The results of the final analysis will then be used to confirm compliance with the BACT-determined mercury emissions limit(s).

Also, in accordance with the requirements of ARM 17.8.749, SME-HGS is required to install ACI, or an equivalent technology, prior to commencement of commercial operations, as defined in 40 CFR 60, Subpart HHHH. SME-HGS will have 6 months following commencement of commercial operations to evaluate the mercury control effectiveness of the BACT-determined IECS. Further, and again in accordance with the requirements of ARM 17.8.749, after the 6 month IECS operating period, SME-HGS must operate the ACI system, or an equivalent technology (equivalent in removal efficiency). The requirement for installation and operation of ACI does not constitute a BACT determination, in this case. Through review of the proposed project, the Department determined that the installation and operation of ACI constitutes a mercury control strategy that is better than BACT, in this case. Under the current permit action, the Department required the installation and operation of ACI based on comments submitted by SME-HGS during the public comment period on Permit #3423-00, which proposed ACI.

8. Radionuclide Emissions

Most natural materials, including coal, contain trace quantities of radioactive components. When coal is combusted, radionuclides are contained in the combustion gases. Radionuclides from a CFB Boiler are emitted primarily as particulate matter. Pollution control equipment that is used to remove PM as described in the CFB Boiler filterable PM BACT determination will also effectively remove radionuclides. The Department determined that radionuclides can be controlled by more than 95% with traditional PM/PM_{10} control equipment (e.g., FFB or ESP).

A. Identification of Available Radionuclide Control Strategies/Technologies

The two most effective and available control options for radionuclides are an FFB and ESP as described in the CFB Boiler BACT determination for filterable PM emissions. Other less effective control options are also listed in the CFB Boiler BACT determination for filterable PM.

B. Technical Feasibility Analysis

FFB and ESP are technically feasible.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

FFB and ESP control options have the capability of controlling radionuclides by more than 95%, although FFBs are slightly more effective, particularly for smaller particulate matter.

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

Both FFB and ESP would produce a solid waste stream, with a wet ESP creating a wet solid waste stream. No significant environmental, economic, or energy impacts are identified as being associated with the use of an FFB or ESP, although an ESP

would require more energy than a FFB. In addition, when an FFB is downstream of a dry FGD unit, additional SO_2 is removed, along with acid gases and H_2SO_4 mist that have formed in the exhaust stream, thereby, providing additional co-benefit pollution control.

E. Radionuclide BACT Determination

SME-HGS proposed the use of an FFB as BACT for radionuclide emissions. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the FFB emission control strategy constitutes BACT for radionuclides in this case.

Because an FFB will achieve slightly better control than an ESP and FFB control is deemed BACT for filterable PM. The Department determined that the filterable PM BACT emission limit will act as a surrogate BACT emission limit for radionuclides. The BACT determination for radionuclides is consistent with previous Department BACT determinations for radionuclides. Further, the Department determined that the periodic source testing (filterable PM) and applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT requirements.

B. Coal, Limestone, and Ash (Fly and Bed Ash) Material Handling and Storage Operations BACT Analysis and Determination

The following BACT determination was conducted for PM/PM_{10} emissions resulting from both the handling and storage of coal, used as primary CFB Boiler fuel; limestone, used for CFB injection technology and SO_2 control; and ash (fly and bed-ash) produced by coal combustion in the CFB Boiler. The BACT analysis is broken down into two parts including material handling operations and material storage operations.

The Department reviewed the following control options, as well as previous BACT determinations for similar permitted sources in order to make the following pollutant specific BACT determinations.

1. Material Handling PM/PM_{10} Emissions

Material handling at the SME-HGS facility includes the transfer and conveying of coal, limestone, and ash. PM/PM_{10} emissions will be emitted from the conveying, handling, and transferring of these materials. The application for this permit lists all of the conveyors and material handling transfer points located throughout the SME-HGS facility.

Typically, limestone and coal are moved within a facility using belt conveyors and bucket elevators. Ash is typically moved via pneumatic conveyors. Both methodologies have the potential to create particulate emissions.

As the flow of material passes through the transfer or drop point to a conveyor, particulate emissions are generated. The quantity of particulate emissions generated by a transfer point varies with the volume of material passing through the point, the particle size distribution of the material, the moisture content of the material, and the exposure to prevailing winds at the transfer point. EPA's AP-42, Section 13.2.4 describes a methodology and provides equations to calculate uncontrolled particulate emissions from both batch and continuous process transfers, or drop point transfers, with an emission factor rating of A, giving the equation the highest level of confidence.

A. Identification of Available PM/PM_{10} Control Strategies/Technologies

Methods of controlling particulate emissions from conveyors and transfer points have been developed, which can significantly reduce emissions rates. These methods are based on several principles: reducing the amount or flowrate of material passing through the transfer point, passing larger sized material and minimizing the small particle size content of the material, increasing the moisture content of the material to increase agglomeration of fine material, and shielding or enclosing the transfer point to protect the transfer point from wind. Enclosures often include fan-powered FFB to collect any airborne particulate at a common point for re-use or disposal.

As previously stated, there are a number of available control technologies that can theoretically be employed to control PM/PM_{10} emissions from materials handling sources. The following table summarizes available controls for PM/PM_{10} emissions from conveyors and transfer points.

Technology	**Description**
Wet Dust Suppression / Wetted Material	A water spray or fogger with or without surfactant hadds water to the material being handled. Emissions are prevented through agglomerate formation by combining small dust particles with larger particles or with liquid droplets. Water retained by the material prevents emissions from storage systems and downstream transfers.
Enclosure (including partial enclosure)	Structures or underground placement can be used to shelter conveyors and material transfer points from wind to prevent particulate entrainment. Enclosures can either fully or partially enclose the source.
Enclosure with ESP	Conveyors can be enclosed and have emissions-laden air collected from the enclosure and ducted to an ESP. An ESP uses electrical forces to move entrained particles in the air onto a collection surface. A cake of particulate forms on the collection surface, which is periodically "rapped" by a variety of means to dislocate the particulate, which drops down into a hopper for collection and disposal or reuse.
Enclosure with FFB	Conveyors are often enclosed and emissions-laden air is collected and ducted to the FFB. Pneumatic conveyors are typically sealed with the exception of a FFB or bin vent on the air discharge. In either case, the air-flow passes through tightly woven or felted fabric, causing particulates in the flow to be collected on the fabric by sieving and other mechanisms. As particulate collects on the filter, collection efficiency increases. However, as the dust cake thickness increases so does the pressure drop across the bags. Bags are intermittently cleaned by mechanisms such as shaking the bag, pulsing air through the bag, or temporarily reversing the airflow direction. Material cleaned from the bags is collected in a hopper at the bottom of the FFB.

B. Technical Feasibility Analysis

The technologies listed in the above table are considered technically feasible, with the following exceptions. Since the proposed emergency coal storage pile is not enclosed, having an enclosed transfer point to the pile is considered technically

infeasible. As a result, adding FFB or ESP to the enclosure is also considered technically infeasible; therefore, these strategies are removed from further consideration for that transfer point.

Ash handling from temporary storage (e.g., silo) to permanent storage (e.g., monofill) by enclosure with ESP or FFB control is not an industry accepted practice. Fly ash consists primarily of fine particles, which easily become airborne, and bed ash has a significant portion of fine particles. These materials are not suitable for collection with these listed technologies, as the baghouse or ESP will pick up a significant portion of the material stream and quickly become overloaded. Therefore, these strategies are removed from further consideration for ash handling.

C. Ranking of Available and Technically Feasible PM/PM_{10} Control Options by Efficiency

The following table summarizes the available control options, their respective potential control efficiency values, and their ranking for the purposes of this BACT analysis.

Technology	**Estimated Control Efficiency**	**Rank**
Enclosure with FFB	99.5%	1
Enclosure with ESP	Up to 99%	2
Enclosure	Varies with Degree of Enclosure 3-Sided Enclosure = 50% Complete Enclosure = 90%	3
Wet Dust Suppression (including water spray with or without surfactant and wet material	50%	4
No Add-On Control	---	5

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text provides a brief discussion of the available control options and an analysis of BACT applicability in this case.

i. Enclosure with FFB

For most of the proposed sources, an enclosure with FFB dust collector control has been deemed technically feasible. FFB operations and maintenance are relatively simple. FFB are generally considered an industry standard for material transfer point particulate control and are deemed economically feasible in this case. Because FFB provides the highest level of control, no further evaluations are necessary for sources with proposed FFB control.

ii. Enclosure with ESP

Because ESPs can theoretically attain up to 99% control efficiency, ESP control was evaluated. The ESP could only be used to control the limestone and ash particulate emissions and not for coal handling because of the high explosion potential of coal dust collection in an ESP. ESPs are not typically used for control of limestone or ash handling emissions due to the high initial costs of installation, complexity, and technical difficulty of operations. Costs associated with the technical obstacles have not been quantified in this analysis. Industry norms indicate, however, that use of ESPs for particulate

control from material handling transfer points is unduly complex and cost prohibitive. Therefore, the use of enclosures with an ESP is eliminated from further consideration in this BACT analysis.

iii. Enclosures

Using enclosure structures or underground placement to shelter material from wind entrainment is often an economical means to control PM/PM_{10} emissions. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure. Enclosures are considered for the coal pile reclaim hopper, belt feeder and transfer to Conveyor CC03. All of this equipment is located underground, and covered by the coal pile. The emergency storage pile has no regularly scheduled use. Only a very small fraction of the total coal consumed at the SME-HGS facility is anticipated to go through the storage pile. As such, the cost of providing additional control by the installation of an enclosure is difficult to quantify and would result in relatively large cost/ton effectiveness figures. Complete enclosure provides the highest level of control of the remaining alternatives.

iv. Wet Dust Suppression

Wet dust suppression works by causing fine particles to agglomerate through the introduction of moisture into the material stream. The agglomerated particles resist entrainment by wind. Because use of wet dust suppression techniques, including fogging water spray with or without surfactant, can achieve control efficiency of 50% or greater, wet dust suppression was evaluated.

Wet dust suppression is not always a practical control alternative. Occasionally, moisture may interfere with further processing such as screening or grinding where agglomeration is counterproductive. In addition, application of additional moisture in fuel handling operations can increase fuel costs and/or cause upset combustion conditions. In some cases, water may not be readily available and piping water to the site may be cost-prohibitive. Finally, using water sprays when the temperatures are below freezing causes operational difficulties.

When using wet dust suppression, the decision to use or not to use surfactants is often somewhat discretionary and based on availability of a water source. Addition of surfactants to the water lowers its surface tension and improves wetting efficiency. As a result, less water is used and application is required less frequently. Wet dust suppression is particularly applicable to ash handling activities. Ash is often mixed with small quantities of water in a pug mill before disposal.

E. Material Handling PM/PM_{10} Emissions BACT Determination

SME-HGS proposed the use of the highest level of control that is technically and practically feasible for the affected material handling PM/PM_{10} emission sources. Proposed BACT for coal, limestone, and ash handling conveyors will be partial or full enclosures. Coal/limestone belt conveyors will be partially enclosed with a cover that extends past the conveyor belt, or is fully contained within a building. The limestone bucket elevator conveyors will be fully enclosed, and the ash handling pneumatic conveyors will be fully enclosed and sealed.

SME-HGS proposes to use enclosures with FFB or bin vent control as BACT for PM/PM_{10} on almost all of the material transfer emission points. Enclosure with a baghouse or bin vent provides the most effective control and is considered the industry norm for control of materials handling transfer points. Based on Department verified information contained in the application for this permit, the following exceptions to the material transfer point BACT determination of FFB or bin vent control apply in this case: complete enclosure is BACT for PM/PM_{10} on the transfer points at the emergency coal pile to reclaim hoppers, reclaim hopper to belt feeder, and belt feeder to Conveyor CC03 because FFB or ESP control would not be cost-effective due to the relatively low potential to emit of the sources since the transfer points are located beneath (i.e., underground) the emergency coal pile. Further, enclosures for these sources is the most cost effective control given the infrequent operation of the equipment.

Further, the Department determined that wet dust suppression constitutes BACT for PM/PM_{10} emissions from the fly ash and bed ash conveyor and transfer emission points (removal from the silo). The FFB, ESP, and enclosure control options are technically infeasible. SME-HGS proposed wet dust suppression for ash handling after the pug mill for removal from the plant collection system. SME-HGS proposed wet dust suppression and partial enclosure (i.e., lowering well) for the transfer of coal to the emergency coal storage pile because the FFB and ESP control options are practically infeasible for a single transfer point that will operate intermittently.

A review of the EPA's RBLC database shows that the proposed BACT presented in the sections above conforms to controls required for similar sources recently permitted under the PSD program. The data from the RBLC website is summarized in the application.

The Department determined that the affected material handling and transfer points operating under the proposed control requirements and the established FFB and bin vent emission limit(s) of 0.005 gr/dscf and 0.01 gr/dscf, respectively, constitute BACT in this case. Further, the Department determined that the periodic PM/PM_{10} source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material transfer BACT requirements.

2. Material Storage PM/PM_{10} Emissions

Materials stored at the SME-HGS facility include coal, limestone, fly ash and bed ash. Particulate emissions will be emitted from the storage of these materials. Storage of these materials in large quantities, as required by a coal-fired power plant of this size, has historically been accomplished with piles. More recently, control technologies have been applied to the storage of these materials.

Sections 13.2.4 and 13.2.5 of AP-42 describe the process by which storage piles generate fugitive particulate emissions. The quantity of particulate emissions generated by a storage pile varies with several factors, including wind speed acting upon the surface of the pile, threshold friction velocity of the pile, frequency of disturbance of the pile, and area of disturbance of the pile. Threshold friction velocity takes into account materials makeup of the pile, material size distribution and moisture content of the material in the pile. Emissions are generated only when the wind speed acting upon the pile exceeds the friction threshold velocity.

A storage pile of aggregate material, such as coal, limestone or ash, is typically composed of pieces of material of different sizes, including non-erodible elements of the material (greater than 1 cm in diameter) mixed with smaller, erodible material sizes, including silt. The pile surface has a limited amount of the erodible portion of material, which tends to be removed from the pile rapidly during a wind event. This is referred to as erosion potential of the pile. Since undisturbed piles quickly lose their potential for erosion during a wind gust, emissions are significantly reduced until the pile is disturbed, when the erosion potential is restored. If a crust is formed on the pile due to erosion, precipitation, water spray or surfactant application, the emission potential is significantly reduced because of the resulting increase of the threshold friction velocity of the pile.

Methods of controlling particulate emissions from the storage of materials have been developed which can significantly reduce fugitive emissions from storage of materials. These methods are similar to the transfer point emissions reduction methods, and are based on several principles:

- Minimizing material transfers to and from the pile (pile disturbances),
- Storing larger sized material and minimizing the small particle size content of the material,
- Increasing the moisture content of the material to increase agglomeration and cementation of fine material to larger particles, and
- Shielding or enclosing the materials to protect from wind erosion

Enclosures may include fan-powered fabric filter baghouses or un-powered bin vent filters to collect airborne particulate.

A. Identification of Available PM/PM_{10} Control Strategies/Technologies

A number of available control technologies can theoretically be employed to control PM/PM_{10} emissions from materials storage. The following table summarizes available controls for PM/PM_{10} emissions.

Technology	Description
Inactive Storage Pile with No Additional Control	An inactive storage pile minimizes or eliminates disturbances which reduces the erosion potential of the pile. It also allows a crust to form on the pile over time, which helps resist erosion by increasing the pile's threshold friction velocity.
Inactive Storage Pile with Wind Fence	An inactive pile with a wind barrier or wind fence builds upon the control listed above by reducing the wind speed that acts upon the pile surface. This minimizes the number of times that the wind velocity exceeds the threshold friction velocity, thereby reducing the number of emission events or the duration of emission events.
Inactive Storage Pile with compaction, a Permanent Wet Suppression System and Wind Fence	An inactive pile with compaction and wet suppression builds upon the control listed for an inactive storage pile alone. Compaction and wet suppression actively promote the formation of a crust on the pile by increasing the amount of agglomeration or cementing of the surface materials. This significantly increases the threshold friction velocity of the surface and reduces erosion potential. This strategy works especially well with materials that bond together with water application, such as ash. Wind fences may or may not be applied with this option depending on the additional control a wind fence may add to the overall control of this option.
Enclosure	Using structures or underground placement to shelter material from wind entrainment. Enclosures can either fully or partially enclose the source.
Enclosure with FFB or Bin Vent	Emissions-laden air is collected from the enclosure and ducted to the FFB or bin vent. The flow passes through tightly woven or felted fabric, causing particulates in the flow to be collected on the fabric by sieving and other mechanisms. As particulate collects on the filter, collection efficiency increases. However, as the dust cake thickness increases so does the pressure drop across the bag.

B. Technical Feasibility Analysis

All of the potentially applicable control technologies listed above are considered technically feasible for the storage of coal, limestone, and ash.

C. Ranking of Available and Technically Feasible PM/PM_{10} Control Options by Efficiency

The following table summarizes the available options, their respective potential effectiveness values, and their ranking for this BACT analysis.

Technology	Estimated Control Efficiency	Rank
Enclosure with FFB or bin vent	99.5%	1
Inactive Storage Pile with compaction, a Permanent Wet Suppression System and Wind Fence	95%	2
Inactive Storage Pile with Wind Fence	Varies with Degree of Enclosure 3-Sided Enclosure = 50% Complete Enclosure = 90%	3
Enclosure	50%	4
Inactive Storage Pile with Best Management Practices	25-90%	5
Active Storage Pile with No Add-On Control	---	6

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text provides a brief discussion of the available control options and an analysis of BACT applicability in this case.

i. Enclosure with FFB or Bin Vent

If a storage system is completely enclosed, a FFB or bin vent can usually be added to the enclosure to more efficiently control particulate emissions. FFBs or bin vents on enclosures are generally considered an industry standard for particulate control on enclosed, active aggregate storage systems. Enclosures (silos) with bin vent control are proposed by SME-HGS for short-term coal storage, limestone storage and short-term ash storage. SME-HGS proposed to use enclosure and FFB or bin vent control for all active coal, limestone, and ash storage.

ii. Enclosures

Enclosure structures to shelter material from wind entrainment are often used to limit particulate emissions from stored aggregate materials. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure. Enclosures for aggregate materials often come in the form of walls around a pile, storage buildings or silos. Enclosures are generally not sealed and have emissions associated with adding and removing materials. Active storage piles are often enclosed. Inactive storage piles are generally not enclosed.

iii. Inactive Storage Pile with Permanent Wet Suppression System and Wind Fence

Applying wet dust suppression to an inactive pile contributes greatly to crust formation, which maximizes particle agglomeration on the pile surface. The agglomerated particles resist entrainment by wind on the pile surface, and minimize particulate emissions. Wet dust suppression is not without its drawbacks. Occasionally, moisture may interfere with further processing such as screening or grinding where agglomeration is counterproductive. In addition, application of additional moisture in fuel handling operations can increase fuel costs and/or cause upset combustion conditions. Using water sprays when the temperatures are below freezing causes operational difficulties. Piles are usually not watered when the ambient temperature is below freezing.

When using wet dust suppression, the decision to use or not to use surfactants is often somewhat discretionary and based on availability of a water source. Addition of surfactants to the water lowers its surface tension and improves wetting efficiency. As a result, less water is used and application is required less frequently. In the case of the coal pile, application of surfactants may be required to achieve 90% control efficiency.

iv. Inactive Storage Pile with Wind Fence

An inactive storage pile can be protected from prevailing winds with a wind barrier or wind fence. A properly designed wind barrier can effectively reduce wind speeds at the pile surface by 20 – 60%. The wind barrier should be as

high as the pile, and at least as wide as the pile to achieve maximum effectiveness. Reducing wind speed acting on the pile surface reduces particle entrainment and thereby reduces particulate emissions from the stored material.

v. Inactive Pile with Best Management Practices

Using an inactive storage pile with best management practices generally includes initial compaction of material by bulldozer or other tracked heavy equipment, minimizing the number of pile disturbances, minimizing the frequency of pile disturbances, minimizing the surface area of the pile, and applying wet dust suppression to disturbed areas of the pile to help re-form a crust as necessary to reduce fugitive emissions.

vi. Active with No Additional Control

The Department determined that it is not modern, standard industry practice to store coal or ash in an active pile without further emissions controls. Recent BACT determinations show that additional control on active or inactive piles is warranted.

SME-HGS proposed to use enclosure and baghouse or bin vent control for all active coal, limestone and ash storage. Since this option has the highest degree of particulate control, no economic analysis of this option has been performed for active storage. Economic impacts associated with the PM/PM_{10} control options for inactive storage piles of coal and ash listed above were compared using estimated annualized capital, operating, and maintenance costs. Cost estimates were supplied by SME-HGS and its engineering contractors. If data was not available from SME-HGS, best engineering judgment was used. Detailed information regarding economic impacts is contained in the application for this air quality permit.

E. Material Storage PM/PM_{10} Emissions BACT Determination

SME-HGS proposed to use a combination of enclosures (silos) with bin vent control for active storage of coal, limestone, and ash, and best management practices for the emergency coal storage and ash storage. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed PM/PM_{10} emission control strategies and applicable emission limits constitute BACT in this case. The following table lists the proposed BACT control requirements and emissions limits, as applicable.

Material Stored	**Method**	**Applicable Limit**
Active Coal Storage	Coal Silo and Coal Bunkers with FFB Control	0.005 gr/dscf
Inactive Coal Storage – Emergency Coal Storage Pile	Inactive Storage Pile with Best Management Practices	NA
Limestone Storage	Limestone Silo and Limestone Bunkers with FFB Control	0.005 gr/dscf
Short-Term Ash Storage	Fly-Ash Silo and Bed-Ash with bin vent Control	0.01 gr/dscf
Long-Term Ash Storage	Inactive Storage Pile with Best Management Practices until Monofill is Capped	NA

Based on Department verified information contained in the application and taking into consideration technical, environmental, and economic factors, the Department determined that enclosure in silos with FFB or bin vent control for active coal, limestone, and short-term ash storage constitutes BACT in this case. Enclosure with FFB or bin vent control provides the highest level of particulate control, with reasonable costs and minimal adverse environmental impacts. Normal material flow consists of loading the coal and limestone bunkers on a daily basis from the enclosed coal and limestone silos, through the tripper conveyor system. The bunkers will be enclosed and controlled by baghouse DC4. The coal silo will be enclosed and controlled by baghouse DC2. The limestone silo will be enclosed and controlled by baghouse DC5. After the fly ash is removed from the FFB associated with the boiler exhaust gas stream, the ash will be temporarily stored in ash silo AS1, which is enclosed and controlled by a bin vent filter, DC6. Bed ash removed from the boiler will be temporarily stored in the bed ash silo AS2, which is enclosed and controlled by bin vent DC7.

Based on Department verified information contained in the application and taking into consideration technical, environmental, and economic factors, the Department determined that an inactive storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application) constitutes BACT for emergency reserve storage of coal and long-term storage of ash prior to capping of the open on-site ash storage cell. SME-HGS will be submitting, separate from the air quality permit application, a solid waste management plan for the long-term storage of the ash in the monofill. Based on the emission inventory prepared for the SME-HGS facility, the inactive emergency coal storage pile is estimated to emit 1.63 tons per year of PM_{10} (based on conservative emission calculations). Recent PSD permitting actions show this storage method constitutes BACT. The Department determined that the addition of a wind fence or permanent wet suppression system to the inactive coal pile yields a minimal additional control of particulate emissions once the coal pile is compacted and becomes encrusted. The cost analysis supplied in the application for this air quality permit shows that the control options with higher particulate control have extremely high costs on a dollar per ton of PM_{10} removed basis. Detailed information regarding the cost analysis is contained in the application for this permit action. The Department determined that these costs are excessive and far above industry norms for PM_{10} control. Therefore, all additional control options above best management practices for inactive coal storage have been eliminated from further consideration under this BACT analysis.

Based on Department verified information contained in the application, the Department determined that an inactive storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application), constitutes BACT for storage of ash prior to capping of the open monofill cell. SME-HGS proposed to mix fly ash and bed ash with small quantities of water in the pug mill after removal from the ash silos. The ash-water mixture is hauled to the ash monofill, where it is pushed into location and compacted. Ash, when mixed with small quantities of water, forms a cement-like material that has very low wind erosion potential. The monofill is composed of cells, formed by excavating earthen material from the cell location and using that material to form a berm around the monofill cell. The monofill has a “built-in” wind barrier, due to the construction of the monofill cells, which are partially below grade and considered “bermed.”

Based on the emission inventory prepared for the SME-HGS facility, the inactive ash storage pile is estimated to emit 1.62 tons per year of PM_{10} (based on conservative emission calculation equations). All of the additional controls identified in the application for this permit yield minimal particulate removal with extremely high cost effective values. Detailed information regarding the cost analysis is contained in the application for this permit action. Therefore, the BACT analysis eliminates these methodologies on an economic basis. Although the RBLC database does not explicitly show any BACT determinations for ash storage or disposal in a monofill, the Department determined that an inactive ash storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application) constitutes BACT in this case.

The proposed BACT technologies conform to controls required for similar sources recently permitted under the PSD program that are listed in the RBLC database. The data from the RBLC website is summarized in the application.

The Department determined that the affected material storage emission sources operating under the proposed control requirements and the established FFB and bin vent emission limit(s) of 0.005 gr/dscf and 0.01 gr/dscf, respectively, constitute BACT in this case. Further, the Department determined that the periodic PM/PM_{10} source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material storage BACT requirements.

C. Cooling Tower PM/PM_{10} Emissions BACT Analysis and Determination

A wet cooling tower will be used at the SME-HGS facility to dissipate waste heat from the generating system. The proposed cooling tower will be a fan-induced draft, counter-flow design. Latent heat of water evaporation is used to provide the cooling effect. The design circulating water rate is 102,800 gallons per minute (gpm). Approximately 2,250 gpm of the cooling water will be evaporated by the cooling tower.

The cooling tower provides direct contact between the cooling water flow and air passing through the tower. Some of the cooling water becomes entrained in the air stream and carried out of the tower as water droplets (in liquid phase). Water lost in the liquid phase is known as “drift.” The drift loss is independent of water lost to evaporation. When the drift droplets evaporate, dissolved solids crystallize and create particulate emissions. The particulate emissions consist of mineral matter and chemicals used for corrosion control in the piping systems. PM/PM_{10} emissions from the cooling tower are estimated in the emissions inventory at 13.5 tons per year.

Factors that affect PM/PM_{10} emission rates from wet cooling towers include: air and water flow patterns, the amount of total dissolved solids (TDS) in the cooling cycle water, circulating water volumes, the number of cooling tower concentration cycles and operation and maintenance practices.

The Department reviewed the following control options, as well as previous BACT determinations for similar permitted sources in order to make the following pollutant specific BACT determinations.

1. Identification of Available PM/PM_{10} Control Strategies/Technologies

   The Department is aware of only one control technology for PM_{10} emissions from wet cooling towers: drift eliminators. Drift eliminators work by intercepting as many water droplets as possible from the airflow leaving the cooling tower, thus minimizing PM_{10} emissions. Drift eliminators are designed to cause sudden directional changes to the air flow and the inertia of the water droplets causes them to impact the eliminator surfaces. The drift is then collected and returned to the cooling water flow. The drift eliminators also help minimize the amount of make-up water required for the cooling tower cycle operation. High efficiency drift eliminators of modern design can control the drift to less than 0.005% of the cooling tower circulating water flow.

2. Technical Feasibility Analysis

   Drift eliminators are technically feasible and commonly employed for wet cooling tower operations such as that proposed by SME-HGS.

3. Ranking of Available and Technically Feasible PM/PM_{10} Control Options by Efficiency

   The only available PM/PM_{10} control strategy/technology identified for the proposed cooling tower is a drift eliminator. Drift eliminators are capable of an approximate 90% reduction in particulate emissions resulting from wet cooling tower operations.

4. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

   The cooling tower design proposed by SME-HGS incorporates high efficiency drift eliminators. Because this control technology is effective and constitutes the only available PM/PM_{10} control efficiency, no further analysis is required.

5. Cooling Tower PM/PM_{10} Emissions BACT Determination

   Drift eliminators for cooling tower PM/PM_{10} control will reduce emissions by at least 90%. SME-HGS proposes to install, operate and maintain high efficiency drift eliminators on the cooling tower. The proposed design includes a drift rate of 0.002% circulating flow. The resulting potential PM/PM_{10} emission rate is 3.09 lb/hr, or 13.52 tons per year. This is equivalent to a normalized rate of 0.50 pounds of PM_{10} emitted per million gallons of circulating water (lbs/MMgal).

   The BACT determined PM/PM_{10} emission rate of 0.002% of circulating flow is one of the lowest values reported in the RBLC for other recently permitted and similar sources. The data from the RBLC website is summarized in the application.

   The Department determined that the installation, operation and maintenance of high efficiency drift eliminators on the cooling tower and a PM/PM_{10} emission limit of 0.002% of circulating flow constitute BACT in this case. Further, the Department determined that the periodic PM/PM_{10} source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material storage BACT requirements.

D. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed BACT Analysis and Determination

The following BACT analysis evaluates NO_x, CO, SO_2, PM/PM_{10}, and VOC emissions from the intermittent and limited use of the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater for support and emergency operations at the SME-HGS facility.

The Auxiliary Boiler will run on #2 diesel fuel-oil, natural gas, or propane and will be operated only during startup, shutdown, and commissioning of the CFB Boiler and during extended downtimes of the CFB Boiler during the winter months to aid in the prevention of freezing of the CFB Boiler components. The Emergency Generator and Emergency Fire Pump will run only on #2 diesel fuel oil and operate only during emergencies and during required equipment maintenance. The Coal Thawing Shed Heater will operate only on propane or natural gas during times when the coal is frozen in the coal train cars.

The Department reviewed the following control options, as well as previous BACT determinations for similar permitted sources in order to make the following pollutant specific BACT determinations.

1. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed NO_x Emissions

   NO_x will be formed during the combustion of natural gas, propane, or diesel fuel in the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater. Three fundamentally different mechanisms produce NO_x during the combustion of hydrocarbon fuels. The formation of NO_x is dominated by the thermal mechanism, which involves the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most of the "thermal NO_x" is formed in the high temperature flame zone near the burners or in the combustion chambers. The amount of thermal NO_x formed is directly proportional to oxygen concentration, peak temperature, and time of exposure to peak temperature. Virtually all thermal NO_x is formed in the region of the flame at the highest temperature. Maximum thermal NO_x production occurs at a slightly lean fuel-to-air ratio due to the excess availability of oxygen for reaction with the nitrogen in the air and fuel.

   A second mechanism for the formation of NO_x, termed "prompt NO_x," occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals present in the fuel. The prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of thermal NO_x. However, prompt NO_x levels may become significant when technologies are applied that control thermal NO_x to ultra-low levels.

   A third mechanism, "fuel NO_x," stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. The contribution of this mechanism to the total NO_x depends entirely on the nitrogen content in the fuel. For natural gas, propane, and fuel oil, the contribution of fuel NO_x is usually negligible.

   A. Identification of Available NO_x Control Strategies/Technologies

      NO_x emissions from the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater can be reduced by several different methods. The following list presents methods listed in the RACT/BACT/LAER database and other technologies that are applicable to natural gas combustion processes:

i. Selective Catalytic Reduction (SCR);
ii. Selective Non-Catalytic Reduction (SNCR);
iii. Low Temperature Oxidation (LoTOx);
iv. Dry Low NOX (Staged Combustion);
v. Non-Selective Catalytic Reduction (NSCR);
vi. Wet Controls;
vii. Innovative Catalytic Systems (SCONOX and XONON);
viii. Process Limitations; and
ix. Proper Design (no additional control).

These control technologies may be applied individually or in combination. A brief discussion of each type of control technology that was not presented in the Main Boiler NOx BACT is presented below.

i. SCR

A detailed discussion of SCR NO_x control technology is included in the CFB Boiler NO_x BACT analysis.

ii. SNCR

A detailed discussion of SNCR NO_x control technology is included in the CFB Boiler NO_x BACT analysis.

iii. Low Temperature Oxidation ($LoTO_x$)

Oxygen and nitrogen are injected at ~380°F to transform NO and NO_2 into N_2O_5 using an ozone generator and a reactor duct. N_2O_5, which is soluble, dissociates into N_2 and H_2O in a wet scrubber. Requirements of this system include a wet scrubber, oxygen, and a cooling water supply. Scrubber effluent treatment must also be provided. The estimated control efficiency of the system is 80-90%.

iv. Dry Low NO_x

Dry technologies may be identified as dry low NO_x (DLN) burners, dry low emissions (DLE), or $SoLoNO_x$. These technologies incorporate multiple stage combustors that may include premixing, fuel-rich zones that reduce the amount of O_2 available for NO_x production, fuel-lean zones that control NO_x production through lower combustion temperatures, or some combination of these. A quench zone may also be present to control gas temperature. Almost all new process heaters/boilers presently being manufactured incorporate these technologies into their combustor designs to some extent. These systems typically result in 40-60% reduction in NO_x.

v. Non-Selective Catalytic Reduction

An NSCR unit controls NO_x emissions by using available CO and residual hydrocarbons in the exhaust of a rich-burn internal combustion engine as an NO_x reducing agent. Without the catalyst, in the presence of oxygen, the hydrocarbons will be oxidized instead of reacting with the NO_x. As the excess hydrocarbon and NO_x pass over a honeycomb or monolithic catalyst (usually a combination of noble metals such as platinum, palladium, and/or rhodium), the reactants are reduced to N_2, H_2O, and CO_2.

The noble metal catalyst usually operates between 800°F and 1,200°F; therefore, the unit would normally be mounted near the engine exhaust to maintain a high enough temperature to allow the various reactions to occur. In order to achieve maximum performance, 80% to 90% reduction of NO_x concentration, the engine must burn a rich fuel mixture, causing the engine to operate less efficiently. The NSCR can be applied only to rich-burn engines and not to the Auxiliary Boiler.

vi. Wet Controls

Water or steam injection technology has been well demonstrated to suppress NO_x emissions from gas turbines, but it is not commonly used to control NO_x on process heaters or boilers. The injected fluid increases the thermal mass by dilution and thereby reduces peak temperatures in the flame zone. NO_x reduction efficiency increases as the water-to-fuel ratio increases. For maximum efficiency, the water must be atomized and injected with homogeneous mixing throughout the combustor. This technique reduces thermal NO_X, but may actually increase the production of fuel NO_x. Depending on the initial NO_x levels, wet injection may reduce NO_x by 60% or more.

vii. Innovative Catalytic Systems

Innovative catalytic technologies integrate catalytic oxidation and absorption technology. In the $SCONO_x$ process, CO and NO are catalytically oxidized to CO_2 and NO_x; the NO_2 molecules are subsequently absorbed on the treated surface of the $SCONO_x$ catalyst. Ammonia is not required. The limited emissions data for this process reflects that there is an associated increase in HAP emissions when applying this technology. $SCONO_x$ technology has recently been applied to combined cycle turbine generation facilities, since steam produced by a heat recovery steam generator (HRSG) is required in the process.

The XONON system is applicable to diffusion and lean-premix combustors. It utilizes a flameless combustion system where fuel and air react on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion system consists of the partial combustion of the fuel in the catalyst module followed by completion of combustion downstream of the catalyst. Initial partial combustion produces no NO_x and downstream combustion occurs in a flameless homogeneous reaction that produces almost no NO_x. The system is totally contained within the combustor and is not an add-on control device. This technology has not been fully demonstrated.

viii. Process Limitations

The amount of NO_x and other pollutants formed by fossil fuel combustion can be reduced proportionately by limiting operating hours or reducing fuel consumption.

B. Technical Feasibility Analysis

Innovative catalytic systems typically installed on combustion turbines are technically infeasible to install on the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater.

LoTOx and wet controls are technically impractical on the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater as these types of control options have never been installed on emergency use equipment and equipment in intermittent use. SCR and SNCR are classified as technically infeasible on small emergency use equipment. These controls are brought forward for the Auxiliary Boiler and Coal Thawing Shed Heater since these units are planned to operate more frequently and potentially for longer durations than the emergency equipment.

DLN technology is technically infeasible on spark or compression ignition reciprocating internal combustion engines. Therefore, DLN is eliminated from use on the Emergency Generator and Emergency Firewater Pump.

NSCR technology is technically infeasible on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because an NSCR technology requires a lean oxygen exhaust stream (<1% O_2). These four units will operate with a rich oxygen exhaust stream.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

The following table ranks the available and technically feasible control options according to control effectiveness and includes the no additional add-on control and process limitations control strategies.

NO_x Control Option	**Auxiliary Boiler and Coal Thawing Shed Heater Control Efficiency**	**Emergency Generator and Emergency Fire Water Pump Control Efficiency**
SCR	80-90%	Technically Infeasible
NSCR	Technically Infeasible	Technically Infeasible
DLN (Auxiliary Boiler only)	40-60%	Technically Infeasible (Except Coal Thawing Shed Heater)
SNCR	40-60%	Technically Infeasible
Process Limitations	Varies with Limitation	Varies with Limitation
Proper Design (no additional Control	N/A	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the NO_x control options for the Auxiliary Boiler or Coal Thawing Shed Heater that would eliminate the control option. The application provides a detailed economic evaluation for the Auxiliary Boiler. No economic cost analysis is provided for the Coal Thawing Shed Heater because the only add-on control option is a DLN burner, which will be employed on the heater.

The control efficiency used for the SCR was 90%, SNCR was 50%, and DLN was 50%. The DLN equipment cost for the Auxiliary Boiler was provided by Nebraska Boilers, and the DLN equipment cost for the Coal Thawing Shed Heater was based on a ratio of the Auxiliary Boiler DLN cost and the heat input values for the Auxiliary Boiler and Coal Thawing Shed Heater. The SCR and SNCR equipment costs were derived from equations in OAQPS Section 4 – NO_x Controls (10/2000). Capital costs were annualized at 10% for 10 years as recommended by OAQPS. As reported in the application, the Auxiliary Boiler cost effective value for SCR is approximately $36,925/ton of NO_x removed; for SNCR the cost effective value is approximately $18,514/ton NO_x removed; and for DLN the cost effective value is approximately $1341/ton NO_x removed. The Coal Thawing Shed Heater cost effective value for SCR is approximately $158,172/ton of NO_x removed; for SNCR the cost effective value is approximately $179,635/ton NO_x removed; and for DLN the cost effective value is approximately $16,678/ton NO_x removed. Based on the cost-effective values provided above, the Department determined that DLN constitutes a cost-effective control option for the Auxiliary Boiler in this case. Further, based on the cost-effective values provided above, all control options are deemed economically infeasible for the Coal Thawing Shed Heater in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed NO_x Emissions BACT Determination

Based on the annual cost-effectiveness of DLN, the Department determined that NO_x BACT control for the Auxiliary Boiler is DLN burners with process limits in this case. Further, based on Department verified information contained in the application for this air quality permit and the NO_x BACT analysis summarized previously, the Department determined that NO_x BACT for the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater is proper design and combustion practices and process limitations. The unit specific process limitations are included in the following table.

Combustion Unit	**Process Limitation**	**Annual Hours of Operation**
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any NO_x emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will operate only during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Fire Water Pump and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential NO_x impact associated with enforceable limitations. However, in order to protect the ambient

air quality impact analysis conducted for this air quality permit, the Department determined that non-BACT NO_x emission limit(s) of 46.79 lb/hr for the Auxiliary Boiler and 41.20 lb/hr for the Emergency Generator are necessary.

2. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed CO Emissions

A. Identification of Available CO Control Strategies/Technologies

Control of CO and VOC can be achieved through oxidation of post-combustion gases with or without a catalyst. The following is a list of available CO control technologies:

i. Oxidation Catalyst;
ii. Thermal Oxidation;
iii. NSCR;
iv. Process Limitations; and
v. Proper Design (no additional control).

The oxidation catalyst and thermal oxidation control options are described in detail in the CFB Boiler BACT analysis. NSCR has been described in the NO_x BACT analysis in the previous section. NSCR has the ability to control NO_x and CO from rich-burn internal combustion engines.

B. Technical Feasibility Analysis

NSCR technology is technically infeasible on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because an NSCR technology requires a lean oxygen exhaust stream (<1% O2). These four affected units will operate with a rich oxygen exhaust stream. The other available CO control options are technically feasible.

C. Ranking of Available and Technically Feasible CO Control Options by Efficiency

The following table ranks the control options according to control effectiveness.

CO Control Options for Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater	**Percent Reduction**
Catalytic Oxidation	80-90%
Thermal Oxidation	80-90%
Process Limitation	Varies with Limitation
Proper Design and Operation (no add-on control)	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the CO control options for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater that would eliminate the control option. The application for this air quality permit provides an economic evaluation for the four affected emitting units. The control efficiency for thermal and catalytic incineration is 90% and equipment costs were derived from the equation in OAQPS Chapter 2 –

Incinerators (9/2000). Capital costs were annualized at 10% for 10 years as recommended by OAQPS. As reported in the application, the Auxiliary Boiler cost effective value for thermal oxidation is approximately $78,794/ton of CO removed and the catalytic oxidation cost effective value is approximately $64,829/ton CO removed. The Emergency Generator cost effective value for thermal oxidation is approximately $157,653/ton of CO removed and the catalytic oxidation cost effective value is approximately $280,198/ton CO removed. The Emergency Fire Water Pump cost effective value for thermal oxidation is approximately $354,202/ton of CO removed and the catalytic oxidation cost effective value is approximately $585,551/ton CO removed. The Coal Thawing Shed Heater cost effective value for thermal oxidation is approximately $163,320/ton of CO removed and the catalytic oxidation cost effective value is approximately $253,926/ton CO removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed CO Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the CO BACT analysis summarized previously, the Department determined that CO BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is proper design and combustion practices and the process limitations included in the following table.

Combustion Unit	**Process Limitation**	**Annual Hours of Operation**
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any CO emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will operate only during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential CO impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis conducted for this air quality permit, the Department determined that a non-BACT CO emission limit of 18.6 lb/hr for the Auxiliary Boiler is necessary.

3. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed SO_2 Emissions

A. Identification of Available SO_2 Control Strategies/Technologies

The following is a list of available SO_2 control technologies.

i. Wet or dry FGD;
ii. Low sulfur fuels;
iii. Process limitations; and
iv. No additional control.

Wet and dry flue gas desulfurization control options are described in the SO_2 CFB Boiler BACT. Using low sulfur fuels such as propane, pipeline quality natural gas, and low sulfur diesel is an effective SO_2 emissions control strategy.

B. Technical Feasibility Analysis

Wet and dry FGD on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater are considered technically infeasible because these emitting units will be intermittently operating on gaseous or liquid fuel with low sulfur concentrations. Wet and dry FGD are typically employed on solid fuel or gaseous and liquid fuel that have high sulfur contents and high potential SO_2 emissions. Natural gas, propane, and #2 diesel fuel oil are required by regulation to have relatively low sulfur concentrations. Therefore, the Department determined that wet and dry FGD control options are considered technically infeasible for the control of SO_2 from the affected units in this case.

C. Ranking of Available and Technically Feasible SO_2 Control Options by Efficiency

The following table ranks the available and feasible SO_2 control options according to control effectiveness.

SO_2 Control Options	**Percent Reduction**
Low Sulfur Fuels	Varies
Process Limitations	Varies with Limitation
No Additional Controls	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No economic, environmental, or energy impacts exist for the available and feasible SO_2 control options that would eliminate the control options from further evaluation. An economic analysis is not provided for the remaining control options listed because SME-HGS proposed the use of low sulfur fuels and process limitations.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed SO_2 Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the SO_2 BACT analysis summarized previously, the Department determined that SO_2 BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is the combustion of low sulfur fuels only and the process limitations included in the following table.

Combustion Unit	Process Limitation	Annual Hours of Operation
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any SO_2 emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will operate only during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential SO_2 impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis conducted for this air quality permit, the Department determined that a non-BACT SO_2 emission limit of 12.63 lb/hr for the Auxiliary Boiler is necessary.

4. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed PM/PM_{10} Emissions

A. Identification of Available PM/PM_{10} Control Strategies/Technologies

The following is a list of available PM/PM10 control technologies.

i. Fabric Filter Baghouse;
ii. Electrostatic Precipitator;
iii. Low Ash Fuels;
iv. Process Limitations; and
v. No Additional Control.

Fabric filter baghouses and ESPs are described in the PM/PM_{10} Main Boiler BACT.

B. Technical Feasibility Analysis

Fabric filter baghouses are technically infeasible control options for the emergency generator and emergency fire water pump because the exhaust temperature is too hot for fabric filter bags. The remaining available control options are assumed to be technically feasible for the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater. All of the available control options are technically feasible for the Auxiliary Boiler.

C. Ranking of Available and Technically Feasible PM/PM_{10} Control Options by Efficiency

The following table ranks the available and feasible PM/PM_{10} control options according to control effectiveness.

PM/PM_{10} Control Technology	**Percent Reduction**
FFB (Auxiliary Boiler and Coal Thawing Shed)	99%+
ESP (Auxiliary Boiler and Coal Thawing Shed)	99%+
Low Ash Fuels	Varies with Limitation
Process Limitations	Varies with Limitation
No Additional Controls	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the PM/PM_{10} control options that would eliminate the control options for any of the affected emitting units. An economic impact analysis is provided for FFB and ESP control options for the Auxiliary Boiler and Coal Thawing Shed Heater based on cost data provided in the EPA fact sheets for FFB and ESP control. As reported in the application, the Auxiliary Boiler cost-effective value for FFB is approximately $153,981/ton PM/PM_{10} removed and the cost-effective value for ESP is approximately $230,971/ton PM/PM_{10} removed. The Coal Thawing Shed Heater cost-effective value for FFB is approximately $922,141/ton PM/PM_{10} removed and the cost-effective value for ESP is approximately $1,383,212/ton PM/PM_{10} removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed PM/PM_{10} Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the PM/PM_{10} BACT analysis summarized previously, the Department determined that PM/PM_{10} BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is process limitations, as indicated in the following table.

Combustion Unit	**Process Limitation**	**Annual Hours of Operation**
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any PM/PM_{10} emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will operate only during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential PM/PM_{10} impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis conducted for this air quality permit, the Department determined that a non-BACT PM/PM_{10} emission limit of 3.22 lb/hr for the Auxiliary Boiler is necessary.

5. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed VOC Emissions

A. Identification of Available VOC Control Strategies/Technologies

Control of VOC emissions can be achieved through oxidation of post-combustion gases with or without a catalyst. The following is a list of available VOC control technologies.

i. Oxidation Catalyst;
ii. Thermal Oxidation;
iii. Process Limitations; and
iv. Proper Design (no additional control).

The oxidation catalyst and thermal oxidation VOC control options are described in detail in the CFB Boiler BACT analysis.

B. Technical Feasibility Analysis

Thermal and catalytic oxidation as well as process limits are considered technically feasible for all of the affected units.

C. Ranking of Available and Technically Feasible VOC Control Options by Efficiency

The following table ranks the control options according to control effectiveness.

VOC Control Options for Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater	**Percent Reduction**
Catalytic Oxidation	80-90%
Thermal Oxidation	80-90%
Process Limitation	Varies with Limitation
Proper Design and Operation (no add-on control)	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the VOC control options for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater that would eliminate the control option. The application for this air quality permit provides an economic evaluation for the four affected

emitting units. As reported in the application, the Auxiliary Boiler cost effective value for thermal oxidation is approximately $1,198,837/ton of VOC removed and the catalytic oxidation cost effective value is approximately $983,985/ton VOC removed. The Emergency Generator cost effective value for thermal oxidation is approximately $1,206,310/ton of VOC removed and the catalytic oxidation cost effective value is approximately $980,693/ton VOC removed. The Emergency Fire Water Pump cost effective value for thermal oxidation is approximately $3,317,579/ton of VOC removed and the catalytic oxidation cost effective value is approximately $4,098,854/ton VOC removed. The Coal Thawing Shed Heater cost effective value for thermal oxidation is approximately $2,462,650/ton of VOC removed and the catalytic oxidation cost effective value is approximately $3,724,499/ton VOC removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed VOC Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the VOC BACT analysis summarized previously, the Department determined that VOC BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is proper design with process limitations, included in the following table.

Combustion Unit	**Process Limitation**	**Annual Hours of Operation**
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any VOC emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will operate only during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the affected unit operations do not warrant emission limitations due to limited potential VOC impact associated with enforceable limitations.

E. Vehicle Traffic/Haul Roads PM/PM_{10} Emissions BACT Analysis and Determination

Fugitive PM/PM_{10} emissions will be generated at the SME-HGS facility by vehicle travel in and around the plant site. The Department determined that SME-HGS must use reasonable precautions to limit the fugitive emissions of airborne particulate matter on haul roads, access roads, parking areas, and the general plant property. SME-HGS proposed to pave the roads and parking areas around the main complex of buildings at the site to allow for unimpeded traffic flow during wet and muddy conditions. The roads farther from the site complex (e.g., the haul road to the ash monofill) will be unpaved.

As previously discussed, SME-HGS proposed to use a combination of paved and unpaved roads at the site. The Department determined that reasonable precautions including the application of water and/or chemical dust suppressants, as necessary, to the unpaved roads and the sweeping of paved roads, as necessary, constitutes BACT in this case. This is common industry practice and is typically considered BACT for fugitive road dust resulting from vehicle traffic at industrial sites.

F. CFB Boiler Refractory Brick Curing Heaters (2771 MMBtu/hr)

Section II.M.1-4 of the permit incorporates enforceable operational limits and a maximum heat input capacity limit for the proposed propane-fired CFB Boiler refractory curing heater(s). Because these enforceable operational limits restrict the allowable operating time, type of fuel, and heat input capacity of the affected units, potential emissions of all regulated pollutants from CFB Boiler refractory brick curing heater(s) operations are limited. Given the limited potential to emit of the CFB Boiler refractory curing heater(s), the Department determined that add-on control equipment would be cost prohibitive. Therefore, the Department determined that normal operation within the permit limits contained in Section II.M of the permit constitutes BACT for the affected unit(s), in this case.

The control options selected include controls and have control costs comparable to the controls required for other recently permitted similar sources and the options selected are capable of achieving the appropriate emission standards.

IV. Emission Inventory

ton/year											
Emission Source	**PM**	**PM_{10}**	**NO_x**	**SO_x**	**CO**	**VOC**	**Pb**	**Hg**	**HCl**	**HF**	**H_2SO_4**
CFB Boiler (2626 MMBtu/hr)	138.0*	299.1	805.2	437.1	1150.2	34.5	0.28	0.017	24.15	19.55	62.11
Aux. Boiler (225 MMBtu/hr)	1.4	1.4	19.9	5.4	7.9	0.5	---	---	---	---	---
Emergency Generator	0.13	0.13	10.3	0.3	0.7	0.2	---	---	---	---	---
Emergency Fire Water Pump	0.04	0.04	0.9	0.03	0.2	0.03	---	---	---	---	---
Coal Thawing Shed	0.03	0.03	1.0	0.00	0.17	0.03	---	---	---	---	---
Car Unloading Baghouse (DC1)	24.4	24.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Silo Baghouse (DC2)	3.6	3.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Crusher Baghouse (DC3)	2.8	2.8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tripper System Baghouse (DC4)	3.8	3.8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limestone Baghouse (DC5)	5.0	5.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fly-Ash Silo Bin Vent (DC6)	1.5	1.5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bed-Ash Silo Bin Vent (DC7)	1.4	1.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Pile Dressing	1.7	0.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Coal Pile Transfers	3.4	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Coal Pile Storage	3.3	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ash Landfill (Truck Dump)	3.2	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	13.53	13.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heavy Truck Traffic	4.8	1.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Building Heaters	0.28	0.28	9.72	0.01	1.32	0.35	---	---	---	---	---
Fuel Oil Storage Tank	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
Refractory Brick Curing Heaters (2771 MMBtu/hr)	3.05	3.05	96.65	0.09	16.28	2.36	---	---	---	---	---
Total Emissions	**215**	**366**	**944**	**443**	**1177**	**38**	**0.28**	**0.02**	**24.15**	**19.55**	**62.11**

* CFB Boiler PM emissions represent only front-half filterable PM emissions. Total PM emissions including PM_{10} and condensable PM emissions are estimated under the column for CFB Boiler PM_{10} emissions.

A complete emission inventory for Permit #3423-00 is on file with the Department

CFB Boiler Emissions

Heat Input: 2626.1 MMBtu/hr (Average Annual Heat Input – Manufacturers Information)
Hours of Operation: 8760 hr/yr (Annual Potential)

Filterable PM Emissions

Emission Factor: 0.012 lb/MMBtu (BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.012 lb/MMBtu = 31.51 lb/hr
31.51 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 138.03 ton/yr

PM_{10} Emissions (filterable and condensable)

Emission Factor: 0.026 lb/MMBtu (BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.026 lb/MMBtu = 68.28 lb/hr
68.28 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 299.06 ton/yr

NO_x Emissions

Emission Factor: 0.07 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.07 lb/MMBtu = 183.83 lb/hr
183.83 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 805.16 ton/yr

SO_x Emissions

Emission Factor: 0.038 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.038 lb/MMBtu = 99.79 lb/hr
99.79 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 437.09 ton/yr

CO Emissions

Emission Factor: 0.10 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.10 lb/MMBtu = 262.61 lb/hr
262.61 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1150.23 ton/yr

VOC Emissions

Emission Factor: 0.003 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.003 lb/MMBtu = 7.88 lb/hr
7.88 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 34.51 ton/yr

Hg Emissions

Emission Factor: 1.50E-06 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 1.50E-06 lb/MMBtu = 0.0039 lb/hr
0.0039 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.017 ton/yr

HCl Emissions

Emission Factor: 0.0021 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0021 lb/MMBtu = 5.51 lb/hr
5.51 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 24.15 ton/yr

HF Emissions

Emission Factor: 0.0017 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0017 lb/MMBtu = 4.46 lb/hr
4.46 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 19.55 ton/yr

H_2SO_4 Emissions

Emission Factor: 0.0054 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0054 lb/MMBtu = 14.18 lb/hr
14.18 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 62.11 ton/yr

V. Existing Air Quality

The air quality classification for the SME-HGS project area is "Unclassifiable or Better than National Standards" (40 CFR 81.327) for the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. However, the facility will locate in an area that has recently been re-designated attainment for CO under a limited maintenance plan. The SME-HGS facility has not been identified in any studies as impacting the previous CO nonattainment area.

Under the requirements of the PSD program, SME-HGS was required to conduct modeling to determine pollutant-specific pre-monitoring applicability. Because air modeling showed that the concentration of PM_{10} exceeded the level identified in ARM 17.8.818(7), SME-HGS was required to conduct on-site pre-monitoring for this pollutant. SME-HGS collected PM_{10} pre-monitoring data at the proposed site from November 12, 2004, through November 11, 2005. The following table lists the background monitoring data from the SME-HGS PM_{10} monitoring site. The measured PM_{10} values establish the baseline concentrations and demonstrate compliance with all applicable ambient air quality standards.

PM_{10} Pre-monitoring Results

Pollutant	Avg. Period	High Impact (ppm)	High Impact ($\mu g/m^3$)	HSH Impact (ppm)	HSH Impact ($\mu g/m^3$)	Ambient Standard[a] ($\mu g/m^3$)	% of Standard
PM_{10}	24-hr	------	23	------	19	150	13
	Annual	------	7	------	------	50	14

[a] MAAQS and NAAQS

VI. Ambient Air Impact Analysis

The nearest PSD Class I area is the Gates of the Mountains Wilderness Area located approximately 53 miles [85 kilometers (km)] southwest of the proposed site. Impacts have also been evaluated at these other Class I areas within 250 km of the site: Scapegoat Wilderness Area, Bob Marshall Wilderness Area, Glacier National Park, Mission Mountains Wilderness Area, UL Bend Wilderness Area, and Anaconda Pintler Wilderness Area. Bison Engineering, Inc. (Bison) submitted modeling on behalf of SME-HGS.

Emissions of NO_x, SO_2, CO, PM_{10}, $PM_{2.5}$ and Pb were modeled to demonstrate compliance with the NAAQS and Montana Ambient Air Quality Standards (MAAQS) and the PSD increments. On December 15, 2006, the Departmemt received revised modeling of the HGS facility. The new modeling is based on the changed footprint of the facility, which will be permitted at both the original and the alternative footprint. Changing the locations of the emission points within the property boundary had very little impact on the modeled impacts. The original modeling followed the model selection criteria contained in Appendix W of 40 CFR 51, Guideline on Air Quality Models (revised), April 15, 2003. The revised modeling followed the November 9, 2005 version of Appendix W, with the primary change being the use of the AERMOD model instead of the older ISC-PRIME model. SME's original Class II modeling used five years of surface meteorological data

(1984, 1986-1991) collected at the Great Falls Airport National Weather Service (NWS) station. The AERMOD modeling for the alternative location used EPA SCRAM hourly surface data from the Great Falls NWS site for the years 1999-2003. Surface met data was processed with corresponding upper air data from the Great Falls NWS station. The highest impact from the two modeling submittals is listed for each pollutant and averaging period in the tables below.

SME-HGS submitted a significant impact analysis based on emissions from all proposed SME-HGS sources, including the CFB Boiler refractory brick curing heater(s) proposed under the supplemental preliminary determination. The modeled SME-HGS impacts are compared to the applicable Class II significant impact levels (SIL's) in Table 1. The SILs are contained in Table C-4 of the NSR Manual. The impacts exceed the SIL's for PM_{10}, NO_x and SO_2; therefore, a cumulative impact analysis is required for these pollutants to demonstrate compliance with the NAAQS/MAAQS. The radius of impact (ROI) for each pollutant and averaging period is included in Table 1.

Table 1: SME Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. ($\mu g/m^3$)	Class II SIL[a] ($\mu g/m^3$)	Significant (y/n)	Radius of Impact (km)
PM_{10}	24-hr	18.7	5 (1)[b]	Y	3.0
	Annual	3.1	1	Y	1.4
NO_x [c]	Annual	1.6	1	Y	0.7
CO	1-hr	90.3	2,000	N	------
	8-hr	26.9	500	N	------
SO_2	3-hr	15.9	25	N	------
	24-hr	7.4	5 (1)[b]	Y	0.7
	Annual	0.24	1	N	------
O_3	Net Increase of VOC: 35.6 tpy. Less than 100 tpy, source is exempt from O_3 analysis.				

[a] All concentrations are 1st-high for comparison to SIL's.
[b] If a proposed source is located w/in 100 km of a Class I area, an impact of 1 $\mu g/m^3$ on a 24-hour basis is significant.
[c] Significant impact area (SIA) based on NO_x impact (rather than NO_2).

NAAQS/MAAQS modeling was conducted for PM_{10}, SO_2, and NO_x. CO impacts from SME-HGS alone were below the modeling significance level and no additional modeling was conducted for CO emissions. The full ambient impact analysis included emissions from other industrial sources in the Great Falls area.

Modeling results are compared to the applicable NAAQS/MAAQS in Table 2. Modeled concentrations show the impacts from SME-HGS and off-site sources and include the background values. As shown in Table 2, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 2: SME-HGS NAAQS/MAAQS Compliance Demonstration

Pollu-tant	Avg. Period	Modeled Conc.[a] ($\mu g/m^3$)	Backgrnd Conc. ($\mu g/m^3$)	Ambient Conc. ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS	MAAQS ($\mu g/m^3$)	% of MAAQS
PM_{10}	24-hr	10.5	23	33.5	150	22	150	22
	Annual	3.2	7	10.2	50	20	50	20
$PM_{2.5}$	24-hr	10.3[e]	23	33.3	35	95	---	---
	Annual	2.31[e]	7	9.31	15.0	62	---	---
NO_2	1-hr	240[b]	75	315	------	------	564	56
	Annual	2.0[c]	6	8.0	100	8.0	94	8.5
SO_2	1-hr	87.2	35	122	------	------	1,300	9.4
	3-hr	44.3	26	70.3	1,300	5.4	------	-----
	24-hr	7.8	11	18.8	365	5.2	262	7.2
	Annual	0.8	3	3.8	80	4.8	52	7.3
Pb	Quarterly[d]	0.0005	Not. Avail.	0.0005	1.5	0.03		
	90-day[d]	0.0005	Not. Avail.	0.0005	-----	-----	1.5	0.03

[a] Concentrations are high-second high values except annual averages and SO_2 1-hr, which is high-6th-high.
[b] One-hour NOx impact is converted to NO_2 by applying the ozone limiting method, as per DEQ guidance.
[c] Annual NOx is converted to NO_2 by applying the ambient ratio method, as per DEQ guidance.
[d] SME reported the 24-hour average impact for compliance demonstration.
[e] PM_{10} modeling results are compared to $PM_{2.5}$ standards.

Cumulative impact modeling, including emissions from all PSD increment-consuming sources in the Great Falls area, was used to demonstrate compliance with the Class II PSD increments for PM_{10}, NO_x and SO_2. Class II increment modeling results are compared to the applicable PSD increments in Table 3.

Table 3: Class II PSD Increment Compliance Demonstration

Pollutant	Avg. Period	Met Data Set	Modeled Conc. ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)	% Class II Increment Consumed	Peak Impact Location (UTM Zone 12)
PM_{10}	24-hr	Great Falls 1988	10.5	30	35%	(497701, 5266846)
	Annual	Great Falls 1987	3.2	17	19%	(497701, 5267036)
SO_2	3-hr	Great Falls 1999	12.6	512	2.5%	(497069, 5266071)
	24-hr	Great Falls 2003	6.33	91	6.9%	(497069, 5266071)
	Annual	Great Falls 1987	0.4	20	2.0%	(497386, 5268078)
NO_2	Annual[b]	Great Falls 1988	1.7	25	6.8%	(497386, 5268078)

a – Compliance with short-term standards is based on high-second-high impact.
b – Annual NO_x impacts are compared to the NO_2 standards.

SME-HGS submitted CALPUFF modeling to determine concentration, visibility and deposition impacts at the Class I areas within 250 km of the project site. CALMET was used to prepare meteorological data for input to CALPUFF. Meteorological data inputs to CALMET are included in Table 4.

Table 4: CALPUFF MET Data

Input Data Parameter	Model Year		
	1990	1992	1996
Number of Surface Stations	14	13	13
Number of Upper Air Stations	7	7	5
Number of Precipitation Stations	98	99	92
MM4/MM5 Data Grid Size	80 km	80 km	36 km

SME-HGS modeled PM_{10}, SO_2, and NO_x emissions from the SME-HGS project, and compared SME-HGS impacts to EPA's proposed Class I SIL's. SME-HGS's impacts exceeded the Class I SO_2 SILs at the Gates of the Mountain and Scapegoat Wilderness Areas. Modeling of PM_{10} and NO_x emissions did not show any exceedances of the Class I SILs at any of the Class I areas. Cumulative impact modeling for SO_2, including all PSD increment-consuming sources, was provided for the Class I areas. Results of the Class I cumulative impact modeling are included in Table 5 and show that the cumulative modeled concentrations are lower than the Class I PSD increments.

Table 5: Class I PSD Increment Compliance Demonstration, Peak Impacts

Pollutant	Avg. Period	Met Data Period	SME Modeled Conc. ($\mu g/m^3$)	Non-SME Modeled Conc. ($\mu g/m^3$)	Total Modeled Conc. ($\mu g/m^3$)	% Class I Increment Consumed
Gates of the Mountains						
SO_2	3-hr	July 23, 1996	1.08	1.26	2.34	9.4%
	24-hr	March 5, 1996	0.25	0.29	0.54	11%
Scapegoat Wilderness Area						
SO_2	24-hr	April 11, 1990	0.21	0.36	0.57	11%

a – Compliance with short-term standards is based on high-first-high impact.

SME-HGS used the CALPUFF modeling results and the CALPOST program to determine deposition values in the Class I areas. The results are shown in Table 6 and are compared to the deposition level of concern identified in the Federal Land Managers Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000). None of the modeled deposition impacts exceeded the FLAG level of concern. The Department concluded that no additional analysis of deposition impacts is needed.

Table 6: SME-HGS CALPUFF Deposition Modeling Results

Class I Area	1990		1992		1996	
	N (kg/ha/yr)	S (kg/ha/yr)	N (kg/ha/yr)	S (kg/ha/yr)	N (kg/ha/yr)	S (kg/ha/yr)
Ana-Pintler	0.0003	0.0004	0.0001	0.0002	0.0002	0.0002
Bob Marsh.	0.001	0.001	0.001	0.001	0.001	0.001
Gates Mtns.	0.002	0.002	0.002	0.002	0.002	0.003
Glacier NP	0.0003	0.0003	0.0003	0.0003	0.001	0.001
Mission Mtns	0.0002	0.0003	0.0005	0.001	0.0004	0.001
Scapegoat	0.001	0.001	0.001	0.001	0.002	0.002
UL Bend	0.002	0.002	0.001	0.002	0.002	0.002
FLAG Level of Concern	0.005	0.005	0.005	0.005	0.005	0.005

SME-HGS provided an analysis of the impact of the proposed project on air quality related values (AQRV) in the Class I and Class II areas. The effects of deposition on sensitive plant species and the effects of trace elements deposition on soils, plants, and animals were found to be below guideline levels contained in the USEPA screening guideline (EPA 450/2-81-078). The Department and affected FLMs have concluded that lake acidification analyses were not necessary because there are no sensitive lakes in the project impact area.

A visibility impact assessment is required under ARM 17.8.825 and ARM 17.8.1103, which states that the visibility requirements are applicable to the owner or operator of a proposed major stationary source, as defined by ARM 17.8.802(22). ARM 17.8.1106(1) requires that "the owner or operator of a major stationary source "…demonstrate that the actual emissions (including fugitive emissions) will not cause or contribute to adverse impact on visibility within any federal Class I area or the Department shall not issue a permit."

SME-HGS provided a visibility impact assessment as required under ARM 17.8.825 and ARM 17.8.1103 using the CALPUFF/CALPOST modeling system. CALPOST compares visibility impacts from the modeled source(s) to pre-existing visual range at the affected Class I areas and calculates a percent reduction in background extinction ($\%\Delta B_{ext}$). The results of SME-HGS's final visibility analysis are included in Table 7 and show 6 days in which the modeled $\%\Delta B_{ext}$ values from SME were $\geq$ 5%. Cumulative impact modeling was performed for those days to determine the $\%\Delta B_{ext}$ value from all the existing permitted PSD increment-consuming sources that could contribute to visibility reduction. The modeling showed four days with cumulative modeled $\%\Delta B_{ext}$ value greater than 10%.

Table 7: SME Final Visibility Results (Refined Methodology)

Class I Area	Met Data Year	Max. ΔB_{ext} 24-hr Average	Number of Days $\%\Delta B_{ext} \geq 5.0\%$	Peak Cumulative $\%\Delta B_{ext}$
Bob Marshall Wilderness Area	1990	1.57	0	NA
	1992	6.90	1	14.45
	1996	9.92	2	19.21
Gates of the Mountains Wilderness Area	1990	5.62	1	5.63
	1992	4.32	0	NA
	1996	5.77	1	15.05
Glacier National Park	1992	3.92	0	NA
	1996	1.21	0	NA
Scapegoat Wilderness Area	1990	2.31	0	NA
	1992	4.30	0	NA
	1996	5.31	1	13.65
UL Bend Wilderness Area	1992	2.09	0	NA
	1996	4.47	0	NA

The Department reviewed the visibility analysis and determined that the SME-HGS project alone and the cumulative impact of all permitted PSD increment-consuming sources will not cause or contribute to an adverse impact on visibility. The proposed emissions will not result in visibility impairment which the Department determines does, or is likely to, interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within the affected federal Class I area. This determination takes into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of the federal Class I area, and the frequency and occurrence of natural conditions that reduce visibility.

Conclusion

The preceding analysis represents a summary of predicted ambient air quality impacts resulting from the proposed SME-HGS project. A comprehensive and complete dispersion modeling analysis demonstrating compliance with all applicable increments and standards is on file with the Department. Based on this analysis, the Department determined that the proposed project operating in compliance with the applicable requirements contained in Permit #3423-00 is expected to maintain compliance with all applicable increments and standards as required for permit issuance.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VIII. Environmental Assessment

The proposed SME-HGS project was subject to review under the requirements of the Montana Environmental Policy Act. A comprehensive Final Environmental Impact Statement (FEIS) was issued on February 9, 2007, and the Record of Decision on the FEIS was published on April 20, 2007 A copy of the FEIS is available from the Department upon request.

Permit Analysis Prepared By: M. Eric Merchant, MPH
Date: March 27, 2007

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November 1, 2007

Roderick L. Bremby
Secretary, Kansas Department of Health
and Environment
Curtis State Office Building
1000 S.W. Jackson Street, Suite 540
Topeka, Kansas 66612-1368

Re: KDHE Denial of Sunflower Electric Power Corporation's Application for PSD Construction Permit
Our File No. 16895-215

Dear Secretary Bremby:

Enclosed and hereby served upon you is Petitioner's Petition For Reconsideration Of Denial Of Permit Application Under K.S.A. § 65-3008a(b) relating to the above-referenced matter.

Very truly yours,

W.C. Blanton

WCB/amm
Enclosure

Cc: Yvonne Anderson, General Counsel, KDHE

KC-1546414-1

BEFORE THE
KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT

IN THE MATTER OF:	)	
	)	
APPLICATION OF SUNFLOWER	)	**Case No. _____**
ELECTRIC POWER CORPORATION	)	
FOR ISSUANCE OF PSD	)	
CONSTRUCTION PERMIT	)	
	)	

PETITION FOR RECONSIDERATION OF DENIAL
OF PERMIT APPLICATION UNDER K.S.A. § 65-3008a(b)

Sunflower Electric Power Corporation ("Sunflower") hereby petitions the Kansas Department of Health and Environment ("KDHE") pursuant to K.S.A. § 77-529 to reconsider the denial of Sunflower's application for the issuance of a permit authorizing construction of two new electricity generating units (the "Power Plants") at Sunflower's Holcomb Generating Station located in Finney County, Kansas by KDHE Secretary Roderick L. Bremby (the "Secretary") on October 18, 2007 (the "Denial Order"), to the extent (1) that the Denial Order was issued pursuant to K.S.A. § 65-3008a(b), and (2) that the Denial Order is a "final order" for the purposes of K.S.A. § 77-529. It is Sunflower's contention that the Denial Order is not a "final order" within the meaning of that term for the purposes of K.S.A. § 77-529. However, in any event, this petition by Sunflower for reconsideration of the Denial Order is hereby properly and timely made pursuant to K.S.A. § 65-3008b(e), K.S.A. § 77-529, and the terms of the Denial Order, so as to preserve Sunflower's rights with respect to all current and any future challenges to the Denial Order. A copy of the Denial Order is attached as Exhibit A. In support of this request, Sunflower states:

1. In February 2006, Sunflower applied to KDHE for the issuance of a permit that would authorize construction of the Power Plants (the "Application").

2. On October 18, 2007, the Secretary denied Sunflower's Application, stating that he has "authority under K.S.A. § 65-3012 ... to take such action as is necessary to protect the health of persons or the environment, notwithstanding a permit applicant's compliance with all other existing provisions of the Kansas air quality act" and that in his opinion, there was "support for the position that emission of air pollution from the proposed coal fired plant, specifically carbon dioxide emission, presents a substantial endangerment to the health of persons or to the environment."

3. Sunflower's grounds for seeking reconsideration of the Denial Order are as follows:

A. The Denial Order is invalid because the Secretary has erroneously interpreted or applied Section 3012, in that K.S.A. § 65-3012 ("Section 3012") only addresses current air pollution that results from existing stationary and mobile sources of air contaminant emissions and thus provides no authority to the Secretary to deny a permit to construct a new source of such emissions.

B. The Denial Order is invalid because in issuing the Denial Order on the basis of Section 3012, the Secretary has acted beyond the jurisdiction conferred upon KDHE by any provision of law, in that the Secretary has no delegated authority to rely on Section 3012 to deny Sunflower's Application.

C. The Denial Order is invalid because the Secretary has engaged in an unlawful procedure, in that the Secretary's reliance on Section 3012 to deny Sunflower's Application constitutes de facto rulemaking without compliance with proper rulemaking procedures.

D. The Denial Order is invalid because (a) the Secretary has engaged in an unlawful procedure and decision making, and (b) the Secretary's issuance of the Denial Order is unconstitutional, in that it denied Sunflower its procedural due process rights under the United States and Kansas constitutions, as follows:

1. The Secretary failed to provide Sunflower any notice of his intent to consider Section 3012 in taking final action on Sunflower's Application.

2. The Secretary failed to provide Sunflower any opportunity to be heard concerning his consideration of Section 3012 in taking final action on Sunflower's Application.

3. The Secretary failed to provide Sunflower any notice of any decisional standard or criteria that Sunflower must satisfy to obtain the permit sought or any notice of the process by which the Secretary would consider Section 3012 in taking final action on Sunflower's Application; nor has the Secretary at any time articulated any such decisional standard, criteria or process.

4. The Secretary failed to support the Denial Order with findings of fact or to relate his "findings" to decision making criteria that are objective, ascertainable, and applied consistently and uniformly.

5. The Secretary failed to provide Sunflower any opportunity to respond to the Denial Order prior to it becoming effective.

E. The Denial Order is invalid because the Secretary's issuance of the Denial Order is unconstitutional, in that it prohibits the potential emissions of carbon dioxide from the proposed Power Plants without equally applying such a restriction upon either long-existing or newly permitted sources and thereby denies Sunflower's right to equal protection under the law under the United States and Kansas Constitutions.

F. The Denial Order is invalid because the Secretary's issuance of the Denial Order is unconstitutional, in that it unlawfully interferes with and places an undue burden upon interstate commerce in contravention of the Commerce Clause of the United States Constitution.

G. The Denial Order is invalid because it is based upon purported determinations of fact that are not supported by evidence that is substantial when viewed in light of the record as a whole, in that the Denial Order contains no factual determination that emissions of carbon dioxide from the proposed Power Plants will cause a substantial endangerment to the health of persons or to the environment; and there is no substantial evidence in the record to support such a factual determination.

H. For each and all of the foregoing reasons, the Denial Order is invalid because its issuance was unreasonable, arbitrary, capricious, and contrary to law.

Dated: November 1, 2007

Respectfully submitted,

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ATTORNEYS FOR APPLICANT, SUNFLOWER ELECTRIC POWER CORPORATION

EXHIBIT A

K A N S A S

RODERICK L. BREMBY, SECRETARY

KATHLEEN SEBELIUS, GOVERNOR

DEPARTMENT OF HEALTH AND ENVIRONMENT

October 18, 2007

Sunflower Electric Power Corporation
Mr. Wayne Penrod
Senior Manager
301 W. 13th
Hays, KS 67601

Dear Mr. Penrod:

It is my duty as Secretary of the Kansas Department of Health and Environment, as authorized by the Kansas air quality act, K.S.A. 65-3001 et seq. to protect the public health and environment from actual, threatened or potential harm from air pollution.

The secretary has broad authority under the act and the regulations adopted thereunder to achieve protection of the health of the people and the environment. . The secretary has authority under K.S.A. 65-3008a(b) to affirm, modify or reverse a decision on an air quality permit after the public comment period or public hearing. The secretary also has authority under K.S.A. 65-3012 as interpreted by the Attorney General of the state of Kansas, to take such action as is necessary to protect the health of persons or the environment, notwithstanding a permit applicant's compliance with all other existing provisions of the Kansas air quality act, upon receipt of information that the emission of air pollution presents a substantial endangerment to the health of person or the environment. The endangerment may be a threatened or potential harm as well as an actual harm.

The Supreme Court of the United States found in Massachusetts v. E.P.A., 127 S.Ct. 1438 (April 2, 2007) that carbon dioxide, a greenhouse gas, meets the broad definition of air pollutant under the Clean Air Act. The Kansas air quality act similarly has a broad definition of what constitutes air pollution. The Court also recognized the significant existing national and international information available on the deleterious impact of greenhouse gases on the environment in which we live.

I have given due consideration to the scientific and technical information related to carbon dioxide including but not limited to many oral and written comments submitted in the public hearing and comment period. The information provides support for the position that emission of air pollution from the proposed coal fired plant, specifically

OFFICE OF THE SECRETARY
CURTIS STATE OFFICE BUILDING, 1000 SW JACKSON ST., STE. 540, TOPEKA, KS 66612-1368
Voice 785-296-0461 Fax 785-368-6368 http://www.kdhe.state.ks.us

EXHIBIT

A

carbon dioxide emissions, presents a substantial endangerment to the health of persons or to the environment.

Based on this information, the permit is denied. Pursuant to K.S.A. 65-3008b(e),the permit applicant has the right to appeal this decision within fifteen (15) days and request an administrative hearing under the Kansas administrative procedures act set forth at K.S.A. 77-501 *et seq.*

Sincerely,

Roderick L. Bremby
Secretary

CERTIFICATE OF SERVICE

Copies of the foregoing **Petition For Reconsideration Of Denial Of Permit Application Under K.S.A. § 65-3008a(b)** have been served via United States mail, facsimile, e-mail, and hand-delivery this 1st day of November, 2007, upon:

Roderick L. Bremby
Secretary, Kansas Department of Health and Environment
Curtis State Office Building
1000 S.W. Jackson Street, Suite 540
Topeka, Kansas 66612-1368
Facsimile: (785) 368-6368

Yvonne C. Anderson
General Counsel
Kansas Department of Health and Environment
Curtis State Office Building
1000 S.W. Jackson, Suite 560
Topeka, KS 66612

W. C. Blanton
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4801 Main Street, Suite 1000
Kansas City, Missouri 64112

STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENTAL QUALITY
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

STEVEN E. CHESTER
DIRECTOR

December 20, 2007

Dear Interested Party:

Thank you for your interest regarding the Michigan Department of Environmental Quality's (MDEQ) concept of including Integrated Gasification Combined Cycle (IGCC) in Best Available Control Technology (BACT) reviews for new coal-fired electric generating facilities.

At this time, the MDEQ has concluded that the consideration of clean coal technology, specifically requiring IGCC, in a BACT review will be considered on a case-by-case basis within the context of an air use permit to install application.

If you have any questions, please contact Mr. G. Vinson Hellwig, Chief, Air Quality Division, at 517-373-7069, or you may contact me.

Sincerely,

Steven E. Chester
Director
517-373-7917

cc: Mr. Jim Sygo, Deputy Director, MDEQ
Mr. G. Vinson Hellwig, MDEQ

Prevention of Significant Air Quality Deterioration Review
Of the Longleaf Energy Associates, LLC
Longleaf Energy Station
To be located in Early County, Georgia

FINAL DETERMINATION
SIP Permit Application No. 15846
May 2007

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program (SSPP)	Planning & Support Program
Prepared by	
Anna C. Aponte – NOx Unit	Peter Courtney – Data & Modeling Unit
Reviewed and Approved by:	
Michelle Keith – NOx Unit Coordinator James Capp – SSPP Manager	James Boylan – Unit Coordinator, Data & Modeling Unit
Heather Abrams – Chief, Air Protection Branch	

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Background

On November 22, 2004, (updated July 12, 2005 and August 15, 2005) Longleaf Energy Associates, LLC submitted an application for an air quality permit to construct and operate a pulverized coal-fired electric power generation facility at a site to be called the Longleaf Energy Station in Hilton, Georgia (Early County). The facility will consist of two units, each one comprised of one pulverized coal (PC) fired boiler, a multiple shell condensing steam turbine generator, multiple steam surface condensers and a multiple cell mechanical draft-cooling tower. The facility is designed to burn Powder River Basin (PRB) coal and/or Central Appalachian coal (CAPP).

On September 15, 2006, EPD issued a Preliminary Determination stating that the construction and operation of the pulverized coal-fired electric power generation facility should be approved. The Preliminary Determination contained a draft Air Quality Permit for the construction and operation of the pulverized coal-fired electric power generation facility.

The Division requested that Longleaf Energy Associates, LLC place a public notice in a newspaper of general circulation in the area of the proposed facility notifying the public of the proposed construction and providing the opportunity for written public comment and public hearing. Such public notice was placed in *Early County News* (legal organ for Early County) and *The Dothan* Eagle (legal organ for Houston County, Alabama) on September 20, 2006. Georgia EPD held a Question & Answer session on October 17, 2006 and a public hearing on November 9, 2006. The public comment period expired November 16, 2006.

During the comment period, comments were received from Longleaf Energy Associates, LLC, the U.S. EPA, United States Department of the Interior – Fish and Wildlife Service, The Georgia Center for Law in the Public Interest, Southern Environmental Law Center, Southern Alliance for Clean Energy, and hundreds of emails and letters from citizens of Georgia, Alabama and Florida. This discussion will not elaborate on typographical or grammatical revisions made to the final permit. The comments are listed below along with the Division's responses and a discussion of any changes made to the final Permit. A copy of the final permit is provided in Appendix A. A copy of comments received during the public comment period is provided in Appendix B. A copy of additional correspondence received is provided in Appendix C.

Comments from US E.P.A

1. PC Boiler Design

On pages 198 and 199 of the preliminary determination, you describe the PC boilers as being supercritical units. The description section of the draft permit, however, is less clear about the design in that the boilers are simply described as "two coal (PC) fired boilers." We strongly recommend that the final permit contain a requirement that the PC boilers be designed and installed as supercritical boilers. We further recommend that Longleaf Energy be required to provide contractual design information as soon as a boiler supplier is selected and prior to start of construction on the boiler structure itself. Our recommendations about supercritical design are based in part on the fact that the primary emissions limits in the draft permit are on the basis of pounds per million Btu heat input. (See further discussion below.) Supercritical design will produce lower total emissions than subcritical design because not as much heat input is required to produce the same amount of energy output.

Response: EPD prepared a draft permit and preliminary determination based on the option of using subcritical or supercritical units at the facility. BACT was proposed for the facility without distinguishing between those options. In addition, it is not certain, that emissions would be lower using supercritical-designed boilers. The air quality impact analyses are based upon the emission estimates contained in the LEA November 19, 2004 PSD application (the "Application") and supplemental information. These emissions estimates are based on a heat input to each boiler of 6,139 MMBtu/hr and they were modeled and evaluated by EPD to ensure the air quality of the region will be fully protected.

2. Expression of Emissions Limits

a. For the most part, emissions limits for the PC boilers are specified in terms of lb/MMBtu. However, the draft permit does not include a limit on maximum short-term heat input (MMBtu/hr). A limit solely in terms of lb/MMBtu does not establish an upper limit on hourly emissions unless accompanied by a limit on short-term maximum heat input or total mass emissions (e.g., lb/hr). Therefore, the draft permit does not contain specific emissions limits that match the total mass emissions rates used for ambient impact modeling purposes. The final permit, if issued, should contain either (a) enforceable limits for maximum short-term heat input (MMBtu/hr) as well as enforceable limits in terms of lb/MMBtu, or (b) enforceable limits in terms of lb/MMBtu and enforceable limits in terms of lb/hr.

Response: Longleaf Energy has proposed building two PC-fuel fired boilers each having a design heat input of 6,139 MMBtu/hr. EPD will include that number in the final permit as an enforceable requirement.

b. The shortest compliance averaging period in the draft period for SO_2 is a 24-hour averaging period. In general, permit compliance averaging periods should match the averaging periods used in ambient impact modeling evaluations. Since modeling was performed for SO_2 to demonstrate compliance with the 3-hour NAAQS and PSD increments, the permit should also contain a 3-hour SO_2 emissions limit in addition to, or in lieu of, a 24-hour emissions limit. As an alternative you could provide an analysis demonstrating that the proposed maximum 24-hour SO_2 emissions limit of 0.12 lb/MMBtu can not produce higher 3-hour ambient concentrations than the 3-hour SO_2 emissions rate of 0.26 lb/MMBtu used by the applicant to model 3-hour concentrations.

Response: There is no requirement for BACT limits to have averaging times equal to, or less than, the shortest NAAQS or PSD increment averaging time for a given pollutant. EPD believes that the BACT limits are protective of the NAAQS and PSD increments and EPA presented no evidence to the contrary.

c. For three pollutants (fluorine, mercury, and hydrochloric acid), the draft permit contains one limit for PRB coal combustion and one limit for CAPP coal combustion. This implies that the source owner will not be allowed to burn a blend of PRB and CAPP coals. If your intent is to disallow combustion of coal blends, this should be so stated in the permit. If you intend to allow combustion of coal blends, then you need to provide emissions limits for blends for these pollutants.

Response: EPD will modify the permit to make it clear that coal blending is allowed and that the emission limits for fluorine, mercury, and hydrochloric acid are based upon a weighted average of the individual limits according to the heat input provided by each of the fuels.

3. <u>BACT Cost Evaluations</u>

a. You provide PC boiler BACT cost evaluations in several tables within the preliminary determination (Tables IX, XI, XIV, XVII, XIX, XXI, XXIII, XXVI, XXIX, and XXXII). In each case you state that the costs are determined for a 600 MW (net) unit with an 85 percent capacity factor. Our general guidance is that permit conditions should reflect the basis of BACT determinations. In line with this guidance, we do not see any provisions in the draft permit that (a) restrict each boiler to a generating rate no greater than 85 percent of capacity on an annual basis, or (b) limit annual emissions to those used as the basis of the BACT cost assessments. We recommend that you either add such conditions to the permit or check to make sure that the BACT determinations would not change if maximum allowable emissions were used as the basis of the BACT cost assessments.

Response: EPA's comment specifically contradicts their own national guidance in the NSR Workshop Manual, which clearly states that cost evaluations may use reasonable assumptions on maximum expected operations. However, even if 100% capacity were used in the cost evaluations we no not believe any of the BACT conclusions would be different.

b. In Tables IX, XI, XIV, XXIII, and XXVI within the preliminary determination, you provide both total cost effectiveness values (dollars per ton removed) and incremental cost effectiveness values. EPA's general policy is that reviewing authorities should not rely on incremental costs as a primary determinant when making BACT determinations. To the extent that incremental cost effectiveness values have played a key role in any of your BACT determinations, we request that you reconsider these determinations. For example, in Table XI (page 51) for SO_2, you list the wet scrubber option with a total cost effectiveness value of $761 and an incremental cost effectiveness value (compared to the dry scrubber option) of $12,674. You then state on page 52 of the preliminary determination that the wet scrubbing option is rejected in part on the basis of "excessive economic impacts." We consider a total cost effectiveness value of $761 to be a reasonable cost for SO_2 control. If the incremental cost effectiveness value was a key determinant in your rejection of wet scrubbing, we request that you re-evaluate this option.

Response: In determining BACT, EPD considered energy, environmental, and economic (both average and incremental cost) impacts. EPD did not focus solely on incremental costs as suggested by the comment.

4. <u>General Comment on BACT Determinations for PC Boilers</u>

The public record in support of your BACT determinations for the PC boilers would be strengthened by having an actual list of the specific project precedents on which you relied. For example, on page 69 of the preliminary determination related to your PM BACT determination you refer to the "most common limit for PM/PM_{10} emissions," but do you did not list the specific project limits on which you based this statement.

Response: A non-exclusive list of specific projects that were reviewed by EPD at has been included in the final determination in Appendix E. The list includes every project mentioned by EPA in their written comments along with a number of other projects.

5. BACT for Nitrogen Oxides Emissions from PC Boilers

a. The NO_x BACT emissions limit in the draft permit is 0.07 lb/MMBtu (30-day average). Consistent with our initial comments on the Longleaf Energy permit application, we maintain the opinion that the NO_x emissions limit for a well-designed new PC boiler should be lower. As a possible alternative to a lower 30-day limit, you could consider adding a 12-month limit to the 30-day limit.

b. In support of our opinion, we first repeat what we said in our initial comments. In these comments we cited as an example a proposed new PC EUSGU at the Louisville Gas & Electric Trimble County station. (The proposed EUSGU will be capable of burning bituminous coal or a blend of bituminous and subbituminous coals.) The NO_x emissions limits for this project are equivalent to 0.05 lb/MMBtu on a 24-hour basis. Although LG&E=s proposed NO_x limit is for PSD avoidance purposes, it is still a valid point of comparison. We also cited for comparison existing facilities such as Georgia Power=s Plant Bowen that have been retrofitted with NO_x controls and that routinely are achieving NO_x emissions below 0.07 lb/MMBtu. Similar examples of existing operating facilities with NO_x emissions less than 0.07 lb/MMBtu can be found in EPA's Clean Air Markets Division database. Although many of these existing units only operate with SCR controls part of the year, we still believe they are valid for comparison because they are generally old facilities that have been retrofitted with SCR. We would expect a new, well-designed unit to be able to achieve year-round emissions comparable to those achieved by retrofitted older units with partial-year SCR emissions controls.

c. In further support of our opinion, we cite first a recent draft PSD permit issued for the proposed Sithe Global Power Desert Rock low-sulfur subbituminous PC EUSGU project in New Mexico. The NO_x emissions limit in the draft permit is 0.06 lb/MMBtu (24-hour average). (The permit also contains lb/hr limits on a 3-hour and annual basis.) We also cite seven recently issue draft permits for proposed TXU low-sulfur subbituminous EUSGU's in Texas (Big Brown Unit 3, Lake Creek Unit 3, Martin Lake Unit 4, Monticello Unit 4, Morgan Creek Unit 7, Tradinghouse Unit 3 and Unit 4, and Valley Unit 4. In each of these draft permits the proposed NO_x emissions limits are 0.07 lb/MMBtu on a 30-day rolling basis and 0.05 lb/MMBtu on a 12-month rolling basis.

Response: EPD has added a NOx limit of 0.05 lb/MMBtu on a 12-month rolling basis. To allow for uncertainties in meeting such a stringent limit immediately upon startup, this limit shall take effect 6 months after initial startup of each boiler.

6. BACT for Particulate Matter Emissions from PC Boilers

The proposed BACT filterable PM emissions limit for the Longleaf Energy PC boilers is 0.015 lb/MMBtu. By comparison, draft permits have recently been issued for two proposed low-sulfur subbituminous PC EUSGU projects with lower filterable PM limits than the proposed Longleaf Energy limit. In a draft permit for the Sithe Global Power Desert Rock project in New Mexico, the proposed filterable PM limit is 0.010 lb/MMBtu (24-hour average). (The draft permit also contains a total PM limit of 0.020 lb/MMBtu (24-hour average), as well as lb/hr limits (6-hour average) for filterable and total PM.) In a draft permit for the Sunflower Electric Holcomb project in Kansas, the proposed filterable PM limit is 0.012 lb/MMBtu. (The draft permit also contains a total PM limit of 0.035 lb/MMBtu.) As an additional comparison point, a draft PSD permit recently issued for a proposed new PC EUSGU at the Seminole Electric Cooperative Palatka generating station in Florida contains a filterable PM emissions limit of 0.013 lb/MMBtu. The proposed unit is a supercritical boiler that will burn bituminous coal. The proposed PM control methods consist of a dry ESP and a wet ESP (the latter primarily for sulfuric acid mist control). We would expect that a project like the Longleaf Energy project that is based on combustion of western low-sulfur subbituminous coal as the primary fuel and that will be equipped with a baghouse for PM control should be able to achieve a filterable PM emissions limit comparable to those proposed for Sithe Global Energy Desert Rock and Sunflower Electric Holcomb, and at least as stringent as the proposed limit for Seminole Electric Cooperative Palatka.

Response: EPA mentions three projects with slightly lower PM limits than the PM limits in the draft Longleaf Energy permit. It should be noted that one of the projects cited by EPA (Sunflower) actually has a higher emission limit for total particulate matter than Longleaf. And, another project (Seminole) cited by EPA has no limit at all for total particulate matter. EPA provides no explanation for these facts. In addition, EPA does not mention that most of the coal-fired projects (as demonstrated in the attached table of coal-fired projects and emission limits) in the country have higher PM limits than the draft Longleaf Energy permit. Nonetheless, EPD does believe that a slightly lower level of emissions for filterable PM emissions should be achievable from the facility. Therefore, the filterable PM limit has been reduced from 0.015 lb/MMBtu to 0.012 lb/MMBtu. This change also causes a commensurate reduction in the total PM limit from 0.033 lb/MMBtu to 0.030 lb/MMBtu.

7. BACT for Carbon Monoxide Emissions from PC Boilers

The proposed CO emissions limits are 0.15 lb/MMBtu (30-day average) and 0.30 lb/MMBtu (1-hour average). For your consideration, the recently issued permit for the Sithe Global Power Desert Rock project in New Mexico contains a CO emissions limit of 0.10 lb/MMBtu (24-hour average). (The permit also contains lb/hr limits on a 3-hour and annual basis.)

Response: EPA mentions one unpermitted coal-fired project in its comment. Most coal-fired projects (as demonstrated in the attached table of coal-fired projects and emission limits) have proposed BACT limits that are the same, or very close to the same, as the draft Longleaf Energy permit. EPD continues to believe that the BACT limits for CO in the draft Longleaf Energy permit meet the requirements of BACT. No changes have been made to the permit based on this comment. EPD also notes the important relationship between CO emissions and NOx emissions. As CO emissions are further reduced, NOx emissions tend to increase. From both a health standpoint as well as a visibility standpoint, it is more important to reduce NOx emissions than CO emissions. As noted above regarding EPA's comments on the NOx BACT level, these NOx limits have been made even more stringent.

8. BACT for Sulfuric Acid Mist Emissions from PC Boilers

The proposed sulfuric acid mist emissions limit is 0.005 lb/MMBtu (3-hour average). For your consideration, the recently issued permit for the Sithe Global Power Desert Rock project in New Mexico contains a sulfuric acid mist emissions limit of 0.004 lb/MMBtu (3-hour average).

Response: EPA mentions one unpermitted coal-fired project in its comment. Most coal-fired projects (as demonstrated in the attached table of coal-fired projects and emission limits) have proposed BACT limits that are the same, or very close to the same, as the draft Longleaf Energy permit. EPD continues to believe that the BACT limit for Sulfuric Acid Mist in the draft Longleaf Energy permit meets the requirements of BACT. No changes have been made to the permit based on this comment.

9. Cooling Tower Emissions

a. On page 169 of the preliminary determination, you state that the cooling towers will be equipped with high efficiency drift eliminators that "should keep drift to 0.001% of flow." A drift rate of 0.001 percent is not as efficient as required by some other recent coal-fired EUSGU permits. For example, the recently issued draft permit for the Seminole Electric Cooperative Palatka Unit 3 project in Florida mandates a drift rate of 0.0005 percent. Reducing the allowed drift rate by half would decrease the estimated cooling tower PM and PM_{10} emissions from approximately 50 tpy and 9 tpy respectively to approximately 25 and 4 tpy respectively

b. The draft permit does not contain any restrictions on cooling tower emissions. If you issue a final permit, it should contain a mandatory drift rate design value that we recommend be no higher than 0.0005 percent.

Response: Longleaf Energy is proposing to use recycled wastewater from the Georgia-Pacific paper mill to supply make-up water to the cooling tower. Because this recycled wastewater has a high organic content, cooling tower manufacturers have informed the company that the best drift eliminator technically feasible is 0.001%. Therefore, the 0.0005% drift elimination rate cited by other sources is not directly comparable to the Facility nor is it technically feasible based on the water supply available to Longleaf Energy. EPD has added to the final permit a requirement that drift eliminators of 0.001% or better be used on the Facility cooling towers.

10. Fine Particles

$PM_{2.5}$ is a regulated NSR pollutant and should be acknowledged as such in the final determination. At your discretion, you could state that you are following EPA's guidance to use PM_{10} as a surrogate for $PM_{2.5}$ until final $PM_{2.5}$ NSR implementation rules are adopted.

Response: EPD is following EPA's guidance to use PM_{10} as a surrogate for $PM_{2.5}$ until final $PM_{2.5}$ NSR implementation rules are adopted.

11. Startup and Shutdown of PC Boilers

a. Startup and shutdown are part of normal source operation for the PC boilers. Any pollutants emitted from these boilers during startup and shutdown that are subject to PSD review are therefore subject to best available control technology (BACT) requirements. We understand that the numeric BACT emissions limits for regular operation are applicable during startup and shutdown. You could also consider adding work practice requirements for startups and shutdowns. Such work practice requirements could include permit restrictions on the duration of individual startup events, permit restrictions on the number of startup/shutdown events in an annual period, and/or an itemization of the specific procedures for Longleaf Energy that are discussed on pages 20 and 21 of your preliminary determination.

Response: The BACT limits in the permit apply at all times, including startup and shutdown. Georgia Rule 391-3-1-.02(2)(a)7(i) provides that excess emissions during startup and shutdown "shall be allowed" provided that certain criteria are met (1. the best operational practices to minimize emissions are adhered to, and 2. all associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions and 3. the duration of excess emissions is minimized. No changes are made to the permit based on this comment.

b. The first sentence of the last paragraph on page 21 is incomplete. (This sentence begins "Therefore, since the Longleaf Energy ....")

Response: This was just a typographical error. The period at the end of the first sentence should have been a comma.

12. IGCC Discussion

Starting on page 194 of the preliminary determination, you provide a discussion of IGCC technology. On page 198 within this discussion, you comment that "EPA's view is that applying the IGCC technology would fundamentally change the scope of the project and redefine the basic design of the proposed source." Furthermore, in footnote 5 on page 9, you comment that EPA has said "other means of coal-fired power generation do not have to be evaluated as part of a BACT analysis." For clarification, please note that EPA has not issued any guidance on this point that should be considered final agency action binding on a state reviewing authority.

Response: EPD realizes that EPA has not taken final agency action on this issue that is binding on a state reviewing authority. EPD never stated, or implied, that this was the case. EPA has issued nonbinding guidance on this issue. EPD addressed this guidance in the preliminary determination. EPA has never rescinded that guidance, however, they have clarified that it is just guidance. As a SIP approved program, EPD notes that all EPA guidance is nonbinding.

13. Miscellaneous

a. Longleaf Energy states in its permit application that heat input to the PC boilers from combustion of clairifier sludge will be less than 1 percent of total heat input. We recommend that a permit condition be added to this effect.

Response: EPD has added to the final permit a condition requiring that clarifier sludge combustion be limited to less than 1 percent of the potential total heat input (clarifier heat input of 614 MMBtu/hr).

b. On pages 27 through 29 of the preliminary determination you make reference to SCONOx™ technology as a NO_x control option and deem it to be technically infeasible. SCONOx™ has been replaced by a next-generation technology called EMx™ that is marketed by EmeraChem. Please assess whether EMx™ technology is also technically infeasible for this project.

Response: According to the manufacturer of EM_x^{TM} it cannot be used on coal-fired generating facilities because of corrosion issues. The technology is only designed for natural gas-fired generating facilities.

14. Specific Permit Conditions

a. Condition 2.10 - (a) In this condition you allow blending of pet coke with primary fuels. We recommend that you specify the maximum weight percentage of pet coke that can be burned simultaneously with primary fuels. (b) In this condition (and some others as well), you use the term "PRB coal." The Powder River Basin is a specific geographic area. Do you literally mean to restrict combustion of subbituminous coal to coal from the Powder River Basin only, or do you mean subbituminous coal from the western U.S. in general?

Response: The blending of pet coke is effectively limited by the 3% sulfur limit on fuel burned and the stringent BACT SO_2 limits imposed by the permit. No changes are made to the permit based on this comment.

b. Condition 2.14.a - Within the bracketed comment at the end of this condition, you indicate that the applicable NSPS is "subsumed" by the permitted NO_x emissions limit. We understand that this means compliance with the permitted limit of 0.07 lb/MMBtu will assure compliance with the NSPS of 1.0 lb/MWh. [Please change the cited NSPS from "40 CFR 60.44a(e)(1)" to "40 CFR 60.44Da(e)(1)."]

Response: The regulatory citation has been changed in the final permit as requested in the comment.

c. Condition 2.14.c - Although we understand your assumption that all emissions from the PC boilers are PM_{10}, we recommend for clarity that you express the filterable PM emissions limit of 0.015 lb/MMBtu as a limit for PM/PM_{10} and not just for PM.

Response: EPD believes the permit is fine as currently written with respect to the particulate matter emission limits. The methods for verifying compliance with the emissions limits are clearly defined and comply with all requirements.

d. Condition 2.14.d, e, f, g - Within the bracketed comment at the end of these conditions, you indicate that the applicable NSPS is "subsumed" by the permitted SO_2 emissions limits. We understand that this means compliance with the permitted limits will assure compliance with the NSPS of 1.4 lb/MWh (30-day average). [Please change the cited NSPS from "40 CFR 60.43a(i)" to "40 CFR 60.43Da(i)(1)(i)."]

Response: The regulatory citation has been changed in the final permit as requested in the comment.

e. Condition 2.14.j - We recommend that the pollutant be expressed as "fluorides" rather than "fluorine."

Response: The expression of the pollutant regulatory citation has been changed in the final permit as requested in the comment.

f. Condition 2.14.l - This condition contains an annualized mercury limit "while firing PRB coal" and an annualized mercury limit "while firing CAPP coal." We recommend adding a provision to this condition stating that compliance with these annualized emissions limits includes any contribution to mercury emissions from the combustion of supplemental fuels such as clarifier sludge and pet coke. Without such a provision, the permit would not contain a limit on total mercury emissions from the PC boilers.

Response: The final permit has been modified to make it clear that the mercury limits are inclusive of the clarifier sludge.

g. Condition 2.14.m - When coupled with the opening language of Condition 2.14 ("shall not discharge ... from <u>each</u> PC-fired Boiler" [emphasis added]), Condition 2.14.m would allow total emissions from clarifier sludge incineration of 6.4 kg (14.2 lb) per 24-hour period. This is not consistent with the provisions of 40 CFR 61.52(b) which allow mercury emissions from "sludge incineration plants" (meaning total emissions) of 3.2 kg (7.1 lb) per 24-hour period.

Response: The final permit has been modified to make it clear that the mercury emissions from sludge incineration are limited to 3.2 kg (7.1 lb) per 24-hour period.

h. Conditions 2.18 through 2.21 - These conditions apply to material handling areas (coal handling, lime management, etc.). None of these conditions includes an emissions rate limit (such as lb/hr or gr/dscf). We request that you review all non-fugitive material handling emissions points (especially those with a control device) and assess whether emissions rate limits are needed.

Response: The definition of BACT states that if the permitting authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. EPD has made such a determination in this particular case.

i. Conditions 4.2.i and 4.2.j - These conditions require performance tests "to verify compliance" with the mercury emissions limits in Condition 2.14.l. Since these limits are annual average limits, how can individual performance tests provide verification of compliance?

Response: EPA is correct. The limits are annual average limits. The performance tests would only be able to determine the average hourly rate of mercury emissions during the test. In addition, EPD notes that the emissions units will be equipped with CEMS for mercury, so the monitoring requirements in the permit will provide a reasonable assurance of compliance with the mercury limits. Therefore, the requirements to do mercury stack tests have been removed from the final permit.

j. Condition 8.3 - We recommend that the phrase "obtain a sample of each coal train" be changed to "obtain a sample from each coal shipment."

Response: This condition has been changed in the final permit as requested in the comment.

k. Condition 8.4.a - We recommend that this condition be changed to read "Monthly quantity (tons) of each type of coal burned."

Response: This condition has been changed in the final permit as requested in the comment.

l. Condition 8.4 - We recommend that a provision be added to read as follows: "Monthly quantity (tons) of pet coke burned."

Response: This condition has been changed in the final permit as requested in the comment.

15. Air Quality Modeling Comments

a. Site Boundary - The modeled site boundary appears to be the property boundary for Longleaf Energy. Confirmation is needed that a physical barrier to public access will exist coinciding with this property boundary. Confirmation is also needed that there are no through roads or other public accessible rights-of-ways through the property.

Response: The modeled boundary is shown in Figure 5.2 on page 5-3 of the Application. Longleaf Energy will be fencing the property boundary to create a physical barrier to public access. However, as shown in Figure 5.2, the modeling and the property boundary include a public road through a portion of the site. The site property along this road will be fenced, however as depicted in Figure 5.2 the road may not be closed.

b. Startup and Shutdown Operations - The purpose of the supplemental Class II modeling report was to address the increased 1-hour CO and 3-hour SO_2 emission rates. This report also accounted for the use of baghouse PM_{10} controls during startup. The original application had hourly SO_2 emissions of up to 1.65 lb/MMBtu (for 3 hours) and 3.20 lb/MMBtu for PM_{10} (Table 5.1). The supplemental modeling report should have included a similar emissions table for the revised startup emission rates used in the modeling.

Response: A revised Table 5.1 is shown below. Only the PM_{10} emissions for hours 1-5 are different from the table in the application and they are lower during startup.

	Emissions (lb/MMBtu) by Startup Process Hour Number										
	1-3	4	5	6	7	8	9	10	11	12-15	16
CO	0.04	0.05	0.06	0.07	0.09	0.15	0.15	0.15	0.15	0.15	0.15
NOx	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.3	0.25	0.09	0.07
SO2	0.01	0.16	0.29	0.49	0.80	1.65	1.65	1.65	1.25	0.12	0.12
PM10	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033
VOC	0.0015	0.0023	0.0030	0.0040	0.0056	0.01	0.01	0.01	0.01	0.01	0.0036
Pb	0	$1.1x10^{-6}$	$2.1x10^{-6}$	$3.5x10^{-6}$	$5.8x10^{-6}$	$1.2x10^{-5}$	$1.2x10^{-5}$	$1.2x10^{-5}$	$1.2x10^{-5}$	$1.2x10^{-5}$	$1.2x10^{-5}$

c. Emission Inventories - The following comments are associated with the emission inventories of other sources used in the full (cumulative) PSD increment and NAAQS compliance assessments:

- Only the Class II emission inventory of other sources is provided in Appendix G of the original application. The Class I emission inventory of other sources also should be provided.

Response: The Class I inventory of sources was included as part of the Class I report in the Application. The inventory starts on page 2-5 of Appendix M of the Class I report.

- All emission sources within the Class II significant impact area (SIA) should be included in the modeling. Sony Magnetic Products-Dothan, located within the SIA, was improperly eliminated based on the 20D procedure.

Response: EPD disagrees that the Sony Magnetic Products – Dothan facility was improperly eliminated as a result of the 20D procedure. The use of the 20D procedure, including how it was to be used for elimination of sources, was documented in a modeling protocol submitted to EPD on February 26, 2004. This protocol was approved in advance of the Application submission as documented in the protocol acceptance letter from Mr. James Stogner of the Georgia EPD on March 1, 2004.

In addition, for the primary modeling, the SIA was as follows: (1) 20.5 km for 24-hr SO_2; and (2) 12.3 km for 3-hr SO_2. These figures were presented in Table 6.2 on page 6-2 of the Application. The revised modeling report calculated the SIA for the 3-hr SO_2 as 31.6 km. Sony Magnetic Products-Dothan is 36 km from the Facility as shown in Appendix G; thus, it is outside of all of the SIA's and was properly excluded from the modeling per the 20D procedure.

- The Georgia Power Plant Mitchell source should be included in the modeling inventory because it is a very large emission source located just beyond the SIA plus 50 km distance.

Response: Georgia Power Plant Mitchell was included in the National Ambient Air Quality Standards (NAAQS) cumulative modeling. Plant Mitchell is not a PSD increment consuming source and thus is not required to be included in PSD increment modeling. Mitchell was identified as GA587 through GA589 and the parameters modeled for Mitchell were identified on page 8 of Appendix G of the Application.

- The inventory information for Great Southern Paper and Engelhard on pages 13-15 is not complete. Explanations concerning the missing information and status of this source in this modeling inventory should be provided.

Response: EPD believes that the inventory information is complete. The only information that may appear to be missing is the annual emission rates. However, this is immaterial since each of the modeled sources utilized the short term emission rate for both the short term and annual model runs. Each of the sources identified on pages 13-15 as being included in the model were modeled. Any source that was not modeled was determined to be duplicative of another source already in the model (and so noted in the inventory list).

- The PSD inventory of other sources appears to have used the minor source baseline date associated with the location of the sources to identify PSD increment consuming emissions units. The applicable minor source baseline dates of concern are those associated with the receptors. Confirmation is needed that the proper minor source baseline dates have been used to identify the modeled inventory of PSD increment consuming sources.

Response: The statewide minor source baseline dates in Alabama are:
SO_2 – November 27, 1977
PM – November 27, 1977
NO_2 – February 8, 1988

The statewide minor source baseline dates in Florida are:
SO_2 – December 27, 1977
PM – December 27, 1977
NO_2 – March 28, 1988

The minor source baseline dates for SO_2, PM, and NO_2 are different in Georgia for each county/air quality control region. However, the earliest minor source baseline dates in Georgia are:
SO_2 – August 30, 1977 (Macon Co.)
PM – August 30, 1977 (Macon Co.)
NO_2 – May 5, 1988 (Glynn Co.)

The earliest NO_2 minor source baseline date in Georgia was triggered after either the Florida or Alabama NO_2 baseline dates were established.

Macon County is sufficiently distant from either Alabama or Florida to preclude the possibility of a modeled receptor exceeding a significant concentration of SO_2 or Pm in those states.

Next are:
SO_2 – September 8, 1977 (Camden Co.)
PM – September 8, 1977 (Camden Co.)

Camden County is sufficiently distant from Early County such that the possibility of a Camden-County modeled receptor reflecting a significant concentration of SO_2 or PM within 100 km of Early County is zero.

Next are:
SO_2 – February 18, 1978 (Bibb Co.)
PM – February 18, 1978 (Bibb Co.)

The minor source baseline dates for Florida and Alabama were already set by this date. The applicant conservatively included all Georgia sources of SO_2 and PM Increment consumption which was screened for sources to include in the modeled PSD Increment assessments.

d. Preliminary Determination Summary of Impact on Class I Areas - The following comments concern PSD Class I area modeling:

- Although the 40 CFR part 52, appendix W, regulatory CALPUFF model (i.e., CALPUFF version 5.711a, CALMET version 5.53a, and CALPOST version 5.51) was not used in the Class I area impact assessments, this is acceptable because project modeling pre-dates the November 2005 promulgation of the CALPUFF model.

Response: EPA has answered its own question regarding the acceptability of the CALPUFF model used to assess long-range transport issues at the Class I areas. EPD concurs with EPA's response.

- The visibility assessment shows impacts above acceptable levels at the St. Marks PSD Class I area. Although it was noted that the federal land manager (FLM) has considerable discretion in requiring cumulative visibility impact assessments, the preliminary determination does not indicate the FLM's determination that the modeled impact level is acceptable.

Response: The FLM did not provide any comments on the St. Marks visibility modeling other than questions about modeling methodology and potential for additional analyses. The methodology utilized to evaluate the results of the modeling and the various "beyond FLAG" analyses performed were the same as those performed for the Savannah Electric Plant McIntosh combined cycle unit in 2003. As shown on page 5-8 through 5-10 of Appendix M of the Application, with the "beyond FLAG" analysis, the highest impact the Facility would have on visibility is one day over 5% at 6.3%. Impacts of this level have been found to be acceptable in other circumstances including the Roundup facility in Montana, Wygen II facility in Wyoming, and Prairie State facility in Illinois.

- Cumulative PSD increment compliance modeling was required for SO_2 short-term periods. The cumulative modeling showed short-term SO_2 increment consumption much less than the PSD Class I increments. Note that the increased 3-hour SO_2 emissions rate used in the August 12, 2005, Supplemental Modeling Report has not been used in any Class I analysis. The expected effect of increased emissions on Class I area concentrations should be addressed.

Response: Attachment F of the August 15, 2005, letter contained an evaluation of the impacts of the higher 3-hour SO_2 emission rate at the two Class I areas. The results of the modeling showed that cumulative SO_2 impacts would still be below the 3-hour SO_2 increments even with the higher emission rate.

- Nitrogen deposition rate assessments for two Class I areas show values below the FLM Deposition Analysis Threshold (DAT). Sulfur deposition rates for both St. Marks and Bradwell Bay Class I areas were above the DAT. Further analysis by the FLM for Bradwell Bay determined that the predicted level of deposition would not cause adverse impacts. The DAT sulfur deposition rate for St. Marks was not addressed.

Response: As stated in the FLM DAT guidance document, "[t]he DAT is a deposition threshold, not necessarily an adverse impact threshold…. Both the NPS and the FWS utilize a case-by-case approach to permit review. Adverse impact determinations will be considered on a case-by-case basis for modeled deposition values that are higher than the DAT." The information on the modeled sulfur deposition was provided to the FLM for St. Marks. No additional questions or concerns were raised by the FLM regarding this issue, therefore no adverse impacts are expected.

Additionally, the sulfur DAT was based on the higher emission rate of 0.12 lb/MMBtu. Sulfur deposition is modeled on an annual basis, thus with the more restrictive maximum 30-day SO_2 emission rate of 0.105 lb/MMBtu, the modeled results will be conservative.

Moreover, the Forest Service analysis of the information provided to both the FLMs resulted in a favorable Forest Service finding for the deposition inputs at Bradwell bay and Bradwell Bay is the closest Class I area to the LEA facility.

e. Class II Area Modeling Procedures - The cumulative PSD increment and NAAQS modeling evaluations were performed using two procedures: one with and one without Georgia-Pacific Cedar Springs emissions and plant area (fence line). No further explanation is provided. The reason for the two procedures should be provided. In addition, the exact meaning of with/without Georgia-Pacific Cedar Springs area (fence line) should be provided.

Response: The logic for using two methodologies was discussed on page 31 of Longleaf Energy's July 11, 2005 letter to Ms. Heather Abrams of EPD. The explanation is repeated below for EPA's benefit.

> Per GDNR EPD guidance from Mr. James Stogner, two NAAQS analysis scenarios were modeled: (1) Longleaf emission sources were modeled along with NAAQS inventory sources (including all G-P emission sources) but no receptors were included within the G-P property and (2) Longleaf emission sources were modeled along with NAAQS inventory sources (excluding all G-P emissions sources) and with receptors included within the G-P property. Scenario (2) was modeled to ensure that adverse impacts from Longleaf and other NAAQS emission sources would not occur within the G-P property line.

EPD concurs with this response and maintains that this methodology was in accordance with EPA's Modeling Clearinghouse guidance.

Comments from US Department of the Interior – Fish and Wildlife Service

We are concerned that the proposed plant has the potential to directly and indirectly impact fish and wildlife resources by the sheer size of its construction site (1985 acres); as well as, facets of its operation. We recognize that the permit under consideration addresses only one aspect of this project's environmental impacts, air quality. However, discussions as the project moves through the other State and Federal regulatory reviews that will be required, and within which EPD will be involved.

16 Longleaf Associates recognized that St. Mark's National Wildlife Refuge in Florida would be within the airshed of the generating plant. Permit documents include modeling information regarding potential impacts to the Wilderness Area of the Refuge. It is our understanding that EDP personnel are in ongoing discussions with the Service's Air Quality Branch.

Response: During its permit application and review process, LEA and EPD consulted with both the Service's Air Quality Branch as well as the relevant Federal Land Manager's (FLM) for Class I areas, including the FLM for St. Marks National Wildlife Refuge (St. Marks). LEA's modeling analysis concluded that the Facility would have no significant impact on St. Marks. The Service's Air Quality Branch did not dispute or otherwise comment on this conclusion.

17 The documents provided regarding the construction site do not describe the existing conditions. It is likely that wetlands, and the fish and wildlife that inhabit them, will be destroyed during plant construction. We will provide comments during the review process associated with the Corps of Engineers permit program under the Clean Water Act. We will be recommending that wetland and stream impacts be avoided, minimized and, where appropriate, mitigated.

Response: LEA has already applied for and received its permit (number 200600904) from the US Army Corps of Engineers for the wetland and stream impacts associated with the project. As the permit indicates, the impacts caused by the construction of the Facility will be limited to the water supply and discharge pipelines and the outfall in the river. Further, the already limited impacts that may occur will be minimized in several ways. First, LEA's Corps permit requires LEA to implement mitigation measures. Second, LEA's preliminary design was carefully planned so the Facility will comply with Georgia's Erosion and Sedimentation Act[1] which requires specific measures to minimize any impact to streams and rivers and their riparian habitat. In sum, LEA has taken several steps to ensure that any wetland and stream impacts at the Facility will be minimized and mitigated.

[1] O.C.G.A. § 12-7-1 *et seq.*

18 We are also concerned that habitat impacts may include impacts to listed species. At least three listed muscles (gulf moccasinshell, oval pigtoe, shinyrayed pocketbook) are known to occur in Early County. They are known from Sawhatchee Creek which is a few miles from the construction site. If the stream reaches within the construction site are habitat for listed mussels, Longleaf Associates should contact Service regarding responsibilities under the Endangered Species Act.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users.

19 The permit documents indicate that Longleaf will withdraw approximately 27 million gallons per day (MGD) and discharge about 5.54 MGD. It is not clear where the consumption of approximately 18 MGD will occur nor do the documents explain how the amount of consumption could be minimized. As you are well aware, water use in the Apalachicola-Chattahoochee-Flint River basin continues to be a critical natural resource issue, and a legally sensitive one. We have serious concerns about the long-term impacts of numerous projects that remove water from the ACF system. Downstream impacts of the proposed withdraw need to be considered in light of the needs of the entire ACF system, including listed species.

Response: LEA coordinated closely with the Georgia EPD Watershed Protection Branch in the permitting of the 27 MGD usage and 5.54 MGD withdrawal. As shown by the water balances included in the NPDES and water withdrawal permit applications, the majority of the consumptive water use will be for the cooling towers associated with the project, although additional consumptive use includes wetting of the fly ash, dust control, and for quench of the bottom ash.

First, LEA implemented an innovative water recycling program through its use of treated effluent from the Georgia Pacific paper mill located just south of the Project. Under expected normal operating scenarios, no water will be withdrawn from the Chattahoochee River for use at the Facility. Instead, the Facility will rely solely on Georgia Pacific's cooling water and treated process wastewater to meet its water needs. On those rare occasions when the Facility will not be able to meet its needs with Georgia Pacific's effluent, EPD has stated in LEA's draft that the combined withdrawal for the Facility and Georgia Pacific will not exceed the 144 MGD withdrawal that Georgia Pacific is allowed to use. Consequently, the Facility's water needs will not result in a net increase of water withdrawal from the Chattahoochee River.

20 Please include this office in future announcements regarding permit proposals associated with this project. Additionally, we would like to receive copies of (or an internet link to) the final decision documents associated with this air quality permit.

Response: EPD will notify the Department of Interior when the final permit issued.

Comments from Longleaf Energy Associates, LLC

21. Page 2 of 27
Source S02 – The ID Nos for the Air Pollution Control Devices should be LN2, CR2, DS2, and F02.

Response: EPD agrees and the above changes have been made.

22. Page 5 of 27
Condition 1.5 – LEA is requesting that the condition be clarified by adding in a phrase "for the main boilers, S01 and S02, when firing clarifier sludge." This clarification would serve to identify that the NESHAP provision will only apply in the event that LEA is burning clarifier sludge. This clarification is similar to the clarification in Condition 1.12 in which the NESHAP ZZZZ is identified to apply to the emergency diesel equipment.

Response: EPD agrees and the above changes have been made.

23. Page 6 of 27
Condition 1.9 – LEA is requesting that the condition be clarified by adding in a phrase "for the main boilers, S01 and S02" at the end of the condition. This clarification would serve to identify that the NSPS and its requirements are only applicable to the main boilers. This clarification is similar to the clarification in Condition 1.12 in which the NESHAP ZZZZ is identified to apply to the emergency diesel equipment.

Response: EPD agrees and the above changes have been made.

24. Page 6 of 27
Condition 1.10 – LEA is requesting that the condition be clarified by adding in a phrase "for the auxiliary boiler, S03" at the end of the condition. This clarification would serve to identify that the NSPS and its requirements are only applicable to the auxiliary boiler. This clarification is similar to the clarification in Condition 1.12 in which the NESHAP ZZZZ is identified to apply to the emergency diesel equipment.

Response: EPD agrees and the above changes have been made.

25. Page 6 of 27

Condition 1.11 – LEA is requesting that the condition be clarified by adding in a phrase "for coal conveying and processing equipment and the coal silos" at the end of the condition. This clarification would serve to identify that the NSPS and its requirements are only applicable to the those specific portions of the coal handling and storage equipment. This clarification is similar to the clarification in Condition 1.12 in which the NESHAP ZZZZ is identified to apply to the emergency diesel equipment.

Response: EPD agrees and the above changes have been made.

26. Page 8 of 27

Condition 2.9 – The condition currently identifies the control equipment for the lime and fly ash silos to be fabric filters. LEA is requesting that the condition be clarified to vent filters to more specifically identify the control as the passive form of fabric filtration.

Response: EPD agrees and the above changes have been made.

27. Page 8 of 27

Condition 2.14.c – LEA is requesting that the condition be clarified by adding in the 3-hour compliance averaging period for filterable PM. Total PM is only to be measure via stack testing but filterable PM will be continuously measured with a CEMS.

Response: EPD agrees and the above changes have been made.

28. Page 9 of 27

Condition 2.14.l – LEA would like to see the emission rates for mercury be specifically identified to be on a gross MW output basis.

Response: EPD agrees and the above changes have been made.

29. Page 10 of 27

Condition 2.16 – LEA is requesting that the condition be amended by adding the phrase "unless such use is required for emergency purposes." In the event of an emergency that would cause either of the emergency engines to exceed the permitted hours, LEA prefers to have that authorization in the permit rather than being required to notify the state of an impending exceedance while at the same time dealing with an emergency.

Response: EPD does not include such statements into the permit conditions. This is to require the facility to notify EPD and it is up the Stationary Source Compliance Program's discretion if the situation is deemed an emergency and what action would be taken if any. No changes are made to the permit based on this comment.

30. Page 12 of 27

Condition 4.1 – LEA believes there are some inconsistencies in the various components of this section and LEA is requesting that the inconsistencies be resolved in order to prevent later confusion. Item h specifically identifies this for the auxiliary boiler. However, items n, o, and p will only be used for the main boilers but are not similarly referenced.

Response: EPD agrees and the above changes have been made.

31. Page 12 of 27

Condition 4.1.g – Because item g is not referenced for use by either the main boilers or the auxiliary boiler, LEA is requesting that it be deleted from the Condition.

Response: EPD agrees and the above changes have been made.

32. Page 13 of 27

Condition 4.1.r – LEA is requesting that the condition be clarified by adding in the phrase "using the CEMS required by Condition 5.2" at the end of the Condition. This clarification is similar to the clarifications in Condition 4.1.s and 4.1.t in which the permit condition requiring the CEMS for NO_x and SO_2 and the COMS for opacity are referenced.

Response: EPD agrees and the above changes have been made.

33. Page 13 of 27

Condition 4.1 – LEA is requesting that an additional item be added to this condition for CO similar to Conditions 4.1.s and 4.1.t. Condition 8.10 for recordkeeping already identifies the CEMS for CO to be intended for compliance. In order to prevent any confusion as to why CO is not addressed in the Performance Testing section, an additional item similar to item s or t should be added for CO.

Response: EPD agrees and the above changes have been made.

34. Page 13 of 27

Condition 4.1 – LEA is requesting that an additional item be added to this condition for filterable PM similar to Conditions 4.1.s and 4.1.t. Condition 5.2.f requires that LEA install a CEMS for filterable PM but the permit does not currently identify what will be done with the information generated by that output.

Response: EPD agrees and the above changes have been made.

35. Page 14 of 27

Condition 4.2 – LEA does not understand the inclusion of items i and j. Condition No. 2.14.l is the annual emission limitation for mercury and a performance test will not be able to show demonstration on an annual limit without significant extrapolation. In addition, there is not a performance test specified for mercury other than during firing of clarifier sludge which is addressed in Condition 4.1.k. Condition 4.1.r already identifies that compliance with Condition 2.14.l is to be done according to the CFR methodology (which requires a CEMS or sorbent trap, not a performance test), therefore these requirements do not seem to apply. For this reason, LEA is requesting that these two items be removed.

Response: 40 CFR 60, Subpart Da specifies in sections 60.48Da(l) (Compliance Provisions), 60.49Da(p) (Emission Monitoring), and 60.50Da(h) Compliance Determination) all specify the method of compliance with the applicable limits as the CEMs. Therefore the specific testing requirement in Condition 4.1k is not needed. Longleaf can comply with the applicable requirements in Subpart Da without needing a one-time test for mercury. EPD agrees and the above changes have been made.

36. Page 17 of 27

Condition 5.2.g – LEA is uncertain if this provision should be interpreted to mean that an oxygen or carbon dioxide monitor is also required at the scrubber inlet where LEA will be monitoring uncontrolled SO_2 emissions. If an oxygen or carbon dioxide monitor is not required at the scrubber inlet to determine inlet lb/MMBtu, then the condition could be modified to say "**outlet** SO_2 or NO_x emissions are monitored."

Response: 40 CFR 60.45(e) requires an accurate measurement of oxygen or carbon dioxide at each CEMS location due to the BACT limits are in units of lb/MMBtu. EPD has clarified the permit condition to state that measuring oxygen or carbon dioxide is required at each location where SO_2, NOx, PM, and CO monitors are required as stated in Condition 5.2 of the permit.

37. Page 18 of 27

Condition 8.6 – LEA is requesting that the acronym ULSD used in Condition 8.25.f be defined either in this condition or in Condition 2.13. Additionally in order to avoid potentially conflicting definitions of ULSD, LEA believes Conditions 2.13 and 8.6 should be linked.

Response: EPD agrees and the above changes have been made.

38. Page 19 of 27

LEA is requesting that an additional condition be added to Section 8 similar to Conditions 8.8 to 8.10 addressing the PM filterable CEMS. Condition 5.2.f requires that LEA install a CEMS for filterable PM but the permit does not currently specify the methodology for demonstration of compliance.

Response: EPD agrees and the above changes have been made.

39. Page 19 of 27

Condition 8.10 – LEA is requesting that the word "assure" be changed to "determine". The word determine is used in Conditions 8.8 and 8.9 and LEA would prefer to have consistency in the permit conditions.

Response: EPD agrees and the above changes have been made.

40. Page 20 of 27

Condition 8.11 – LEA is requesting that this condition be revised to be similar in structure to Conditions 8.8 through 8.10 so there is not confusion as to the intent of the conditions. If 8.11 is revised to match the structure of Conditions 8.8 through 8.10, then LEA believes Condition 8.14 would no longer be needed.

Response: EPD agrees and the above changes have been made.

41. Page 20 of 27

Condition 8.15 – LEA is requesting that this Condition be clarified to identify that the 24-hour total mercury emissions being calculated should only be mercury emissions generated from combustion of clarifier sludge.

Response: EPD agrees and the above changes have been made.

42. Page 26 of 27

Condition 8.25 – LEA understands this condition to means that the quarterly written reports should not include the daily calculated mercury emission rates from the combustion of clarifier sludge. If the quarterly written reports are intended to include the daily mercury emission rates, LEA is requesting that an additional item added specifying the need for reporting of the 24-hour emission information.

Response: EPD agrees and the above changes have been made.

Comments from Georgia Center for Law in the Public Interest

43. EPD HAS FAILED TO CONSIDER THE DISPROPORTIONATE IMPACT OF THE PLANT ON MINORITY AND LOW-INCOME COMMUNITIES.

EPD has failed to consider the disproportionate impact of its decision to grant preliminary approval for the Longleaf Energy Station on low income and minority communities. The importance of considering these factors cannot be underestimated as pollution from coal-fired power plants impacts certain communities at a higher rate than the general population. It is well established that fine particle pollution from power plants have been linked to asthma attacks, respiratory disease, heart attacks, and premature deaths.[2] Among the pollutants emitted from power plants are nitrogen oxides and sulfur dioxide, which form particle pollution. These fine particles are inhaled deeply into the lungs, affecting both the respiratory and cardiovascular systems.[3] *While pollution from power plants affects all people 68 percent of African Americans live within 30 miles of a coal-fired power plant.*[4] *Moreover, asthma occurs disproportionately among African Americans in Georgia, who are two to three times more likely than whites to suffer asthma-related deaths.*[5] Nationally, although African Americans represent 12.7% of the U.S. population, they account for 26% of asthma deaths.[6] Even more alarming is the fact that African American children are five times more likely to die from asthma than white children.[7]

LS Power, by locating the Longleaf Energy Station in Early County, is perpetuating the trend whereby African Americans suffer a disparate burden of air pollution. According to U.S. Census data, 50.2% of Early County residents are African American, while African Americans make up only 29.6% of Georgia's general population. Moreover, 23.3% of Early County residents are below the poverty line, according to Census data; this compares with 13.3%, statewide.

Despite the fact that vulnerable communities would suffer a disparate burden from the proposed plant, EPD publicly announced that it has not considered these factors in its decision-making process.[8] EPD should consider these factors before issuing this permit as it is well established that consideration of these factors is essential to

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[2] Clear The Air, "Dirty Air, Dirty Power, Mortality and Health Damage Due to Air Pollution from Power Plants," June 2004.
[3] Black Leadership Forum, et al. "Air of Injustice, African Americans and Power Plant Pollution," October 2002, available at http:/www.cleartheair.org/fact/injustice.pdf.
4 American Lung Association, Lung Disease Data in Culturally Diverse Communities: 2005. Lung Disease Data at a Glance: Asthma, available at http://www.lungusa.org.
5 The Georgia Conservancy, citing Dr. Richard Bright of the Morehouse School of Medicine, available at www.gaconservancy.org.
6 American Lung Association, Lung Disease Data in Culturally Diverse Communities: 2005. Lung Disease Data at a Glance: Asthma, available at http://www.lungusa.org.
7 "Clean Air for Life: Dirty Air & Your Health. Asthma and Air Pollution," available at http://www.environmentaldefense.org.
[8] EPD Question and Answer Session on the Longleaf Energy Station in Early County; October 17, 2006.

eliminating inequitable exposure to disproportionate environmental and human health risks. In Executive Order 12898, the President acknowledged the importance of considering factors of environmental justice in administering federal programs and called upon agencies to take measures to address the disproportionate, adverse human health or environmental effects of its programs, policies, and activities on minority and low-income populations.

> To the greatest extent practicable and permitted by law, ... each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States.... [9]

Congress, through the federal Clean Air Act delegates authority to state permitting agencies to promulgate and enforce air quality standards.[10] As an agency responsible for the administration and enforcement of federal laws and programs, EPD is responsible for integrating the consideration of disparate impacts to sensitive communities into its decision-making and permitting processes. The state permitting authority, in administering federal law, should not be able to circumvent federal directives in carrying out their delegated authority. Accordingly, prior to any final decision, a thorough analysis of the disproportionate environmental and public health impacts on the surrounding communities should be completed. Absent such an analysis, the permit should not be issued.

Response: EPD has complied with all requirements associated with this permitting action. In addition to meeting all of its regulatory obligations, the EPD has taken extra efforts to ensure that the community around the proposed facility has had easy access to information about the proposal as well as the opportunity to voice concerns about the project. The EPD held two question-and-answer sessions to provide information and answer questions from the public, on January 23, 2006 and October 17, 2006 in the Early County High School's Mangham Auditorium. At these meetings, the EPD provided staff contact information so that the public could have additional questions answered, if needed. In fact, the EPD has responded to many public inquiries throughout this process. The EPD also set up a special section on our web page just for this proposal that contains an extensive amount of information on this proposal. The web site is located at: **http://www.georgiaair.org/airpermit/psd/dockets/longleaf/**.

The final permit for Longleaf Energy imposes very stringent emissions limits making this facility one of the least emitting coal-fired power plants ever permitted in the United States. In addition, the EPD recently adopted rules requiring significant reductions in sulfur dioxide, nitrogen oxides, particulate matter, and mercury emissions from all

9 Exec. Order No. 12,898, 59 Fed. Reg. 7629 (1994).
10 42 U.S.C. § 7409(a).

existing coal-fired power plants in the entire state. Overall, state-wide, emissions of these pollutants will be decreasing significantly.

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

44. THE PROPOSED PERMIT FAILS TO COMPLY WITH FEDERAL AND GEORGIA LAW BECAUSE THE BACT DETERMINATION IS DEFECTIVE.

In general, the Best Available Control Technology ("BACT") determination is flawed in part because EPD failed to follow their own procedures in establishing BACT. EPD asserts in the Preliminary Determination ("PD") that the United States Environmental Protection Agency's ("EPA") 1990 Draft New Source Review Workshop Manual (NSR Manual) are "EPD's procedures for performing top down BACT". Failure to correctly follow these procedures leads to an errant proposed determination of BACT. Errors include failure to include technologies for evaluation, failure to investigate performance of technologies in combination, failure to investigate technologies at their highest level of performance and failure to document control efficiencies (percent pollutant removed), expected emissions rates (tons per year, pounds per hour), and expected emissions reduction (tons per year) as well as energy, environmental and economic impacts of different technologies and combinations of technologies.

Response: This comment is not correct. PSD regulations require the use of Best Available Control Technology (BACT) and the emission limits and operational requirements in this permit satisfy that requirement.

EPD failed to compare and consider several technically feasible options including Integrated Gasification Combined Cycle ("IGCC") and comparison of subcritical, supercritical and ultra-supercritical pulverized coal technologies. A supercritical boiler is clearly an inherently less polluting technology in comparison to a subcritical boiler in that, due to the higher thermal efficiency of a supercritical boiler, it produces more electrical power for the amount of coal burned. This means that on an hourly basis and annual basis, the supercritical boiler is expected to produce less pollution than a sub-critical boiler generating the same amount of electricity. In order to accurately compare the emissions from IGCC, subcritical, supercritical and ultra-supercritical technologies for generating electricity from the combustion of coal, BACT should also be listed in terms of pounds per gross megawatt hour (lbs/MW-hr) as well as lbs/MMBtu. The importance of considering thermal efficiency in assessing overall emissions is documented in EPA's "Environmental Footprints and Costs of Coal-Based Integrated

Gasification Combined Cycle and Pulverized Coal Technologies, July 2006." The information for bituminous coal from Exhibit ES-2 of this report is included below to show the importance of considering overall efficiency in establishing a BACT limitation.

Response: Please refer to Comments 12 and 45 of this Final Determination for more information on this topic.

Exhibit ES-2 (EPA July 2006)

	Bituminous Coal			
Environmental Impact lb/MWh	IGCC Slurry Feed Gasifier	Sub-Critical PC	Super-Critical PC	Ultra Super-Critical PC
No_x (NO_2)	0.355	0.528	0.494	0.442
SO_2	0.311	0.757	0.709	0.634
CO	0.217	0.880	0.824	0.737
Particulate Matter[1]	0.051	0.106	0.099	0.088
Volatile Organic Compounds (VOC)	0.012	0.021	0.020	0.018
Solid Waste[3]	65	176	165	155
Raw Water Use	4960	9,260	8,640	7,730
SO_2 Removal Basis, %	99	98	98	98
No_x Removal Basis[2]	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu

45. Federal and Georgia Law Require Evaluation of IGCC in the BACT Analysis.

Georgia incorporates by reference the federal definition of BACT, found at 40 C.F.R. § 52.21 (b)(12).[11] Pursuant to Section 52.21(b)(12), BACT is defined, in pertinent part, as follows:

> Best available control technology means an emissions limitation (including a visible emission standard) based on *the maximum degree of reduction* for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is *achievable for such source or modification through application of production processes or available*

[11] See also Georgia Rules for Air Quality Control 391-3-1-.02(7)(a)(2)

> *methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.*[12]

BACT requires a comprehensive analysis of all potentially available emission control measures, expressly including "production processes," "fuel cleaning," or "innovative fuel combustion techniques." The emissions limitation springs from an analysis of what will produce the "maximum degree of reduction" that is "achievable." EPA has repeatedly acknowledged that Prevention of Significant Deterioration ("PSD") emissions limitations will become more stringent over time as control technologies improve and new, cleaner processes are introduced. Moreover, as is clearly stated in the definition of BACT, emission limits identified as BACT must incorporate consideration of more than just add-on emission control technology - they must also reflect appropriate considerations of fuel quality (such as low sulfur coal) and process changes (including, specifically, innovative combustion techniques such as coal gasification). Despite federal requirements, EPD has adopted the following flawed reasoning: as a matter of law, neither it or LS Power was required to consider IGCC as an available option in the BACT process for any pollutant because IGCC represents a different process and would be "redefining the source." This conclusion is erroneous.

EPD acknowledges that the definition of BACT includes "innovative fuel combustion techniques."[13] However, EPD goes on to interpret Congress' inclusion of such techniques in the definition of BACT as somehow excluding consideration of such techniques: "we do not believe Congress intended for an `innovative fuel combustion technique' to be considered in the BACT review when application of such a technique would redesign the proposed source...."[14] Such misinterpretation of the plain meaning of the terms rests on two faulty assumptions: 1) that Congress did not intend for innovative fuel combustion techniques to be considered, despite such plainly being called for; and 2) that consideration of IGCC would somehow be redefining the source.

The specific inclusion of "innovative combustion techniques" in the definition of BACT seems enough to refute EPD's assertion that Congress did not intend for such techniques to be considered in the BACT analysis. If the plain meaning of the terms of the statute are not enough, one can look to the legislative history of the amendment which added the term "innovative fuel combustion techniques" to confirm that coal gasification is exactly the type of technique Congress had in mind when it added the term to the BACT definition.

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major

[12] 40 C.F.R. § 52.21 (b)(12).

[13] PD, at 198.
[14] *Id.*

> emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls.
>
> The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment." *And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion.* But, this intention is not explicitly spelled out, and *I am concerned that without clarification, the possibility of misinterpretation would remain.*
>
> *It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account*—be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, *gasification,* or liquefaction; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers.
>
> The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation.[15]

In sum, Congress recognized the existing "production processes" language should cover coal gasification, but added "innovative fuel combustion techniques" so as "to leave no doubt."[16]

Moreover, requiring that IGCC be considered in the BACT analysis is not redefining the source as this technology has previously been used at other facilities within the same source category, namely, other coal burning power plants.

EPD attempts to distinguish IGCC from control technologies applicable to the Longleaf facility as an "alternative ... that would wholly replace the proposed

15 123 Cong. Rec. S9421, S9434-35 (June 10, 1977) (emphasis added).

16 This legislative history is further bolstered by the extensive discussion of the rigor and purposes of the BACT requirement that informed its adoption. Congress explained that the Clean Air Act "requires" BACT in order "to minimize emissions." S. Rep. No. 95-127 at 29 (1977). One of the core aims was to compel the "rapid adoption of improvements in technology as new sources are built." Id. at 18. Indeed, Congress intended BACT as "[p]ossibly [the] most important" of the 1977 Act's many technology-fostering measures. Id. This technology-forcing philosophy was "fundamental" to Congress's adoption of the BACT requirement and congressional efforts throughout the 1977 amendments "to accentuate technological innovation in the control of air pollutants." Id. at 10.

facility with a different type of facility." Such a distinction is patently false. IGCC is a proven technology utilized at power generation facilities. EPD rationalizes this distinction by claiming that IGCC technology "would necessitate different types of expertise on the part of the company and its employees." If that argument were legitimate, then the entire new source review permitting process would fall apart because any change from an application required by EPD would necessitate different expertise on the part of the company. For example, if the company proposed a cyclone as BACT, and EPD based BACT on a baghouse, the company would have to respond with a different design, different vendors, and different employees.

Fundamentally, EPD was incorrect as a matter of law by not requiring IGCC to be considered as part of each BACT analysis in this permit. Accordingly, EPD should withdraw the PD and the draft permit and conform them to the law.

Response: IGCC is a physically and chemically distinct method of producing electricity that cannot be compared to the PC fired boiler proposed at the Facility without redefining the source. Neither federal law nor Georgia law require the consideration of technologies that would redefine the proposed source.

46. Proper BACT Analysis for IGCC

A proper BACT analysis for the Longleaf Energy Station would include IGCC technology as part of the analysis. EPA generally requires a "top-down" BACT analysis, as does Georgia.[17] The NSR Manual identifies five steps in a top-down BACT analysis:

1) Identify all control technologies;

2) Eliminate technically infeasible options;

3) Rank remaining control technologies by control effectiveness;

4) Evaluate most effective controls and document results; and then

5) Select BACT.[18]

1. Step One: Identify All Control Technologies—IGCC Is Available.

In the first step of the top-down BACT analysis, the applicant must consider all "available" control options. In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available is used in its

[17] NSR Manual, B.2; Capp, *supra* n, at 2.

[18] NSR Manual, B.6.

broadest sense under the first step and refers to control options with a `practical potential for application to the emissions unit' under evaluation. ... The goal of this step is to develop a comprehensive list of control options."[19] Thus, a control technology is "available" when "there are sufficient data indicating (but not necessarily proving)" the technology "will lead to a demonstrable reduction in emissions of regulated pollutants or will otherwise represent BACT."[20]

Under these standards, IGCC is unquestionably available. The U.S. Department of Energy ("DOE") declared in 2002 that "[c]oal gasification is a well-proven technology that has had many applications, ... most recently, ... large-scale [IGCC] power generation.[21] Similarly, ChevronTexaco, in an October 2002 presentation, stated that "IGCC is a current viable choice for clean coal capacity."[22] On-the-ground experience bears out these statements.

Two commercial IGCC electric generating units are currently in operation in the United States: Tampa Electric Company's 262 MW unit at the Polk plant in Florida and Global Energy's 192 MW unit at the Wabash River plant in Indiana,[23] which both rely on coal as a fuel source.[24] Two other coal-based IGCC plants operate in Europe: NUON/Demkolec is a 253 MW plant in the Netherlands, and ELCOGAS/Puertollano in Spain is 298 MW.[25]

Two other IGCC facilities in the United States have received permits but are not yet operating. On March 26, 2002, the Ohio Environmental Protection Agency issued an air permit to the Lima Energy Company to construct two 290 MW IGCC units in Lima, Ohio;[26] in January 2004, the Wisconsin Department of Natural Resources approved a permit for an IGCC plant in Milwaukee County, Wisconsin.[27]

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[19] In re: Knauf, 1999 EPA App. LEXIS 2 at *21 (quoting NSR Manual at B.5) (emphasis added by EAB); see also In re: Steel Dynamics, Inc., 9 E.A.D, 165, 2000 EPA App. LEXIS 18, *50 n.24 (EAB, June 22, 2000) (citing Knauf with approval); In re. Ogden Martin Systems of Onondaga, Inc, et al, 4 E.A.D. 405, 1992 EPA App. LEXIS 45, *15 n.12 (EAB, Dec. 1, 1992) ("`Available' control options are those which are known to have realistic potential for application to the regulated pollutant").

[20] In re: Spokane Regional Waste-to-Energy Applicant, 2 E.A.D. 809, 1989 EPA App. LEXIS 23, *24-*25 (EAB, June 9, 1989).

[21] Major Environmental Aspects, 1-1.

[22] Luke O'Keefe & Karl Sturm, ChevronTexaco, "Clean Coal Technology Options - A Comparison of IGCC vs. Pulverized Coal Boilers," Presentation to the 2002 Gasification Technologies Conference, 8 (Oct. 28, 2002).

[23] The Wabash unit was previously owned by Cinergy. Global Energy purchased it in 1999. See http://www.globalenergyinc.com/920206.html.

[24] Major Environmental Aspects, 1-20, Table 1-4.

[25] Id.

[26] Final Permit to Install 03-13445 (Ohio EPA, March 26, 2002).

[27] Wisconsin Dep't of Natural Resources Air Pollution Control Construction Permit No. 03-RV-166 (Jan. 14, 2004).

IGCC power plants continue to be proposed for commercial development in the United States. At least two IGCC plants have pending applications for air permits: the 677 MW Cash Creek Generating Station in Henderson County, Kentucky;[28] and the 770 MW Taylorville Energy Center IGCC facility in Christian County, Indiana.[29]

At least three other facilities have begun seeking regulatory approval but have not applied for environmental permits. Two subsidiaries of American Electric Power ("AEP") have announced plans to build a 629 MW IGCC unit in Meigs County, Ohio; the Ohio Public Utilities Commission has granted AEP's application for a mechanism to recover preconstruction costs for the facility.[30] Excelsior Energy Inc. plans to build one or more 600 MW IGCC units in Itasca and/or St. Louis County, Minnesota, to be known as the Mesaba Energy Project, and has filed a petition with the Minnesota Public Utilities Commission for approval of a 603 MW Power Purchase Agreement with Northern States Power.[31] Finally, Appalachian Power, another affiliate of AEP, has filed an application with the West Virginia Public Utilities Commission to build a 600 MW IGCC facility in Mason County, West Virginia.[32]

Numerous other facilities have been proposed but have not begun the approval process: PSI Energy, the Indiana operating company of Cinergy Corp., has announced that it is beginning preliminary engineering and design work for a proposed 600 MW IGCC plant to be located somewhere in Indiana.[33]

- Southern Company has announced plans to build a 285 MW IGCC unit at the Orlando Utilities Commission's Stanton Energy Center, near Orlando, Florida.[34]

- Citgo Petroleum Corporation has announced plans to develop a 670 MW IGCC plant in Lake Charles, Louisiana.[35]

- Energy Northwest has proposed a 600 MW IGCC plant (2300 MW units) to be located in the Port of Kalama, near Longview, Washington.[36]

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[28] Kentuckiana Engineering Co,, Prevention of Significant Deterioration, Title V Operating Permit & Phase II Acid Rain Joint Application for Cash Creek Generating Station, Henderson County, KY (July 2005).
[29] Taylorville Application.
[30] In re: Application of Columbus Southern Power Co. & Ohio Power Co. for Authority to Recover Costs Associated with the Ultimate Construction & Operation of an Integrated Gasification Combined Cycle Electric Generating Facility, 2006 Ohio PUC LEXIS 249 (Ohio P.U.C., April 10, 2006).
[31] http://www.excelsiorenergy.com/News/Mesaba%20Site%20Announcement%20050829.pdf; http://www.excelsiorenergy.com/News/PPA%20Press%20Release%20122705C.pdf.
[32] http://www.appalachianpower.com/news/releases/viewrelease.asp?releaseID=221.
[33] http://www.gepower.com/about/press/en/2006_press/032206.htm.
[34] http://www.energy.gov/print/3241.htm.
[35] *See* http://goliath.ecnext.com/comsite5/bin/pdinventory.pl?pdlanding=l&referid=2750&item_id=0199-3458822#abstract.

- SouthWestern Power Group announced that the Bowie Power Station planned for southeastern Arizona, which was originally proposed as a natural gas-fueled 1000 MW plant, would be built as a 600 MW IGCC plant.[37]

Moreover, IGCC units are available from major well-known vendors. Coal gasification equipment is available from GE, Shell, and ConocoPhillips. The National Coal Council, in a May 2001 report, confirms that IGCC is "viable, commercially available technology."[38] The Center for Energy and Economic Development (CEED) states that, "IGCC technology is available for deployment today."[39]

In light of all the existing and proposed plants, and commercial availability, there can be no doubt that IGCC is "available."

2. Step Two: Eliminate Technically Infeasible Options—IGCC Is Feasible.

The second step of the BACT analysis eliminates options based upon physical, chemical, and engineering principles that would preclude the successful use of an option.[40] IGCC presents no technical feasibility issues for the Longleaf Energy Station. The NSR Manual states "a permit requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit,"[41] so feasibility of IGCC can be assumed. More specifically for the Longleaf Energy Station:

- Design Fuel: The Longleaf Energy Station proposes to use "Powder River Basin (PRB) coal and/or Central Appalachian coal."[42] Many coal types have been used in coal gasification plants, including numerous eastern bituminous coals as well, as sub bituminous coal.[43] Therefore, the design fuel poses no technical barriers for an IGCC plant.

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[36] Energy Northwest, Keeping Current (Nov. 2005), available at http://www.energy-northwest.com/news/keeping_current/KeepingCurrent.pdf.
[37] Ainslie S. Wittig, "Environmentally Friendly Power Plant," San Pedro Valley News-Sun (June 3, 2006), available at http://www.bensonnews-sun.com/articles/2006/06/03/news/news4.txt.
[38] National Coal Council, Increasing Electricity Availability from Coal-Fired Power Plants in the Near Term, at 20, Attachment 12 (May 2001).
[39] *See* www.ceednet.org/fueling/investing.asp.
[40] NSR Manual, B.7.
[41] *Id.*
[42] Longleaf Application, 1-3.
[43] Major Environmental Aspects, 1-20, Table 1-4.

- Availability: IGCC plants have demonstrated availabilities of 85% for single train gasifiers and greater than 90% for facilities with spare gasifiers.[44] Therefore, plant availability poses no technical barriers for an IGCC plant.

- Plant Size: Several plants in the 600 MW range have been proposed. Using multiple units would easily allow LS Power to meet its plans for a 1200 MW plant, as well as improve availability and create economies of scale improving the economics of the project.

- Water Use: IGCC plants use approximately one-half to two-thirds of the water a PC plant uses.[45] Water use is not a barrier to IGCC.

- Solid Waste: The wastes produced by IGCC plants are of a similar nature to those at PC plants, but the amount is approximately 30-50 percent less.[46] Therefore, waste disposal, if it is technically feasible for a PC plant, must also be feasible for an IGCC plant.

All of these factors show conclusively that IGCC is technically feasible.

3. Step Three: Rank Remaining Control Technologies by Control Effectiveness—IGCC Is Most Effective at Controlling All Criteria Pollutants.

"In step 3, all remaining control alternatives not eliminated in. step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review, with the most effective control alternative at the top."[47] This step clearly shows that IGCC power plants have lower emissions compared to the technology currently proposed for the Longleaf Energy Station.

The relevant comparison in the BACT determination is between recent IGCC emissions levels and the levels proposed by LS Power for the Longleaf Energy Station. The NSR Manual notes that existing permits are "sufficient justification to assume the technical feasibility of [a] technology or emission limit."[48] Similarly, levels proposed by applicants should be presumed to be achievable.

[44] See Section.c.4, infra.
[45] Major Environmental Aspects, 2-61.
[46] Id., 1-28, 2-63 to 2-64.
[47] NSR Manual, B.7.
[48] Id.

Table 1: Comparison of Emission Rates for Taylorville and Longleaf Energy Station

	Taylorville Energy Center (lb/MMBtu)	**Longleaf Energy Station (lb/MMBtu)**
SO_2	0.0117 (3-hr avg)	0.12 (30-day avg)
NO_X	0.0246 (24-hr avg)	0.07 (30-day avg)[49]
PM	0.0063 (3-hr avg)	0.015 (filterable, 3-hr-avg); 0.033 (total, 3-hr avg)
VOC	0.0017 (24-hr avg)	0.0036 (3-hr avg)
CO	0.036 (24-hr avg)	0.15 (30-day avg)
Lead	1.03 x 10-6 (no time period stated)	1.2 x 10-5 (annual avg)

As Table 1 shows, IGCC emissions levels are significantly lower than the levels LS Power proposes for each of the pollutants in the BACT analysis. In each case, the IGCC levels range from 9 percent to 47 percent of the levels proposed by LS Power (except for VOCs) using an averaging period at least as strict as the one proposed by LS. Because of IGCC's better heat rate, the advantage would be even greater if calculated on an output (lb/kWh) basis.

Table 2 translates these emission rates into annual tons of pollutants released per year assuming a capacity factor of 85% and 1200 MW of generating capacity, using the lowest emissions rates proposed by LS Power and the rates proposed for the Taylorville Energy Center.

[49] Although this is LS Power's proposed level, we believe BACT for a PC plant (assuming IGCC is not considered) would be 0.03 lb/MMBtu with a 24-hour averaging period. Thus, available PC technology would, if used, negate some but not all of IGCC's advantage in NOx.

Table 2: Annual' Tons of Emissions Released Under Typical Baseload Conditions

	LONGLEAF PC		IGCC		
Size (MW)	1200		1200		
Heat rate (Btu/KWh)	9760[50]		8540[51]		
Capacity Factor	85%		85%		
Electricity Generated (KWh)	8,935,200,000		8,935,200,000		
Required MMBtu/yr	87,207,552		76,306,608		
	Emissions rate (lb/MMBtu)	Annual Emissions (Tons/yr)	Emissions rate (lb/MMBtu)	Annual Emissions (Tons/yr)	Benefit of IGCC over PC
SO_2	0.12	5,232	0.0117	446	4786
NO_x	0.07	3,052	0.0246	939	2114
PM	0.015	654	0.0063	240	414
VOC	0.0036	157	0.0017	65	92
CO	0.15	6,541	0.036	1374	5167
Lead	0.000012	0.52	0.0000010	0.039	0.48
Total		15,960		3,164	12,573

Thus, at 85% capacity, an IGCC plant emits over 12,500 tons (about 80%) less criteria pollutants in a typical year. Simply put, IGCC is the superior technology for all criteria pollutants.

4. The Collateral Impacts Analysis Applied to IGCC.

The NSR Manual describes the analysis to be undertaken in Step Four of the top-down BACT analysis as follows:

> After the identification of available and technically feasible control technology options, *the energy, environmental, and economic impacts* are considered to arrive at the final level of control. At this point the analysis presents the associated impacts of the control option in the listing. For each option the applicant is responsible for presenting an objective evaluation of each impact. Both beneficial and adverse impacts should be discussed and, where possible,quantified. In general, the BACT analysis should focus on the direct impact of the control alternative.

[50] The heat rate for Longleaf is derived from MMBtu/hr figures at Longleaf Application, Appendix C, at 3.
[51] The heat rate for IGCC is based on the average of 4 existing IGCC plants, as set out in *Major Environmental Aspects,* 1-26, Table 1-7.

> If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.[52]

Applying this analysis confirms that IGCC is a superior alternative to conventional PC plants.

a. Energy Impacts

Existing IGCC plants have roughly a 10 to 20 percent more efficient heat rate than PC plants.[53] Thus, for energy considerations, IGCC is superior to conventional technology.

b. Environmental Impacts

Aside from the lower emissions of pollutants subject to the BACT analysis, other environmental advantages of IGCC have been widely recognized by parties ranging from agencies to large and small power producers.

EPA has noted in presentations that IGCC units use less water, and have global warming advantages, compared to conventional PC units.[54] Similarly, a report prepared for the DOE's National Energy Technology Laboratory noted that "gasification-based energy conversion systems are capable of providing stable, high-efficiency energy supply with reduced environmental impact compared with competitive technologies."[55]

On the industry side, James E. Rogers, formerly Chairman, CEO and President of Cinergy and now President and CEO of Duke Energy following its merger with Cinergy, has testified before Congress:

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[52] NSR Manual, B.8-B.9 (emphasis added).
[53] Major Environmental Aspects, 1-27, Table 1-8.
[54] E.g., Robert J. Wayland, U.S. EPA Office of Air and Radiation, OAQPS, "U.S. EPA's Clean Air Gasification Activities," Presentation to the Gasification Technologies Council Winter Meeting, 4 (Jan. 26, 2006).
[55] Major Environmental Aspects, ES-1.

> Cinergy is completing a feasibility study on the construction of an Integrated Gasification Combined Cycle power plant (IGCC)—the state of the art coal plant technology available to us today. It is relatively easier and less energy intensive to capture CO2 from an IRC's [*sic*] high pressure synthesis gas than from conventional pulverized coal flue gas, In addition, sulfur dioxide, nitrogen oxide and mercury emissions are substantially reduced with IGCC technology and because it is more efficient even without carbon capture components, it does reduce carbon emissions.[56]

Similarly, Global Energy, Inc., owner of the Wabash plant, says: "Gasification has been shown to be economically and environmentally superior to any other technology for beneficial recycling and elimination of multiple waste streams. The emissions from a gasification facility are dramatically lower in all categories when compared to a conventional coal-fired facility."[57]

IGCC's environmental advantages arise in several major areas.

i. Carbon Dioxide

First, and most importantly, IGCC presents substantial advantages over PC technology with respect to carbon dioxide (CO_2), the primary greenhouse gas responsible for anthropogenic contributions to global warming. There can be no serious debate that global warming is real and is here today.[58] Coal is one of the most significant sources of CO_2 emissions. Going forward, planning for power needs *must* include consideration of the carbon impacts of using coal.

As noted above, an IGCC plant is typically 10 to 20 percent more efficient in terms of heat rate than a PC unit;[59] thus, CO_2 emissions are reduced by that same amount. Furthermore, IGCC may be able to make even deeper cuts in CO_2 compared to conventional coal plants. Carbon capture and sequestration ("CCS") is an untested but potentially promising approach to addressing global warming. Because CO_2 can be isolated and captured before combustion when the volume is relatively small, IGCC facilities can capture the CO_2 in the syngas at a fraction of the cost of post-combustion CCS at other coal plants. EPRI estimates the cost to produce energy with CCS for a PC plant using bituminous coal at $75.4/MWh while the cost from an IGCC plant is only $61/MWh -$67/MWh.[60]

With this in mind, it becomes irresponsible to build conventional PC-fired plants. Every such plant locks in high carbon emissions and/or high removal costs for the

[56] Testimony of James E. Rogers, Chairman, CEO and President, Cinergy Corp., House Science Committee, Business Actions Reducing Greenhouse Gas Emissions (June 8, 2005)
[57] http://www.globalenergyinc.com/920202.html.
[58] E.g., Naomi Oreskes, *The Scientific Consensus on Climate Change,* 306 Science 1686 (Dec. 3, 2004)
[59] Major Environmental Aspects, 1-27, Table 1-8.
[60] Neville Holt, *IGCC Technology Status, Economics and Needs*, Presentation to International Energy Agency Zero Emission Technologies (ZET) Technical Workshop, 20 (Feb. 17, 2004).

life of the plant, which can be 40 to 60 years or more. From this perspective, use of IGCC technology becomes not just preferable, but essential for *all* future coal-fired plants.

ii. Water Use and Wastewater

IGCC plants use substantially less water than conventional PC plants. DOE states that IGCC plants typically consume 6 to 9 gallons per minute ("gpm") of water per MW, compared to 10 to 11 gpm for PC plants, or approximately one-half to two-thirds the water use of a PC plant.[61] This factor is particularly significant for the Longleaf Energy Station in light of the water stresses facing the lower Chattahoochee River where the plant is to be sited. In addition, IGCC plants produce 30-50% less wastewater than PC plants.[62]

iii. Solid Waste

IGCC plants typically produce 30-50% less solid waste than PC plants.[63] Also, most of the waste from an IGCC plant is vitrified, thereby-reducing solid-waste disposal issues.[64]

iv. Mercury

Mercury removal rates of greater than 90% can easily be achieved with IGCC using currently available control technologies. DOE states "an IGCC power plant has the potential of achieving very high mercury removal performance with established technology" and "mercury removal in an IGCC power plant can be expected to be very high in removal effectiveness, low in cost, and reliable in design."[65] EPA's January 30, 2004 proposed MACT rulemaking found that carbon bed technology is an available mercury control technology for IGCC power plants and that 90-95% mercury control can be achieved.[66] In addition, "the cost of removal of mercury by a carbon bed in an IGCC plant is lower than in a pulverized coal (PC) plant."[67] The DOE estimates the total cost of carbon bed technology to reduce mercury emissions by 90% or more at an IGCC plant is $0.254 per megawatt-hour, compared to $3.10 per MWh at a PC plant.[68]

Comparison of mercury emissions levels at the proposed Taylorville Energy Center IGCC plant to those proposed by LS Power confirms IGCC's advantage: The Taylorville plant proposes a limit of 0.394 lb/trillion Btu,[69] while LS Power proposes

[61] Major Environmental Aspects, 2-57, 2-61,
[62] Major Environmental Aspects, 1-28.
[63] Major Environmental Aspects, 1-28.
[64] Major Environmental Aspects, 2-63 to 2-64.
[65] US DOE, NETL, The Cost of Mercury Removal in an IGCC Plant, 1 (Sept. 2002).
[66] 69 Fed. Reg. 4676-77 (Jan. 30, 2004),
[67] US DOE, *supra* n. 64, at 2.
[68] Id.
[69] Taylorville Application, 5-10.

limits of 0.68 and 2.2 lb/trillion Btu for CAPP and PRB coal, respectively.[70] Again using the assumptions in Table 2, this results in at least .0125 tons per year, or 25 pounds, lower emissions of mercury using IGCC.

v. Other Pollutants

In its Application, LS Power identified and quantified its proposed emissions of several other pollutants. Again, the Taylorville plant has significantly lower emissions for each.

Table 3: Emissions Levels for Selected Other Pollutants

	Sulfuric Acid Mist (lb/MMBtu)	Beryllium (lb/MMBtu)	Hydrogen Fluoride (lb/MMBtu)
Taylorville Energy Center[71]	0.0026 (3-hr avg)	2.00×10^{-7}	3.00×10^{-5}
Longleaf Energy Station[72]	0.005 (3-hr avg)	4.3×10^{-6} (CAPP); 2.1×10^{-6} (PRB)	0.0031 (CAPP); 0.0024 (PRB)

Once again using the assumptions in Table 2, this results in at least 222 tons per year lower emissions of these pollutants using IGCC (119 of sulfuric acid mist, .08 of beryllium, and 104 of hydrogen fluoride).

c. Economic Impacts

IGCC is also economically achievable. The NSR Manual makes clear how the BACT financial analysis should be conducted:

> Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis. Cost effectiveness, is the dollars per ton of pollutant emissions reduced. Incremental cost is the cost per ton reduced and should be considered in conjunction with total average effectiveness.
>
> In the economical impacts analysis, primary consideration should be given to quantifying the cost of control and not the economic situation of the individual source. Consequently, applicants generally should not propose elimination of control alternatives on the basis of economic parameters that provide an indication of the affordability of a control alternative relative to

[70] Letter from Kathy French, LS Power, to Heather Abrams, GAEPD, 9-10 (July 11, 2005).
[71] Taylorville Application, 4-16, 5-10.
[72] French, *supra* n. 69, at 9-10.

> the source. BACT is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought.[73]

In dismissing IGCC, LS Power did not apply the correct standard. LS Power addressed only the cost per kilowatt (i.e., cost to produce electricity) of IGCC and PC plants and did not address costs per ton of pollutants removed.[74] Either analysis done correctly, however, would show that IGCC is competitive.

1. Cost of Electricity

In its IGCC Appendix, LS Power states that IGCC plants cost more to construct, citing several estimates. The most recent and apparently most comprehensive is a February 2004 study by the John F. Kennedy School of Government, which says PC plant costs range from $1,022 to $1,154 per kilowatt (with an outlier of $1,415); IGCC costs range from $1,070 to $1,876 per kilowatt without redundant gasifiers and from $1,160 to $1,670 per kilowatt with redundant gasifiers.[75]

Other studies belie this cost difference. The power industry research organization, EPRI, estimates the cost of electricity for a 500 MW conventional coal plant at 46.6/MWh and for an IGCC between $45.8/MWh and $48.3/MWh, using Pittsburgh # 8 bituminous coal.[76] The lowest cost estimate suggests that an IGCC plant might cost less than a conventional coal plant. A more conservative treatment would suggest an IGCC plant could cost an additional $1.7/MWh. In a more recent presentation, Edward Lowe of GE Energy estimates the cost of energy without carbon capture for a PC plant at 5.64 ¢/kWh versus 5.66 ¢/kWh for GE's nominal 630 MW reference IGCC plant, a negligible difference.[77] And AEP has estimated the total levelized cost of an IGCC plant at $56.2/MWh and a PC plant at $52.2/MWh, again essentially a negligible difference.[78] These more recent lower figures likely reflect the evolving nature of the IGCC technology, further emphasizing LS Power's need to update its analysis.

Even assuming the difference in cost of electricity were a valid consideration, the cost difference between an IGCC plant and a PC plant would be within the range that is acceptable for a BACT analysis. As the NSR Manual notes:

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[73] NSR Manual, B.31.
[74] Longleaf Application, Appendix J, 4-5.
[75] Id.
[76] Dolt, supra n. 59, at 16.
[77] Edward Lowe, GE Energy, *GE's Gasification Developments,* Presentation to Gasification Technologies Council, 13 (Oct. 10, 2005).
[78] Direct Testimony of Bruce H. Braine on Behalf of Columbus Southern Power Co. & Ohio Power Co., In re: Application of Columbus Southern Power Co. & Ohio Power Co. for Authority to Recover Costs Associated with the Construction & Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility, Case No. 05-376-EL-UNC, 17 (Ohio P.U.C., May 5, 2005).

> The final decision regarding the reasonableness of calculated cost effectiveness values will be made by the review authority considering previous regulatory decisions. Study cost estimates used in BACT are typically accurate to ± 20 to 30 percent. Therefore, control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options.[79]

Under all but the Kennedy School analysis, the cost differences are well within EPA's suggested range of indistinguishability. For instance, under EPRI's worst-case scenario, the cost of an IGCC plant is only about 3.6% higher than that of a PC plant, and AEP's cost difference is about 7.7%. Even the Kennedy School's analysis shows that plants at the high end of the PC range cost essentially the same as those in the low end of the IGCC range. Moreover, the costs for IGCC plants may be overstated, as federal tax credits or other incentives may be available for these plants.[80] Thus, even without IGCC's pollution control benefits, it would be competitive.

2. Cost per Ton Removed

Properly done, the BACT analysis must consider average cost/ton of pollutant removed, and where appropriate, incremental cost/ton of pollutant removed.[81] Using the assumptions in Table 2, *supra*, the additional $1.70/MWh cost for IGCC in EPRI's worst-case scenario would result in an annual cost difference between IGCC and PC at the Longleaf site of $15.2 million,[82] or an incremental, cost of about $1,187 per ton of pollutant removed.[83] Even AEP's difference of $4/MWh results in an incremental cost of $2,793 per ton of pollutant removed.[84] These estimates are extremely cost effective by recent standards.[85]

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[79] NSR Manual, B.44.
[80] *See, e.g.,* IRS News Release (Feb. 21, 2006) available at http//www.IRS.gov/newsroom.
[81] NSR Manual, B.31.
[82] Computed as 8,935,200 MWh * $1.70/MWh = $15,189,840.
[83] Computed as $15,189,840 / 12,795 tons = $1,187.17.
[84] Computed as 8,935,200 MWh * $4.00/MWh / 12,795 tons = $2,793.34.
[85] For instance, the Bay Area Air Quality Management District in California has adopted guidelines for the maximum cost per ton of air pollutants controlled that would be considered cost-effective, ranging from $5,300/ton for PM to $18,300/ton for SO_2. *See* http://www.baaqmd.gov/pmt/bactworkbook/intro3.htm. In his approval of new PM and ozone standards, President Clinton noted that "the EPA will encourage the States to design strategies for attaining the ... standards that focus on getting low cost reductions and limiting the cost of control to under $10,000 per ton for all sources." 62 Fed. Reg. 38,421, 38,429 (July 18, 1997). And, in its recent NSPS rule for electric utility steam generating units, EPA chose a PM standard with an incremental cost over the next-most-stringent option of $8,400/ton. 70 Fed. Reg. 9706, 9715 (Feb. 28, 2005) (proposed rule; finalized with same standard at 71 Fed. Reg. 9866 (Feb. 27, 2006)). Each of these cost-effective figures is substantially more expensive than the cost per ton for IGCC.

3. Greenhouse Gas Cost Considerations

The economic viability of IGCC becomes even more obvious when the likelihood of a carbon-constrained world is considered. Although CO_2 emissions are not currently regulated, it is likely that reductions of CO_2 emissions from power plants will be required soon. Assuming that to be the case, IGCC becomes the hands-down economic winner. As noted above, EPRI estimates the cost of electricity with CO_2 capture and sequestration at $814/MWh less for IGCC than for conventional PC plants.[86] DOE states that "[i]ncluding CO_2 capture, the overall cost of electricity (COE) of the IGCC plant is shown to be about 6.3 ¢/kWh versus 7.9 ¢/kWh for the PC plant."[87] And Edward Lowe of GE Energy estimates the cost of energy with carbon capture to be 6.90 ¢/kWh for GE's reference IGCC plant, compared to 8.29 ¢/kWh for a PC plant.[88] The economic advantage of IGCC is obvious.

4. Reliability

LS Power has also raised concerns about the reliability of IGCC plants.[89] Recent experience shows these concerns to be unfounded. The availability of the Polk plant in 2001 was 84.2% and for the Wabash plant in 2000 was 85%, levels close to those of conventional PC plants.[90] Moreover, IGCC units can be constructed with multiple gasifiers to achieve unit availability at levels comparable to those of conventional facilities. ChevronTexaco (now GE) claims that its Standard Project Initiative Reference IGCC Plant achieves greater than 90% availability by using multiple gas trains.[91] The Eastman Chemical plant in Kingsport, Tennessee, has used a dual-gasifier design to produce chemicals from syngas and has experienced 98 percent availability since 1986.[92] For a 1200 MW IGCC plant, availability_ should be even higher. A 1200 MW plant would consist of multiple turbine trains each fed by a gasifier; additional spare gasifiers would have a relatively low incremental cost and should be easily affordable.

Response: Please refer to Comment 45 of this Final Determination for more information on this topic.

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[86] Holt, *supra* n. 59, at 20.
[87] Major Environmental Aspects, ES-8.
[88] Lowe, *supra* n. 76, at 13.
[89] Longleaf Application, Appendix J, 3-4.
[90] Major Environmental Aspects, 1-26, Table 1-7.
[91] O'Keefe & Sturm, *supra* n. 21, at 30-32.
[92] R.G. Smith, "Eastman Chemical Plant Kingsport Plant Chemicals from Coal Operations, 1983-2000," Presentation to 2000 Gasification Technologies Conference, 5 (Oct. 2000).

47. Federal and Georgia Law Require Consideration of the Supercritical Boiler as BACT.

The Preliminary Determination for the Longleaf Energy Station itself says that "The state-of-the-art "conventional" coal-fired power plant today is the supercritical pulverized coal (SCPC) unit, yet use of this technology was not considered in any of the BACT analyses. As with IGCC, this technology should have been considered as an alternative process for each pollutant for which a BACT determination was required.

Response: Please refer to Comments 1 of this Final Determination for more information on this topic.

48. SO_2 BACT

The BACT determination for SO_2 was defective for the following reasons:

EPD failed to follow its own procedures in establishing BACT as described in the PD[93], leading to an errant proposed determination of BACT for SO_2.

EPD also erred by failing to properly consider IGCC.[94]

Response: After an initial review of the Application, EPD concluded that LEA's proposed SO_2 BACT emission limits of 0.12 lb/MMBtu for Power River Basin subbituminous (PRB) coal and 0.16 lb/MMBtu for Central Appalachian (CAPP) bituminous coal did not represent acceptable BACT levels. EPD requested that LEA submit a tiered SO_2 BACT emission limit that was similar to the limit that had been recently approved by the Nevada Division of Environmental Protection. LEA provided the updated SO_2 BACT analysis requested by EPD.[95] These updated BACT emissions limits, which were reviewed and ultimately included in the draft permit, demonstrate a reduction from LEA's original proposal.[96] EPD therefore did not ignore its own procedures in establishing BACT for SO_2. Quite to the contrary, EPD carefully considered a variety of control technologies and accepted LEA's proposed dry scrubber configuration as BACT only after determining that its environmental and economic advantages rendered it the best control technology for the Facility.

Please also see Comment 45 of this Final Determination for more information on IGCC.

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[93] PD, at 8.
[94] *See* generally the discussion of IGCC above.
[95] Letter from LEA to EPD, February 22, 2006.
[96] The 24-hour limit is 0.12 lb/MMBtu for both PRB and CAPP coal. The 30-day rolling average for most PRB coals (< 1.0 lb SO2/MMBtu) is now 0.065 lb/MMBtu, while that same average for most CAPP coal is 0.105 lb/MMBtu. PD at 63.

> EPD also failed to consider the impact of selection of a boiler technology in selecting technically feasible control options. A supercritical boiler is clearly an inherently less polluting technology in comparison to a sub-critical boiler in that, due to the higher thermal efficiency of a supercritical boiler, it produces more electrical power for the amount of coal burned. This means that on an hourly basis and annual basis, the supercritical boiler is expected to produce less pollution than a subcritical boiler generating the same amount of electricity. In order to accurately compare the emissions from IGCC, subcritical, supercritical and ultra-supercritical technologies for generating electricity from the combustion of coal, BACT should also be listed in terms of pounds per gross megawatt hour (lbs/MW-hr) as well as lbs/MMBtu. The Taylorsville Energy IGCC project discussed above had an SO_2 BACT determination of 0.0117 lbs/MMBtu, translating to approximately 0.082 lb/GMW-hr.

Response: Please refer to Comment 1 of this Final Determination for more information on this topic.

> The top-down BACT analysis is flawed and incomplete because it fails to include the necessary information to fully and properly evaluate the performance of the selected technologies. The most efficient combustion technology (e.g., IGCC) must be evaluated in conjunction with the cleanest fuel (including cleaned coal) and the best performing post control technology in order to correctly determine a BACT hierarchy. The selection of a scrubber technology that will have implications on control of other pollutants (although each pollutant's control must be considered separately under BACT) and cannot be done in the abbreviated and predetermined manner EPD has accepted from LS Power. The top-down BACT process defines Step 3[97] as involving preparation of a list that includes control efficiencies (percent pollutant removed), expected emissions rates (tons per year, pounds per hour), and expected emissions reduction (tons per year) as well as energy, environmental and economic impacts of different technologies and combinations of technologies. This failure led to errant proposed BACT determinations by EPD and errant determinations of control efficiencies, costs and other impacts. In addition, EPD proposes 4 different emissions limitations for SO_2. Since Georgia uses the federal definition of BACT as an emissions limitation, this means that EPD seems to have set four different standards as BACT. Because the input fuel is a component of the BACT determination, this approach is obviously flawed.

[97] NSR Manual, Section II.C.

Response: First, as a *state* agency with an EPA-approved state implementation plan, EPD is not bound by *federal* government's suggested BACT procedure in the Draft NSR Manual.[98] Second, even if the Draft NSR Manual were binding on EPD, no agency is required to strictly adhere to its procedures. As the EAB has held, "the NSR Manual is not a binding Agency regulation and, as such, strict application of the methodology described in the NSR Manual is not mandatory."[99] Third, prior Georgia administrative decisions have held that EPA's interpretations, guidance or other pronouncements have no legally binding effect on EPD.[100]

While strict adherence to the Draft NSR Manual is not required, the BACT analyses submitted by LEA did in fact contain each of the elements identified in Step 3. For example, the Application did not contain all of the Step 3 elements, but the supplemental information provided to EPD did contain the remainder of information identified above.[101] Additionally, the information the Georgia Center claims is lacking can also be found in EPD's analysis of Step 4 of the top-down method. The specific location of the information Georgia Center claims is missing is listed as follows:

- The control efficiencies (percent pollutant removed) were identified in Step 3 on (i) page 21 of Appendix D of the Application in Tables D.3. and D.4 and (ii) Table D.3 of Appendix Da and Table D.4 of Appendix Db filed as part of the August 15, 2005, LEA letter to Ms. Heather Abrams.

- The expected emissions rates (tons per year, pounds per hour) were identified for the top and the selected control technologies in Tables D.5 and D.6 of the Application and Tables D.5 and D.6 of Appendices Da and Db of the August 15, 2005, letter.

- Expected emissions reduction can be calculated from the information provided in Appendix D Tables D.5 and D.6 and was explicitly identified for the differences between wet and dry scrubbing in Tables D.6 of Appendices Da and Db of the August 15, 2005, letter.

- Energy impacts were discussed in the Appendix D text on pages 22 and 23 and in the Appendix Da and Db text as well. Additionally, they were listed out as a specific line in Table 6 of Appendices Da and Db of the August 15, 2005, letter.

- Environmental impacts were discussed as part of the Appendix D text at page 22 and 23 and in Appendices Da and Db.

- Water usage, which is a form of environmental impacts, was detailed in Table D.7 of Appendices D, Da, and Db.

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[98] *See In re: Olin Corporation*, No. DNR-EPD-HW-AH 4-92, 1993 WL 303303, at *1.
[99] In *re: Prairie State Generating Company*, 13 EAD __, slip op. at 16 (EAB 2006).
[100] *See In re: Olin Corporation*, at fn. 12, *supra*.
[101] Letter from LEA to EPD, August 15, 2005

- Economic impacts were identified in Tables D.5 and D.6 of Appendix D and Tables D.5 and D.6 of Appendices Da and Db.

In sum, even if strict adherence to the Draft NSR Manual were required, EPD has included all of the necessary information for a thorough Draft NSR Manual-top-down BACT analysis.

Georgia Center also contends that the BACT analysis is flawed because it identifies different emission limits for SO_2. However, Georgia Center has failed to cite any federal or state law or regulation that prohibits the use of multiple emissions limits for a single pollutant.

Multiple emissions limits compensate for the varying sulfur content within a particular type of coal. For example, the USGS CoalQual database lists the fuel sulfur content for PRB coal to range from 0% to 6.4%.[102] EPD chose its tiered BACT limit in order to account for the natural variation of sulfur content in the fuel and to allow for fuel flexibility for reasons highlighted by LEA in the application process. By using a tiered BACT emission limit, a high level of SO_2 control is achieved regardless of the sulfur content of the fuel. A single emission limit is not as demanding, since at lower fuel sulfur levels a lower removal efficiency is necessary to meet the permit limit.

For the foregoing reasons, EPD's use of a tiered emissions limit for SO_2 is not "obviously flawed." Instead, it constitutes a more stringent SO_2 control mechanism. This mechanism will ensure the maximum level of SO_2 reduction is achieved for the various coal types and sulfur contents in the fuel proposed at the Facility, and it will better serve to ensure the lowest reasonable levels of SO_2 emissions.

> EPD arbitrarily rejected the highest performing end-of-pipe technology (Wet Scrubber) without proper evaluation. In addition, a variety of units have been installed that combine control technologies that can overcome traditional shortcomings of traditional single SO_2 control technologies. The rejection of the wet scrubber is flawed because the collateral impacts analysis is flawed. A technology identified as superior cannot be rejected unless a defect at the site is the basis for rejection. EPD acknowledges that wet scrubbing is superior to dry, and wet scrubbing has been chose as BACT all over the country. Yet, EPD identified nothing site-specific that would justify the choice of dry scrubbing over wet. EPD reports that water consumption is increased.[103] While water is not an unlimited resource, consideration and comparisons to the Roundup permit in and Montana are inappropriate. The determinant in economic consideration is comparison with the burden that other similar facilities have had to bear in controlling their emissions. A cost effectiveness of $761/ton of SO_2 controlled is not an excessive burden nor a basis for rejecting wet scrubbing as BACT.

[102] http://energy.er.usgs.gov/products/databases/CoalQual/index.htm
[103] PD, at 52.

Response: EPD rejected a wet scrubber in favor of a dry scrubber for a variety of reasons, all of which are valid according to the Draft NSR Manual. Contrary to Georgia Center's suggestion, economic considerations were not the sole reason EPD rejected wet scrubber technology as BACT. EPD's initial evaluation of that 5-step determination for SO_2 found that additional information was required to complete the evaluation. EPD's June 10, 2005, letter requested that LEA submit additional information and separate BACT analyses for PRB coal and CAPP coal.[104] LEA complied with this request in its August 15, 2005, letter, providing separate BACT analyses in Appendices Da and Db. Thus, EPD did indeed perform a thorough review and evaluation of LEA's 5-step determination, the standard methodology for BACT determinations.

Additionally, the site-specific considerations EPD presented in pages 43 to 63 of the PD demonstrates that EPD conducted a sufficient BACT analysis. In the PD, the basis for EPD's determination is summarized on page 52 as "the most effective control technology, wet scrubber, is rejected because of increased water consumption, excessive economic impacts and lower ability to control HAP and sulfuric acid emissions."

> Furthermore, assertions about control of Hazardous Air Pollutants ("HAPs") are seriously misleading. This assertion is based on the BACT analysis for hydrogen fluoride (HF).
>
> The case that LS Power has made for the superiority of dry scrubbing over wet scrubbing is based entirely on a few limited data points from EPA's "Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units Final Report to Congress", February 1998. On page 51 of the Preliminary Determination, EPD asserts that 230 tons less HAP as HF will be emitted by the dry scrubber system because of interactions between the fly ash and the HF in the baghouse. This is based on the assertion in the HF BACT analysis that the dry scrubber will control 95% of HF and the wet scrubber 44%.[105] However, this is inaccurate and misleading. This EPA reference is based on comparing a wet scrubber with an ESP to a dry scrubber with a baghouse,[106] in spite of the assertion by LS Power that it is the baghouse that achieves the effect of control. As the Longleaf Energy Station is proposed with a baghouse and a wet scrubber, the control of HF should be equivalent or better with the wet scrubber at Longleaf than for the dry scrubber.

[104] Letter from Ms. Heather Abrams to LEA, June 10, 2005.
[105] PD, at 102.
[106] http://www.icci.org/99final/devito2.htm

Response: Because control of HF and HCl emissions has only recently been scrutinized, there is not a significant amount of information available on HF and HCl removal rates. Additionally, Georgia Center has presented no data to support its claims or counter the data presented by LEA. Importantly the data LEA presented relating to control of HF emissions was only one of many environmental considerations that supported the selection of a dry scrubber as BACT over a wet scrubber. These other considerations have previously been discussed. Thus, the dry versus wet scrubber analysis was not entirely based on the improvement in HAPs control, and EPD's proposed permit action is both well-reasoned and supported by the available facts.

When used in a dry scrubber system, the baghouse captures both the calcium sulfite/sulfate mixture and the fly ash, and its bags become laden with the calcium sulfite/sulfate mixture. It is the calcium sulfite/sulfate mixture which will attract and neutralize the acidic HF gas in the flue gas. A wet scrubber is configured differently. In a wet scrubber configuration, the baghouse (or ESP) is located upstream of the scrubber. Because of this, the bags are only coated with the fly ash which, depending on the calcium content of the coal, may not produce the same neutralizing capability to remove the HF gas as is produced in the dry scrubber system.

> For control of sulfuric acid mist (SAM), the wet scrubber with wet ESP is superior to the dry scrubber. As this option is not properly evaluated, it is incorrect to cite this as a basis for selection of the dry scrubber over the wet scrubber.

Response: LEA did evaluate the option of a wet scrubber with WESP for SAM or H_2SO_4 control.[107] However, because a WESP does not control SO_2 emissions, the WESP was not evaluated as part of the SO_2 BACT. Since sulfuric acid mist emissions are collateral environmental impacts, which are supposed to be evaluated as part of the BACT selection process,[108] it is relevant to discuss the differences between those emissions as part of the SO_2 BACT analysis for wet and dry scrubbing.

However, a facility installing a wet scrubber may or may not install a WESP. That decision would be driven by the BACT analysis for H_2SO_4. When low sulfur coal is used with a wet scrubber, a WESP has not been found to be BACT (e.g., CPS – San Antonio Spruce Unit 2, Intermountain Power Partners Unit 3). Therefore, it is entirely appropriate for a facility not to evaluate a wet scrubber/WESP combination for H_2SO_4 within the SO_2 BACT analysis.

> EPD should also be aware of the following: currently SO_2 emission level limits in Japan are set at 10 ppm, which is available from several wet scrubbing systems. Spray dryers are currently restricted to limited periods of operation at outlet SO_2 emission of approximately 25 ppm. The SO_2 limits being set in Japan have demonstrated awareness of lower emission limits for NO_x, in Europe and will likely eventually push for US coal plants to meet $S0_2$ limits at least as stringent as

[107] See the Application, Appendix D, 38-43
[108] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.26.

those established in Japan. We believe this situation will be the driving force that will likely eventually push the flue gas de-sulfurization industry to more frequent use of wet scrubbing systems for PRB-fueled projects.

EPA has recognized that new state-of-the art wet scrubbers "have been demonstrated above 98 percent."[109] Even "[e]xisting wet FGD systems ... installed in the past 10 years, are capable of consistently achieving SO_2 removal efficiencies of 95 percent and higher."[110] Multiple plants have demonstrated that 95 percent and higher control is achievable on a long-term basis with a wet scrubber, as opposed to lower $S0_2$ removal efficiencies for existing dry injection systems.[111] When EPA recently issued a draft PSD permit for two 750 MW supercritical pulverized coal boilers burning subbituminous coal, it established BACT based on the superior control of a wet scrubber.[112] EPA's independent analysis of available control technologies for pulverized coal fired boilers included reviewing the DOE/NETL (National Energy Technology Laboratory) database, EPA's RACT/BACT/LAER Clearinghouse, EPA's National Coal BACT Workgroup database, and the EPA spreadsheet of recently permitted and proposed coal-fired power plants as well as other sources.

Experience at existing units burning low sulfur subbituminous coal and using wet scrubbers also demonstrates that they consistently achieve SO_2 emission rates much lower than the various limits proposed for Longleaf. The Navajo plant in Arizona uses a wet scrubber and experiences $S0_2$ emission rates of approximately 0.05 lb $S0_2$/MBtu on a 30 day average and 0.04 lb $S0_2$/MBtu on a 365 day average. In 2005, the most, recent year for which data is available, Navaho Unit 1 averaged 0.040 lb/MMBtu and Unit 2 averaged 0.033 lb/MMBtu. The highest 30-day average at Navajo, over 18 months of continuous emission monitor (CEM) data, was 0.063 lb/MMBtu. This experience at Navajo includes all hours of operation, including startup, shutdown and malfunction.

Response: EPD nor LEA have not been able to obtain or independently verify these Japanese results cited by Georgia Center. It appears, however, that the system referenced by Georgia Center is the Chiyoda, which is discussed in more detail below. The Navajo plant data presented by Georgia Center to demonstrate why a dry scrubber is not BACT is not complete, therefore difficult to draw any conclusions from. The data presented by Georgia Center does not provide the removal efficiency, which based on the average fuel SO_2 content from 2001 FERC data for the Navajo plant,[113] would be roughly 95.9% to 96.6% with a minimum of 93.5% for the high. Thus, the wet scrubber is only achieving marginally better <u>actual</u> emissions than the LEA Facility will be permitted to emit since

[109] Standards of Performance for Electric Generating Units for Which Construction is Commenced After September 18, 1978, 70 Fed. Reg. 9706, 9711 (Feb. 28, 2005).
[110] *Id.* at 9715.
[111] *Id.* at 9711.
[112] U.S. EPA, Desert Rock Energy Center (AZP 04-01) Proposed Permit Conditions.
[113] FERC EIA 423 data, http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html

the minimum removal for the LEA Facility using the tiered limit is approximately 92.5%. A margin of compliance is appropriate to accommodate a source's natural fluctuation in emissions levels.

> While all of these sources correctly recognize wet scrubbing as more effective at controlling $S0_2$ than dry scrubbing, many underestimate the control efficiency achievable with wet scrubbing. Certain types of advanced wet scrubbers, particularly a jet bubbling reactor or magnesium enhanced lime scrubber, can achieve 99 percent or: greater $S0_2$ removal. Documented experience at the Mitchell Station in Pennsylvania demonstrates that magnesium enhanced lime, a type of wet scrubbing, regularly achieves 99% control of $S0_2$. It has also been achieved at several coal-fired power plants in Japan and is proposed for several U.S. coal fired power plants. Chiyoda's bubbling jet reactor (a type of wet FGD) has consistently achieved >99% $S0_2$ removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb S02/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis, which is the applicable SO_2 emission limit in Japan. This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan. It also has been demonstrated in the U.S. at the University of Illinois's Abbott power plant and Georgia Power's Plant Yates and recently was licensed for use on several additional plants in the US, including Plant Bowen in Georgia, Dayton Power & Light's Killen and Stuart plants, and AEP's Big Sandy Unit 2,. Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others. Black & Veatch and Southern Company are both U.S. licensees. Mitsubishi, a vendor of scrubber systems, reports it has guaranteed $S0_2$ removal efficiencies up to 99.8 percent, including four coal-fired boilers.

Response: Georgia Center also suggests that there are two other more advanced wet scrubber options — a jet bubbling reactor or a magnesium-enhanced lime scrubber — available which could provide a higher removal efficiency. The magnesium enhanced lime wet scrubber was discussed as part of LEA's BACT analysis and rejected in step 2.[114] For the other technology suggested, the Chiyoda. Georgia Center states that the Chiyoda has been in use "long-term" but has not provided any documentation on the meaning of that phrase. In addition, Georgia Center fails to present any evidence that the limits at Chiyoda have been achieved over the entire duration of its operation, as required under the correct interpretation of "maximum degree of reduction". Further, Georgia Center fails to provide evidence that the 99% reduction would be applicable on all coals, including low sulfur coal. Thus, based on the information provided, the Chiyoda has not been demonstrated at a source similar to the Facility and thus cannot be considered BACT. Finally, there is no evidence regarding the economic and environmental costs that accompany a project like Chiyoda.

[114] See the Application, Appendix D, page 18.

As mentioned above, a top-ranked control option, in this case a wet FGD, cannot be rejected merely because it costs more, in absolute terms, than the less-effective dry FGD. Rather, a top control option can only be rejected for economic reasons if an applicant can demonstrate that the cost-effectiveness (i.e., dollars per ton of pollutant removed) is above the levels experienced by other sources.[115] "[T]he presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a source category may be borne by another source of the same source category."[116] In this case, to avoid setting the $S0_2$ BACT limit based on the better control achievable with a wet scrubber, the Developers would have to provide "a comprehensive demonstration, based on objective factors," that the cost of wet scrubbing is "disproportionately high" and "significantly beyond the range of recent costs normally associated with BACT for the type of facility."[117]

In addition, incremental cost effectiveness should only be used in "certain limited circumstances" to reject a top-ranked control option.[118] This is because incremental cost effectiveness distorts the actual cost of control and results in a false "impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs."[119] This is such a case—the incremental cost of wet scrubbing could distort the cost analysis since wet scrubbing is well within the "normal range" for BACT costs.

Furthermore even if a dry scrubber were selected as BACT, the emissions limitations contained in the Preliminary Determination are not BACT. Four different emissions limitations cannot all be the maximum degree of reduction as required for BACT. The levels of performance are less than are being achieved by existing plants. See the table below:

[115] NSR Manual at B.31.
[116] NSR Manual at B.29; see also Steel Dynamics, 9 E.A.D, at 202; Masonite Corp., 5 E.A.D, at 564 (a control option is economically achievable if the cost-effectiveness is within the range being borne by other sources).
[117] NSR Manual at B.31, B.45 (emphasis added); see also Letter from Robert B. Miller, Chief Permits and Grants Section, USEPA, to Lynn Fiedler, Supervisor Permit Section, Michigan Department of Environmental Quality at 3 (October 6, 1999) ("where controls have been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the controls on those sources and the particular source under review").
[118] NSR Manual at B.31-B.32.
[119] NSR Manual at B.45-B.46.

Table 4

FACILITY NAME	STATE	UNIT ID	UNIT TYPE INFO	SO2 CONTROL INFO	OPERATING HOURS	SO2 MASS	SO2 RATE	HEAT INPUT
Stanton	ND	10	Tangentially-fired	Dry Lime FGD	8,404	139	0.052	5,344,399
Altavista Power Station	VA	2	Stoker	Dry Lime FGD	7,268	61	0.055	2,202,045
Altavista Power Station	VA	1	Stoker	Dry Lime FGD	7,286	60	0.055	2,162,311
Southampton Power Station	VA	2	Stoker	Dry Lime FGD	7,277	74	0.062	2,368,068
Southampton Power Station	VA	1	Stoker	Dry Lime FGD	7,384	75	0.063	2,360,565
Rawhide Energy Station	CO	101	Tangentially-fired	Dry Lime FGD	7,516	876	0.077	22,783,530

Response: In determining BACT, EPD considered energy, environmental, and economic (both average and incremental cost) impacts. EPD did not focus solely on incremental costs as suggested by this comment.

> It should be noted that the type of boiler is irrelevant for scrubber performance. Only the flue gas properties affect the scrubber performance. The flue gas for the boilers above are sufficiently similar that scrubber efficiency is comparable across boiler types. Therefore, even if dry scrubbing were erroneously selected as the top-ranked control option for SO_2, the BACT limit must be between 0.055 lb/MMBtu or less lb/MMBtu, including startup, shutdown, and malfunction, based on the fact that these other plants demonstrated that greater SO_2 reduction is achievable.

Response: To be clear, LEA has two BACT emission limitations, one on a 24-hour basis and a second on a 30-day basis. The 30-day limit has 3 parts to ensure that the dry scrubber is operated at a high level of efficiency at all times, regardless of coal sulfur content levels. The low sulfur coal limit of 0.065 lb/mmBtu that is in the final permit is amongst the lowest limits ever established in a PSD permit. In addition, all the boilers listed in the Table 4 above provided by the commenter would have difficulty complying with a limit of 0.065 lb/mmBtu on a continuous basis. Although the Draft Permit does contain different SO_2 emission rates that correspond to difference circumstances, this condition does not invalidate EPD's BACT determination. In fact, it only serves to further strengthen the emissions limitations, maximize emission reductions and minimize ambient air impacts of SO_2.

49. NOx BACT

The BACT determination for NO_X was defective for the following reasons:

1. EPD Failed to Follow its Own Procedures in Establishing BACT.

EPD failed to follow its own procedures in establishing BACT as described in the. Preliminary Determination,[120] leading to an errant proposed determination of BACT for NO_X.

Response: The PD provides the definition of BACT and requires that the BACT analysis meet two requirements: i) use of a "top-down" procedure using the Draft NSR Manual and ii) the BACT selection is justified in terms of the statutory criteria, supported by the record, and the basis for rejection of any more stringent options is explained.[121]

The BACT for NOx and the resulting PD discussion of the BACT determination meets these criteria and definition. The interpretation of the definition of BACT suggested by the various Georgia Center comments is not in line with various court decisions, guidance, or EPD's policy. When the accepted interpretation is used, the EPD's NOx BACT meets this definition. As for the two criteria: i) first, the BACT was done in a "top-down" manner, generally following the Draft NSR Manual and ii) second, the statutory criteria and basis of the selection is covered by the PD on pages 22 to 37.

2. EPD Failed to Include IGCC as a Technically Feasible Option.

EPD erred by failing to include IGCC among the technically feasible options.[122]

Response: Please refer to Comment 45 of this Final Determination for more information on this topic

3. EPD Failed to Consider the Impact of Selection of Boiler Technology in Selecting Technically Feasible Control Options.

EPD also failed to consider the impact of selection of a boiler technology in selecting technically feasible control options. A supercritical boiler is clearly an inherently less polluting technology in comparison to a sub-critical boiler in that due to the higher thermal efficiency of a supercritical boiler, it produces more electrical power for the amount of coal burned. This means that on an hourly basis and annual basis, the supercritical boiler is expected to produce less pollution than a sub-critical boiler generating the same amount of electricity.[123] In order to accurately compare the emissions from IGCC, subcritical, supercritical and ultra-

[120] PD, at 8.
[121] PD at 9.
[122] *See generally* the discussion of IGCC above.
[123] *See also* Comment #4 below

supercritical technologies for generating electricity from the combustion of coal, BACT should also be listed in terms of pounds per gross megawatt hour (lbs/MW-hr) as well as lbs/MMBtu. The Taylorsville Energy IGCC project discussed above had a NO_X BACT determination of 0.0246 lbs/MMBtu, this translates to approximately 0.17 lb/GMW-hr.

Response: Please refer to Comment 1 of this Final Determination for more information on this topic.

4. The Top-Down BACT analysis is Flawed and Incomplete.

The top-down BACT analysis flawed and incomplete because it fails to include the necessary information to fully and properly evaluate the performance of the selected technologies. For example, SCR is an add-on technology that achieves better than 90% reduction. By only reporting an incomplete list of final emissions rates in lbs/MMBtu as the performance capability of SCR, no accurate determination of the performance of SCR in combination with other inherently less polluting technologies can be achieved. The Top-Down BACT process defines Step 3[124] as involving preparation of a list that includes:

- Control efficiencies (percent pollutant removed),
- Expected emissions rate (tons per year, pounds per hour), and
- Expected emissions reduction (tons per year).

Response: The information that Georgia Center claims EPD failed to consider was, in fact, provided to EPD during the application process. The list of control efficiencies that the Georgia Center alleges to be missing can be found in EPD's discussions of Steps 2 and 3 of the Draft NSR Manual's "top-down" process as well as in the cost analysis table presented to EPD via LEA's February 28, 2006, letter to Ms. Anna Aponte. The expected emissions rate and expected emissions reduction were also provided to EPD in LEA's February 28, 2006, letter to Ms. Aponte.

While EPD did not present tables identical to Tables B-2 and B-3 of the Draft NSR Manual, the material presented in those example tables was considered by EPD. A table similar to Table B-2, which ranks the NO_x control alternatives, appears as Table VIII on page 32 of the PD. Additionally, in response to a request from EPD, LEA provided a table similar to Table B-3 in its February 28, 2006, letter to Ms. Aponte.

Additionally, the PD <u>does</u> contain the ranking to determine most stringent control technology on page 32 in Table VIII. The ranking is based on the range of applicable demonstrated, permitted, or reported emission rates (lb/MMBtu emission limit). The Draft NSR Manual does not require that emission rankings be based on performance level, rather it states "a hierarchy is established that places at the "top" the control

[124] NSR Manual, Section II.C.

technology option that achieves the lowest emission level."[125]

5. EPD Erred by Failing to Properly Consider Controls in Combination.

EPD erred by failing to properly consider controls in combination as required under Step 1 of the Top-Down BACT process.[126] For example, for Hybrid Selective Reduction (HSR), the Preliminary Determination[127] lists control efficiencies of up to 98%. The performance of Low- NO_x burners (LNB) combined with overtire air (OFA) is presented as achieving levels as low as 0.15 lbs/MMBtu.[128] Table VII is incomplete for failing to include consideration of technologies in combination including LNB/OFA combined with HSR that, according to the information supplied in the Preliminary Determination is the "most effective level of control" presented. According to the information in the Preliminary Determination HSR combined with LNB/OFA is BACT at 0.003 lbs/MMBtu. Clearly other combinations including Selective Catalytic Reduction (SCR) and LNB/OFA should be evaluated. Other lower performing emissions levels for these technologies and their economics can be evaluated under the Top-Down BACT process, but the "most effective: level of control" must be evaluated under the Top-Down BACT process.[129]

Response: Step 3 of the top down evaluation stated that LNB/OFA are an integral part of all new boilers. Accordingly, all the other technologies were considered with that as the baseline. The emission rates presented for all other technologies identified are evaluated in combination with LNB/OFA. Thus, EPD did consider, among other combinations, LNB/OFA combined with HSR and LNB/OFA combined with SCR.

Additional Discussion and References for Comment #E5

The term "best available control technology" means "an emission limitation based on the maximum degree of reduction of each pollutant...." The Application and PD contain no evidence that the proposed NO. BACT limit of 0.07 lb/MMBtu is based on the maximum degree of reduction that is achievable. The PD does not contain any ranking of control alternatives comparable to the examples in the NSR Manual in Tables B-2 and B-3. Instead, it contains a chart that ranks control technologies.[130] It picks an emission limit in the middle of the range reported for SCR, but never explains why this mid-range value is NO_x and not the lower end of the range. Further, as explained supra, the range does not encompass levels that are achieved and as explained below, levels that are "achievable."

The PD does not contain the ranking that is required to determine the emission limitation that represents the maximum degree of reduction that is achievable with this technology.

[125] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.25.
[126] NSR Manual, Section IV.A.
[127] PD, at 27.
[128] PD, at 31.
[129] NSR Manual, Section IV.C.2.
[130] PD, Table VIII.

A control alternative requires an emission limit (e.g., ppm, lb/MMBtu, lb/hr) and a performance level (e.g., percent reduction, emission reduction).[131]

> The Application and PD do not include any performance data, required to prepare such rankings, NO_x will be controlled by two technologies in series. First, NO_x will be controlled within the boiler using combustion controls -- low NO_x burners and separated overfire air. These two controls determine how much NO_x exits the boiler, referred to as the boiler outlet NO_x or the "baseline" in the PD. The flue gases from the boiler are then routed to an SCR, located downstream of the boiler. The SCR is a metal frame packed with catalyst. Ammonia is injected into the flue gases and the ammonia and NOx react in the presence of the catalyst to form nitrogen gas and water. This process removes upwards of 90% of the NO_x at the boiler outlet. The degree of NO_x reduction depends upon the amount of NO_x removed by both of these technologies. BACT is the maximum degree of reduction that is achievable by both of these technologies combined. The maximum degree of reduction has not been required.
>
> The PD states that low NO_x burners and staged overfire air would be expected to operate with NO_x emission levels in the range of 0.15 to 0.47 lb/MMBtu.[132] The PD then selects a value at the upper end of the range, 0.30 lb/MMBtu, as the baseline NO_x (boiler outlet) for Longleaf.[133] This is an extraordinarily high value for a supercritical boilers using low NO_x burners and staged overfire air and is not BACT.
>
> Much lower boiler outlet NO_x levels, as low as 0.1 lb/MMBtu, have been achieved for similar sources burning the proposed coals using only combustion controls.[134, 135] The Clean Air Markets NO_x CEMS data includes many units operating at lower boiler outlet levels with the proposed combustion controls, including Scherer Units 3 and 4 in Georgia, Baldwin Unit 3 in Illinois, Labadie Units 1-3 in Missouri, and Rush Island Units 1-2 in Missouri.
>
> These lower boiler outlet NO_x levels, as well as the achieved levels in Table I.1., are for subcritical boilers. Subcritical boilers are not acceptable as BACT. This means that less coal is burned and less NO_X is emitted from a supercritical boiler than a subcritical boiler per megawatt hour of electricity generated.[136] The proposed boiler outlet of 0.30 lb/MMBtu is not credible for a new supercritical

[131] NSR Manual, Sec. IV.C.3.
[132] PD, at 31.
[133] *Id*
[134] Ron von Heim, Reducing NO_x Emissions on a Mid-Western Utility Boiler Firing PRB Coal with Low-NO_x Burners and Overfire Air, PowerGen 2002; R. Lewis, G. Camody, and P. Jennings, Summary of Recent NO_x Achievements with Low NO_x firing Systems and Highly Reactive PRB and Lignite Coal: As Low As 0.10 Lb NO_x /MMBtu
[135] T. Whitfield and others, Comparison of NO_x Emissions Reductions with PRB and Bituminous Coals in 900 MW Tangentially Fired Boilers, 2003 Mega Symposium.
[136] E.S. Sadlon, Alstom, Application of State-of-the-Art Supercritical Boiler Experience to U.S. Coals – Corrosion Consideration, CoalGen 2000.

boiler equipped with low NO_x burners and staged overfire air. Both Babcock and Wilcox and Alstrom Power are offering low- NO_x burner and control packages that can achieve 0.15 lbs/MMBtu in retrofit applications and should achieve higher performance in a new installation such and Longleaf.

The PD does not disclose the assumed SCR NO_x control efficiency. It can be calculated from the proposed boiler outlet (0.30 lb/MMBtu) and the proposed NO_x BACT limit (0.07 lb/MMBtu) and is 77%. In reality, the boiler outlet will be much lower, certainly less than 0.2 lb/MMBtu, and the corresponding SCR control efficiency then will only be 65% or less. Such low NO_x control efficiencies are not the maximum degree of reduction that is achievable with SCR and thus are not BACT.

Modern SCRs routinely achieve NO_x removal efficiencies greater than 90%. Detailed analyses of EPA Clean Air Markets data indicates that "90% removal efficiency is currently being achieved by a significant portion of the coal-fired SCR fleet." Greater than 30 units have achieved greater that 90% NO_x reduction. A level of 90% NO_x removal was achieved on 10,000 MW of coal-fired generation in 2004. Many coal-fired units have been guaranteed to achieve greater than 90% NO_x reduction. The McIlvaine reports, one of the sources the NSR Manual states should be considered in a BACT analysis,[137] indicate three of Haldor Topsoe's SCR installations averaged over 95% NO_x reduction during the 2005 ozone season.

The PD states with no support that such high removal efficiencies for SCRs can only be achieved when the level of NO_x at the inlet to the control device is high. This has been demonstrated to be false in numerous SCR performance tests and in two independent studies of the Clean Air Market CEMS data (SCR systems on PRB fired units [low inlet NO_x] have no greater control or reliability issues compared to bituminous [high inlet NO_x] coals) and Silva and Khan, p. 13 ("these data show that SCR effectiveness was not influenced by the types of coal [and hence inlet NO_x] being fired"). Further, we note that 90% and higher control efficiencies are routinely maintained on gas-fired units that have boiler inlet NO_x values lower than 0.1 lb/MMBtu.

The PD also states with no support that there are physical limitations and secondary effects that limit the practical achievable NO_x reduction level, claiming adverse impacts to the boiler and pollution control equipment. The PD claims, for example, that increased NH3 injection is not "as effective" in reducing NO_x above 80% NO_x control.[138] This is misleading. While there is a limit to the advantageous effect of excess NH3 in removing NO_x, the NO_x control efficiency can be increased using other design measures. The NO_x removal efficiency, for example, can be increased by using a larger volume of catalyst, improving the temperature distribution at the

[137] NSR Manual, p. B.12.
[138] PD, at 32.

face of the catalyst, and improving the mixing of NH3 and flue gases.[139] Further, actual operating experience of SCRs reviewed supra refute this claim. NO_x removal efficiencies greater than about 80% are routinely guaranteed and achieved.

The achievable NO_x emission, limit for the new Longleaf units would be about 0.02 lb/MMBtu, if the boiler outlet NO_x were 0.2 lb/MMBtu (a typical value) and the SCR achieved 90% NO_x control (also typical). Assuming a boiler outlet of 0.30 lb/MMBtu, which would be very high for a new supercritical boilers burning the proposed coals, the achievable NO_x emission limit would be 0.03 lb/MMBtu, less than half of that picked as BACT for Longleaf. Thus, we urge EPD to revisit the NO_x BACT determination. We. also urge EPD to specifically request LNB, SOFA, and SCR design specifications (a copy of the vendor guarantees and if not specified in these guarantees, the boiler vendor, LNB vendor and model, boiler outlet NO_x Ox and CO, SCR NO_x control efficiency, type of catalyst, catalyst pitch, number of catalyst layers, catalyst lifetime, pressure drop, SO_2 to SO_3 conversion rate, etc). This information is essential to determine BACT for both NO_x and sulfuric acid mist, discussed elsewhere in these comments.

[139] K.J. Rogers and P.S. Nolan, SCR Reactor Performance Profiling and Results, 2001 Mega Symposium; S.M. Cho, Properly Apply Selective Catalytic Reduction for NO_x Removal, Chemical Engineering Progress, January 1994, pp. 39-44.

6. The Preliminary Determination is Grossly Deficient in Information on Current Levels of Performance for SCR and LNB/OFA.

EPD erred in accepting LS Power's assertions regarding BACT performance without performing independent research on these claims. The proposed BACT level of 0.07 lbs/MMBtu does not represent the current "most effective level of control" for SCR and LNB/OFA. Furthermore, the assertions of LS Power regarding averaging times for different plants and permit determinations were not investigated. EPA's Acid Rain database provides readily available information that should have been used to look at actual performance under different averaging times for BACT. EPD failed to investigate readily available information and accepted dismissal by LS Power of more stringent BACT determinations and plant performance data and, thereby, failed to determine NO_x BACT for the Longleaf Energy Station. An analysis of Acid Rain data shows that 5 existing units are currently capable of performing at below 0.04 lbs/MMBtu on a 30 day rolling average basis (Ghent 3 and 4 combine in one stack). As these units are SCR LNB/OFA retrofits on units all over 15 years old, performance on a new Greenfield unit such as Longleaf should be better than on these older units

Additional Discussion and References for Comment #E6

The Draft Permit sets a NO_x BACT limit of 0.07 lb/MMBtu based on a 30 day rolling average, achieved using dry low NO_x burners (LNB), staged over-fire air (SOFA), and selective catalytic reduction (SCR).[140] Periods of startup and shutdown are excluded from this limit.[141] The technology selected as BACT – LNB, SOFA, and SCR – is appropriate. However, BACT is an emission limit based on the maximum degree of reduction, The NO_x emission limit is not based on the maximum degree of reduction that is achievable and is far too high to satisfy BACT for new supercritical boilers.

The Preliminary Determination does not explain how the NO_x BACT limit was selected. The PD identifies a number of lower NO_x limits, but does not explain why they do not represent BACT for Longleaf. These include SCR at 0.05 lb/MMBtu in Table VIII, an achieved NO_x rate of 0.056 lb/MMBtu reported at the 2003 Mega Symposium,[142] and a NO_x rate of 0.045 lb/MMBtu achieved at Parish Unit 6.[143] In fact, the PD's analysis is outdated and incomplete. As we explain below, much lower NO_x limits have been achieved, permitted, and guaranteed by vendors.

Title IV of the Clean Air Act requires that subject utilities continuously monitor NO_x emissions from their boilers and report the data quarterly to the U.S. EPA.

[140] Permit, at 8, Condition 2.14(a).
[141] Permit, at 22, Condition 8.22(a)
[142] PD, at 33.
[143] PD, at 34.

This data is uploaded to EPA's Clean Air Markets website.[144] Over 200 of the units included in this database have installed the controls that were identified as BACT for Longleaf – combustion controls and selective catalytic reduction (SCR) to comply with various regulations, most recently the NO_x SIP Call.[145] This data includes continuous average hourly measurements of NO_x, SO_2, heat rate, megawatt output, and other relevant operating parameters. This data set is the largest collection of NO_x data in the world. These data demonstrate the NO_x emission rates that have been achieved in practice at existing units, a much tougher standard than the "achievable" threshold for BACT.

We downloaded the 2004 to 2006 NO_x CEMs data for the best performing units from the EPA website. We calculated 30-day rolling averages from EPA's daily average data for each ozone season for the ozone-season units and for the entire period of record for year-round units. We eliminated days with invalid heat input data and days with less than 24 hours of NO_x data that were preceded or followed by at least one day with zero operating hours (major startups and shutdowns). Startups and shutdowns that lasted less than 24 hours were included in the average, thus overestimating the 30-day rolling average compared to the Permit requirements. The highest 30-day rolling averages are summarized below in Table 5.

[144] http://www.epa.gov/airmarkets/emissions/raw.
[145] 40 CFR 96

Table 5 - Summary of Best Performing Units in the Acid Rain Database

Achieved NOx Emissions (lb/MMBtu)

OZONE SEASON

UNIT	Highest 30-day Ozone Season Rolling Average	
	2004	2005
Ghent CS02	0.063	0.031
Havana 9	NA	0.035
Chesterfield 6	0.054	0.038
Trimble 1	0.045	0.038
Amos CS012	NA	0.047
Colbert 5	0.051	0.047
Mountaineer 1	0.060	0.048
Cardinal 3	0.054	0.050
Pleasants I	NA	0.050
Cardinal 2	0.072	0.052
Ghent 1	0.071	0.052
Pleasants 2	0.046	0.058
Chesterfield 5	0.046	0.059
Bowen 2	0.061	0.061
Cardinal 1	0.088	0.061
Bowen 4	0.058	0.062
Bowen 1	0.066	0.064
Bowen 3	0.055	0.065
Hammond 4	0.066	0.066
Miller Unit 3	0.065	0.068

YEAR ROUND

UNIT	Highest 30-day Rolling Average	Period of Operation
Parish 5	0.057	4/03 - 6/06
Parish 6	0.050	4/03 - 6/06
Parish 7	0.054	3/04 - 6/06
Parish 8	0.050	11/03 - 6/06

These data demonstrate that 30-day rolling average NO_x emission rates much lower than proposed for Longleaf were achieved in 2005 at 20 similar units burning a wide range of coals, from low Sulfur, (Power River Basin - PRB) sub-bituminous coal to high sulfur bituminous coals. These data also demonstrate that most of the units improved their performance in 2005 compared to 2004. Previous analyses of 2002 and 2003 indicate that NO_x emissions have generally decreased over time, in response to regulatory deadlines and as companies have learned how to optimize their combustion controls and SCR.

These results are consistent with similar studies conducted by others. SCR system designers have analyzed EPA's Clean Air Market's CEMS data to determine the NO_x levels that are currently being achieved by over 100 SCR-equipped coal-fired boilers.

This NO_x CEMS data represents a worst-case for the new Longleaf units for three reasons. First, some periods of startups, shutdown, and malfunction are included in the rolling averages reported in Table I.1. These periods would be excluded under the proposed Permit. Second, the NO_x controls on the units in Table I.1. were installed as retrofits on existing units mostly built 30 plus years ago. Retrofit controls must be forced into an existing plant and control NO_x from old boilers. This results in more variable boiler outlet NO_x, higher costs, and more operational constraints than would be experienced for a new facility.[146] For example, one of the most important factors that influence SCR performance is good mixing between injected ammonia and the flue gas. Good mixing can be difficult to achieve at existing plants due to space constraints. Third, the units currently achieving low NO_x emission rates are subcritical boilers. Subcritical boilers should not be accepted as BACT as higher efficiency methods of converting coal to energy provide more protection to human health and the environment.

The PD did not identify several units that have been permitted or issued draft permits that contain much lower NO_x limits. These include:

0.05 lb/MMBtu 24-hr average; Trimble, KY

0.05 lb/MMBtu annual average, Spruce, TX

0.05 lb/MMBtu annual average, other TX draft permits

0.06 lb/MMBtu 24-hr average, Desert Rock, NM

0.067 lb/MMBtu 24-hr average, Newmont, NV

The 24-hour averages, when converted to a 30-day basis, would be even lower. The PD should be revised to explain why these lower NO_x BACT limits do not establish the floor for a BACT determination for Longleaf.

Response: EPD has compiled a list of recently proposed coal-fired power plants, which is attached as part of this Final Determination. The final permit now includes an annual average NOx limit of 0.05 lb/mmBtu in addition to the 30-day NOx limit of 0.07 lb/mmBtu. Adding the new limit of 0.05 lb/mmBtu makes this facility one of the least emitting coal-fired power plants ever permitted in the United States.

[146] Ted Kurtides, Lessons Learned from SCR Reactor Retrofit, Coal-Gen, August 6-8, 2003.

7. LS Power's Attempt to Discredit the value of 0.016 lbs/MMBtu that Babcock and Wilcox Published in 2001 as a Theoretical Value is Incorrect.

LS Power has attempted to discredit the value of 0.016 lbs/MMBtu that Babcock and Wilcox published in 2001 as a theoretical value.[147] Review of other recent technical publications indicates that this value is far from theoretical and is perhaps higher than the current "most effective level of control". Babcock and Wilcox produce the DRB-4Z low NO_x burner that has been achieving 0.15 lbs/MMBtu in retrofit installations.[148] Alstom Power's Ultra-Low NO_x Integrated System is also capable of performing at 0.15 lbs/MMBtu on pulverized coal boilers.[149] A 2002 Babcock Technical Publication titled "SCR Performance at LG&E's Trimble County Generating Station" reports that this retrofit is achieving 0.025 lbs/MMBtu, 91.3% NO_x reduction and less than 0.1 ppm ammonia slip at a retrofit plant. Recent technical papers suggest that interlayer mixing between the catalytic layers of an SCR increases NO_x removal efficiency and reduces ammonia slip allowing for 95% control with less than 2% ammonia slip.[150] Combining 0.15 lbs/MMBtu for LNB/OFA with 95% control for SCR suggests that the "most effective level of control" should be 0.0075 lbs/MMBtu. A more conservative value that discounts the ability to achieve higher levels of NO_x control with low ammonia slip through improved mixing suggests that 0.15 lbs/MMBtu and a conservative 90% control efficiency for SCR would result in 0.015 lbs/MMBtu.

Additional Discussion and References for Comment #E7

Most major SCR vendors currently offer and have offered and provided SCRs guaranteed to achieve 0.03 lb/MMBtu and below for units firing all types of coal. These include Babcock Power, Haldor Topsoe, CERAM, Siemens, and Cormetech.[151] Further, Texas concluded over 5 years ago that a NO_x limit of 0.030 lb/MMBtu "is technically feasible... based on the literature and discussion with SCR vendors." At that time, one utility (Reliant) had awarded a contract to construct SCRs on four coal-fired boilers guaranteed at 0.030 lb/MMBtu (the four Parish Units).[152] As of May 2003, three SCR vendors were "emphatic" that 0.03 lb/MMBtu is "very achievable."[153]

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[147] PD, at 34.
[148] Update of B&W's Low NO_x Burner Experience, July 24, 2000.
[149] Development of an Ultra-Low NO_X Integrated for Pulverized Coal Fired Power Plants.
[150] Interlayer Mixing for Improved SCR Performance", FERco & EPRI May 2006.
[151] *See e.g.,* vendor presentations at the McIlvaine SCR Hot Topic session on October 12, 2006 and vendor guarantees offered for Trimble Unit 2. The Trimble unit will burn a high sulfur, high nitrogen bituminous coal. Voice recording available online to subscribers of McIlvaine Power Plant Knowledge System.
[152] Texas Register, v. 26, no. 2, January 12, 2001, p. 557.[138]Randy Hamilton Notes, November 2004.
[153] Randy Hamilton Notes, November 2004.

The November 2, 2006 McIlvaine Utility E-Alert notes: "Haldor Topsoe reported they have provided catalyst for several installations that consistently run at less than 0.03 lb/MMBtu NO_x."[154] The McIlvaine reports are one of the sources the NSR Manual states should be considered in a BACT analysis.[155]

Response: As stated in the previous response, adding the new NOx limit of 0.05 lb/mmBtu makes this facility one of the least emitting coal-fired power plants ever permitted in the United States. In addition, the commenter's own actual NOx data (most of the "best" units have NOx emissions > 0.05 lb/mmBtu) presented in the previous comment, which shows the lowest emitting coal-fired units in the country, supports EPD's decision to include a NOx BACT limit of 0.05 lb/mmBtu.

50. The Permit Improperly Allows Bypassing during Startup/Shutdown.

The permit improperly allows bypassing of SCR and Lime Spray Tower/Dry Scrubbing during startup and shutdown. As a technical matter, this is unnecessary and should be stricken. These conditions amount to outright exemptions from BACT requirements during startup and shutdown which are clearly not allowed under the Clean Air Act and EPA policy. The emission limits defined as BACT may not include exemptions for excess emissions due to startup or shutdown, or malfunction or maintenance/planned outage for that matter. Emission limits defined as BACT under the PSD program are established under Title I of the Clean Air Act and are intended to be protective of ambient air standards as well as to be technology forcing. The ambient air quality standards are to be met on a continuous basis. Thus compliance with the BACT limits must also be on a continuous basis. Indeed, Section 302(k) of the Clean Air Act expressly defines the term "emission limitation" as a limitation on emissions of air pollutants "on a continuous basis." Section 169(3) of the Clean Air Act, in turn, defines BACT as an "emission limitation." Accordingly, the Clean Air Act mandates that BACT continuously limit emissions of air pollutants. EPA's January 28, 1993 guidance memo entitled "Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD" specifically disallows automatic exemptions from BACT emission limits and instead informs states to use enforcement discretion in determining whether to enforce for violations of BACT emission limits. EPA's policy also indicates that alternative emission limits for startup and shutdown "could effectively shield excess emissions arising from poor operation and maintenance or design, thus precluding attainment."[156] Instead, EPA policy indicates that enforcement discretion is the preferred approach for addressing the occurrence of excess emissions.

Response: Please refer to Comment 11 of this Final Determination for more information on this topic.

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[154] Utility E-Alert 798, November 2, 2006, Hot Topics, Haldor Topsoe Catalyst Efficiency Revisited, at
[155] NSR Manual, p.B.12.
[156] EPA's January 28, 1993 Guidance Memo, at 3.

51. The Permit Fails to Include a BACT Determination for Opacity.

The Preliminary Determination fails to include a BACT determination for opacity. This exclusion is inconsistent with the definition of BACT. Reviewing the definition of BACT, quoted above at page 2, BACT is an emission limit, "including a visible emission standard." Thus for each visible BACT pollutant, EPD should have, through its BACT determination, established a visible emission standard, i.e., an opacity standard, that is reflective of BACT.

Response: First, opacity is typically only associated with PM/PM10 emissions from coal-fired power plants. Second, while opacity is used to gauge PM/PM10 pollutant levels, opacity is not, in and of itself, a Clean Air Act pollutant; BACT, by definition, only applies to Clean Air Act pollutants. A broader citation of the BACT definition than included by Georgia Center provides better context for LEA and EPD's decision: "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the Clean Air] Act …" EPD's and LEA's conclusion that BACT only applies to regulated pollutants is easier to determine from the broader citation and is consistent with determinations made in other states. Opacity is only used as an indicator, when desired, for other pollutants, i.e. PM/PM10, that are subject to BACT. Finally, Longleaf is required to install PM/PM10 continuous emissions monitoring system (CEMS) which will provide a more direct and thus more effective means of monitoring particulate emissions than opacity.

While opacity standards were developed at a time when air pollution control agencies relied upon opacity to limit particulate emissions, the introduction of CEMS technology for PM provides a direct method for agencies and sources to monitor and enforce PM emissions. As its name implies, a CEMS for PM enables a user to monitor PM emissions at all times. Equally important, a CEMS for PM measures particulate emissions and not the degree to which the gases passing by an opacity monitor or visible to the naked eye may tend to obscure or scatter light. As a result, a CEMS for PM is a more consistent and effective means of ensuring that particulate matter emissions do not exceed applicable permitted emission limits. For these reasons, the Federal Register notice accompanying the new NSPS for PM at new electric utility steam generating units provides that "PM CEMS may be used as an alternative method to demonstrate continuous compliance and *as an alternative to opacity* and parameter monitoring requirements." [157] (emphasis added). Although the EPA does not yet require stationary sources to install a CEMS for PM, EPD has required this technology at the Facility.[158] Because the NSPS for boilers (like LEA's), allow the use of a CEMS for PM in lieu of an opacity monitor, and because the CEMS for PM is a direct measure of the PSD-regulated pollutant, monitoring a surrogate parameter (not regulated as a pollutant under the Clean Air Act) would provide not environmental benefit.

[157] 71 Fed. Reg. 38, pages 9867-68 (February 27, 2006).
[158] Draft Permit, Condition 5.2(f).

The Draft Permit prohibits the discharge of any gas from each PC-fired boiler that exhibits "greater than 20 percent opacity."[159] Further, the Draft Permit prohibits the discharge of any gas from the auxiliary boiler that exhibits "greater than 10 percent opacity."[160] Opacity has been accepted by the EAB as being a state-only standard[161] and thus not subject to BACT determinations. No changes have been made to the permit based on this comment.

52. Particulate Matter (PM)

1. PM For Cooling Towers

EPD rejects dry cooling because it asserts that use of this technology will lead to efficiency decreases, causing a 12% energy penalty and higher emissions. EPA's assumptions, however, are incorrect. Use of dry cooling at a new coal plant does not add much capital cost (~5%), has a very moderate annual efficiency penalty of approximately 2 % relative to wet cooling towers, and there is no difference in inside-the-fence plant energy demand. Given the excessive amount of water that is associated with wet cooling here and the fact that wet scrubbing for $S0_2$ was rejected in large part because of the water demands of wet scrubbing, the plant should have been required to install a dry cooling system.[162]

Response: Because of the thermodynamic design basis of a dry cooling system, its operation and effectiveness are highly dependent on the climate specifics of the location where it is installed.

Lastly, although not related to PM emissions from the cooling tower, the Georgia Center states that dry cooling should have been required because of water demands. As part of EPA's investigations for cooling water intake structures, EPA found that dry cooling is not the best technology for new coal-fired power plants.[163] EPA found the costs to be substantially greater than wet cooling options and that dry cooling creates an energy penalty from operation and other non-aquatic impacts.[164] Other site-specific constraints include the amount of area that dry cooling systems occupy. Specifically, one dry cooling unit would occupy an area 200 feet by 500 feet. This space requirement is substantial, especially considering that a minimum of two units would be required for the Facility.

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[159] Draft Permit § 2.14(o).
[160] Draft Permit § 2.15(f).
[161] *In re: Amerada Hess Corp. Port Reading Refinery,* 12 EAD __, 14-16 (EAB 2005).
[162] For more information on the wet versus dry cooling issue, *see:* http://www.energy.ca.gov/pier/conferences+seminars/2005-06_advanced_cooling_conference/papers/H_Powers_Coal_ACC_paper.pdf.
[163] 66 Fed. Reg. 65282-84.
[164] Because of the parasitic load of the dry cooling system, power producers produce more air emissions per kilowatt-hour of energy produced. Nationally, EPA estimated that a minimum requirement based on dry cooling would cause significant air emissions increases over wet cooling systems. *See* 66 Fed. Reg. 65283.

2. Paving of On Site Haul Roads

As part of its BACT determination, EPD should have required the paving of on site haul roads, as travel on unpaved roads causes an increase in particulate matter. As such, S38 and all roads should be paved to reduce PM.[165]

Response: A BACT analysis was completed for haul roads on the site. The result of that analysis concluded that BACT for all haul roads, except for the landfill haul road, should be paving and periodic sweeping/washing of the roads. This represents the highest level of PM/PM_{10} control, and as such, no further evaluation was conducted for other control technologies.

With respect to BACT for the landfill haul road, LEA concluded, and EPD agreed, that BACT would be chemical suppressants and water sprays as necessary. The landfill haul road consists of a relatively short stretch of road running from the edge of the landfill onto the landfill itself. In determining BACT for this section of road, LEA relied upon guidance from EPA. EPA has concluded that paving "is probably most applicable to relatively short stretches of unpaved road <u>with at least several hundred vehicle passes per day</u>."[166] The landfill road will only be traveled by ash trucks and occasionally maintenance/supervisor trucks. This is estimated to be significantly less than the several hundred per day that EPA suggested would require paving. Further, paving the landfill haul road is not feasible because the location of the road changes as the landfill utilization changes (i.e., the working face of the solid waste facility and dump location for trucks continually changes which would require constant changes in roads). Thus, as stated above, BACT for the landfill haul road was determined to be either the application of chemical surfactant or documented watering to achieve a control efficiency of 98%. These BACT conclusions are consistent with similar conclusions in EPA Region 7.[167] Accordingly, Georgia Center's comments are without merit.

3. EPD Failed to Perform a BACT Analysis for PM 2.5.

EPD performed no BACT analysis for PM 2.5 in the PD.[168] While PM 2.5 may not have been applicable when application was submitted, it is applicable now. A BACT determination for this pollutant was required. Furthermore, EPD is required to insure no adverse impact on the National Ambient Air Quality Standard (NAAQS) for PM 2.5. Notwithstanding EPA policy statements, EPD is required by law to conduct a full PSD analysis for PM 2.5 and to insure that

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[165] See App C at
27.
[166] USEPA, 1995. AP 42 – Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, page 13.2.2-10 (emphasis added).
[167] State of Missouri, Department of Natural Resources, Missouri Air Conservation Commission – Permit to Construct. City Utilities of Springfield, Permit Number 122004-007, December 15, 2004. State of Missouri, Department of Natural Resources, Missouri Air Conservation Commission – Permit to Construct. Great Plains Energy, Permit Number 012006-019, January 31, 2006.
[168] *See* App D.

> NAAQS and human health and welfare are protected by the issuance of this permit.

Response: Please refer to Comment 10 of this Final Determination for more information on this topic.

> Pre and post-construction monitoring for PM 2.5 should be required. Failure to consider impacts on PM 2.5 means that the BACT analysis is deficient and not responsive to the requirements of Federal and State law.

Response: LEA has committed to monitoring pre and post operation which may include PM2.5 depending on the needs of the EPD at the time monitoring is to be initiated.

> In addition, the control, economic and environmental impacts analyses are flawed and incomplete. For example, the Wet ESP provides superior performance in capturing fine aerosol particulate matter, HAPs and SAM. The BACT analysis fails to consider these impacts. The cost effectiveness of the Wet ESP is reported as $98 per ton as a PM and lead control device, but as $255,754 as a control device for SAM. This is inconsistent with other economic analyses such as the analysis of HF which is a co-control benefit of SO_2 and a not estimated as a separate cost.

Response: As addressed above, EPA has issued guidance that due to the difficulties of estimating $PM_{2.5}$ impacts, $PM_{2.5}$ impacts do not need to be considered as part of PSD at this time; compliance with PM_{10} requirements fulfills the requirements for $PM_{2.5}$.

For both the PM/PM_{10} analysis and the H_2SO_4 (SAM) analysis, LEA used the same total annualized cost for a wet ESP (WESP) over the baseline — approximately $7,000,000 per year. The reason the cost effectiveness appears to differ is because the baseline emissions of H_2SO_4 are less than PM/PM_{10}. Thus, when the calculations are performed, PM/PM_{10} has lower reported cost per ton than H_2SO_4, but LEA did not provide different cost information.

LEA did not include an economic analysis of control options for HF because the highest level of control – a dry scrubber – was selected. This approach is supported by guidance from the Draft NSR Manual, which states that "an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options."[169] The conclusion that a dry scrubber provided the highest level of removal for HF is supported by EPA research. EPD found no documentation that suggests that a WESP could provide significant removal of HF, so the dry scrubber was the top option and was selected. Thus, there was no need to provide separate cost information.

[169] U.S. EPA, *New Source Review Workshop Manual (Draft)*, 1990, p. B.8.

4. PM10

EPD erred because IGCC should have been considered as part of the BACT analysis, but was not. BACT for the Taylorsville Energy Center was 0.0063 lbs/MMBtu for PM as compared to the 0.015 lbs/MMBtu that EPD has selected as BACT. In addition, IGCC is more thermally efficient than subcritical or supercritical pulverized coal boilers. IGCC, ultra supercritical and supercritical boilers are technologies that impact emissions of PM and must be considered in a proper BACT determination.

Response: Please refer to Comment 45 of this Final Determination for more information on this topic

53. H_2SO_4

The rejection of the wet scrubber is based on erroneous information. The best performing unit similar to the Longleaf proposal is WA Parish Unit #8. This unit has an emissions limit for SAM of 0.0015 lbs/MMBtu. Parish #8 is a 650 Mw pulverized coal unit burning low sulfur Western coal. Parish #8 is controlled by a wet scrubber and a baghouse. EPD's analysis of control of SAM proposes 50% control for a wet scrubber, but apparently fails to evaluate a wet scrubber with baghouse. The economic analyses are also flawed because they also apparently omit this combination. The economics of the added wet ESP appear to be the chief factor in EPD's rejection of a more stringent BACT emissions limitation for SAM.[170] The determination is further flawed because the basis of determining economic impact under BACT is comparison to the economic burden others have had to bear to control that pollutant. No information is provided on appropriate cost effectiveness for SAM. In addition, a wet ESP is effective at controlling mercury emissions and emissions of fine and condensable particulate matter. No details are provided in the economic analyses to determine if these economic and environmental benefits are considered.

Response: According to the RBLC database, the primary fuel for WA Parish Unit #8 is natural gas, although it has the capability to also burn coal or distillate oil. As a primarily natural gas-fired unit, it is not comparable to the Facility, which will primarily be fired by low sulfur coal and will not have any natural gas-firing capability.

LEA utilized a control efficiency of 50% for a wet scrubber based on vendor information and published data.[171] This removal was not specific for a wet scrubber with an ESP or for a wet scrubber with a baghouse. Rather, it was a generalized control efficiency for a wet scrubber. As was found in Texas however, even if a higher removal efficiency is assumed for a wet scrubber with baghouse, a dry scrubber will still be more effective at H_2SO_4 removal. The BACT analysis was based on published or vendor data, and LEA has not

[170] PD, at 133.
[171] From *Furnace Injection of Alkaline Sorbents for Sulfuric Acid Removal, Final Report,* DOE-NETL.

found published data for a wet scrubber combined with either an ESP or a baghouse that would refute the control efficiencies used in the BACT determination.

EPD does not believe that because of the configuration differences between wet scrubbed and dry scrubbed systems, a wet scrubber with a baghouse will have an appreciable improvement in H_2SO_4 removal. As discussed in Section E.3 of the permit application, the calcium sulfite/sulfate mixture captured in the baghouse after the dry scrubber provides the mechanism for H_2SO_4 removal. In a wet scrubber baghouse system, the baghouse is located upstream of the wet scrubber, so any H_2SO_4 generated by the wet scrubber would not be captured. Generation of H_2SO_4 by wet scrubbers has been documented in the literature as a result of bulk gas cooling upon contact with the water in the wet scrubber vessel.[172]

While LEA did not provide the cost analysis for other projects, LEA did provide a list of projects which rejected a WESP as a basis for control of H_2SO_4. Table D.30 of the Application showed that only two projects had selected a WESP for control, and they both have the same emission limit proposed for the Facility. Thus, while comparable economic cost information from other projects' BACT analyses were not provided, the BACT determinations from those other projects were provided. These BACT determinations did not find the WESP to be BACT. Therefore, the determination of BACT by EPD was found to "be consistent with recent BACT determinations."[173]

EPD is not aware of any literature or research supporting Georgia Center's claim that a WESP is effective at controlling mercury. Additional information regarding this claim would need to be provided by the Georgia Center before this claim can be analyzed. This is especially true given the high elemental mercury content associated with burning PRB coal, since elemental mercury is not a charged chemical species and thus is not likely to be attracted by the charged plates associated with a WESP. As part of the BACT analysis, LEA attributed a significant amount of control (95%) to the WESP for control of fine and condensable particulate matter. Georgia Center has not provided any evidence to suggest the level of control should have been higher. No changes have been made to the permit based on this comment.

[172] Buckley, W. and B. Altshuler, "Sulfuric Acid Mist Generation in Utility Boiler Flue Gas," www.energypulse.net, 2003.
[173] PD at 119.

54. Lead

The BACT emission limit established for lead, 1.8X 10^5 lb/MMBtu based on thirty-day average, is unreasonably high. The PSD permits for Thoroughbred Generating Station, Keystone, and Spruce Unit 2 all have stricter limits. The deficiencies noted for the PM analysis also apply to control of lead. As with other pollutants, IGCC performs better for controlling lead. BACT for the Taylorsville Energy Center was 1.25 x 10-5 lbs/MMBtu for lead. As such, lower limits of Lead are clearly achievable.

Response: The BACT analysis determined its lead emissions based on coal quality (i.e. lead concentrations in the coal) data from the USGS CoalQual database as well as the removal efficiency of the baghouse. Based on LEA's review of the Spruce Unit 2 (CPS – San Antonio) permit application, CPS – San Antonio utilized historical fuel records for the last couple of years of fuel delivered to Spruce Unit 1 as the basis for its lead emission rate. The Facility is not in operation and therefore cannot use the same approach for determining lead concentrations as CPS – San Antonio is able to use. LEA is utilizing the same control technology as CPS San Antonio, a baghouse, for removal, so differences in emission rates are solely based on inlet lead assumptions and Georgia Center has not provided any reason why the USGS database is not a valid source for coal lead concentration. The basis for the uncontrolled emission rate at Thoroughbred was not provided in its application. No changes have been made to the permit based on this comment.

55. Hydrogen Fluoride

EPD's analysis of BACT for hydrogen fluoride (HF) is flawed. The rejection of the wet scrubber is based on erroneous information. EPD reports that water consumption is increased.[174] This is an economic consideration. The determinant in economic consideration is comparison with the burden that other similar facilities have had to bear in controlling their emissions. A cost effectiveness of $761/ton of SO_2 controlled is not an excessive burden nor a basis for rejecting wet scrubbing as BACT. Assertions about control of HAPs are seriously misleading. This assertion is based on the BACT analysis for hydrogen fluoride (HF). The case that LS Power has made for the superiority of dry scrubbing over wet scrubbing is based entirely on a few limited data points from EPA's "Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units Final Report to Congress," February 1998. On page 51 of the Preliminary Determination, EPD asserts that 230 tons less HAP as HF will be emitted by the dry scrubber system because of interactions between the fly ash and the HF in the baghouse. This is based on the assertion in the HF BACT analysis that the dry scrubber will control 95% of HF and the wet scrubber 44%.[175] However, this is inaccurate and misleading. This EPA reference is based

[174] PD, at 97.
[175] PD, at 102.

on comparing a wet scrubber with an ESP to a dry scrubber with a baghouse,[176] in spite of the assertion by LS Power that it is the baghouse that achieves the effect of control. As Longleaf is proposed with a baghouse and a wet scrubber, the control of HF should be equivalent or better with the wet scrubber at Longleaf than for the dry scrubber. For control of sulfuric acid mist (SAM), the wet scrubber with wet ESP is superior to the dry scrubber. As this option is not properly evaluated, it is incorrect to cite this as a basis for selection of the dry scrubber over the wet scrubber.

Response: Please refer to Comments 48 and 53 of this Final Determination for more information on this topic. No changes have been made to the permit based on this comment.

EPD failed to compare and consider several technically feasible options including, IGCC and comparison of subcritical, supercritical and ultra-supercritical pulverized coal technologies. A supercritical boiler is clearly an inherently less polluting technology in comparison to a subcritical boiler in that due to the higher thermal efficiency of a supercritical boiler, it produces more electrical power for the amount of coal burned. This means that on an hourly basis and annual basis, the supercritical boiler is expected to produce less pollution than a sub-critical boiler generating the same amount of electricity. In order to accurately compare the emissions from IGCC, subcritical, supercritical and ultra-supercritical technologies for generating electricity from the combustion of coal, BACT should also be listed in terms of pounds per gross megawatt hour (lbs/MW-hr) as well as lbs/MMBtu. EPA's "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, July 2006", pages 3-38, give a HF emissions rate of 9.2 x 10-5 for IGCC which is more than ten times lower than the BACT proposal for the Longleaf permit.

Response: Please refer to Comments 1 and 45 of this Final Determination for more information on this topic.

[176] http://www.icci.org/99final/devito2.htm

56. Class I Areas/Air Quality and Visibility Modeling used Coarse and Outdated Data.

The Calpuff model is the principal model used for air quality and visibility impact analyses of the proposed Longleaf Energy Station. Normally, the Calpuff modeling uses meteorological data generated by appropriate mesoscale models for three consecutive years and at spatial resolution fine enough to accurately stimulant pollutant transport in the study region. As shown in the November 2004 Class I Modeling Report page 1-2, meteorological data from three different years (1992, 1996 and 2003) were used in the modeling. These data were generated by mesoscale models MM5 and RUC at different spatial resolutions: 80 km for the 1992 MM5 data, 36 km for the 1996 MM5 data, and 20 km for the 2003 RUC data. These meteorological data were used by the Calmet preprocessor to generate the windfields and other meteorological inputs required by the Calpuff modeling. These data, especially the 1992 data, are too coarse for an accurate simulation of pollutant transport as well as other micrometeorological processes such as fog and clouds. The two closest PSD Class I areas (Bradwell Bay Wilderness Area and St. Marks Wilderness Area) are located less than 160 km from the Longleaf site. With a 80-km resolution in the 1992 MM5 data, these PSD Class I areas are only two grid cells away from the plant and pollutant transport are, thus, poorly characterized by meteorological data in these two grid cells. In addition to the problem of coarse resolution, the 1992 data and even the 1996 data are outdated by more recent MM5 datasets, such as the 2001 and 2002 MM5 data. These more recent data have been generated at 36 km and 12 km grid resolutions for regional ozone and haze modeling by the U.S. EPA and various regional planning organizations (RPO). Georgia belongs to a RPO named VISTAS (Visibility Improvement State and Tribal Association of the Southeast). The MM5 2002 dataset has been generated for VISTAS and used in photochemical modeling by Georgia EPD. It is described in Abraczinskas et al. (2004). This publication is available from the VISTAS website http://www.vistas-sesarm.org. Thus, the Calpuff modeling used outdated and inappropriate meteorological data (the 1992 and 1996 data), and these datasets should be replaced with the more recent 2001 and 2002 MM5 data.

Response: Georgia Center contends that LEA should have used more recent data to conduct its Class I Area modeling. Georgia Center has failed to recognize the fact that this more recent data did not exist at the time LEA conducted its modeling. LEA's Class I modeling was performed in 2004. At that time, LEA utilized the most sophisticated modeling available. LEA hired Mr. Joe Scire from Earth Tech to complete its Class I modeling. Mr. Scire is a recognized expert in the use of Calpuff and Class I modeling, in part because of his role in developing the Calpuff model. EPD's modeling team reviewed and approved LEA's modeling. Additionally, the FLM for Bradwell Bay concluded in an e-mail to EPD on February 22, 2006 that LEA's modeling appears to have been conducted correctly.

Modeling regulations and guidance do not require applicants to update air permit modeling as more recent meteorological data becomes available. While the datasets used by LEA do have a coarser grid than those proposed by the Georgia Center, the intent of using mesoscale modeling is to reflect broader wind patterns that are not obvious when utilizing individual surface and upper air stations. Because terrain of the southeast is considered "non-complex", a more refined grid is not necessary, as the coarser grid can still provide the proper regional wind patterns.

57. Class I Areas/Air Quality and Visibility Impacts have been Understated.

> In the Calpuff modeling of air quality and visibility impacts at PSD Class I areas, only emissions from the main boilers were modeled, and emissions from the auxiliary boilers and other low-level sources (materials handling, emergency generators and firewater pumps) were not included in the modeling. Thus, air quality and visibility impacts are understated due to the omission of emissions of auxiliary boilers and other low-level sources.

Response: In the October 6, 2004 Class I modeling protocol prepared by Earth Tech, LEA indicated that only the PC boilers would be modeled. No comments from either EPD or the FLMs were received on the protocol suggesting the screening approach was incorrectly applied.

As a practical matter, limiting modeling to only main sources is typical for long range transport analyses. As evidenced by the PM modeling for LEA's Class II analysis, impacts from sources other than the main boilers are close in (radius of influence (ROI) of 4.2 km for 24-hour) versus SO_2 (ROI of 20.5 km for 24-hour). With the Class I areas being 130 km and 150 km from LEA, the impacts from the low level sources will be insignificant. Additionally, the auxiliary boiler is a limited use source that is planned for operation only during periods of startup, shutdown, and when the Facility is not operating. The Draft Permit reflects this limited use in Condition 2.16. The limited use combined with the insignificant emissions from the auxiliary boiler underscore the lack of impact this small source would have.

It has been the FLM's practice to allow screening of sources that would likely be insignificant as a means of reducing the substantial effort required for Class I analyses.

Using the FLM screening procedure shows that neither the low-level sources nor the auxiliary boiler were required to modeled at a distance of 130 and 150 km because the impacts would be so small.

58. Inappropriate Modifications to the FLAG Procedure are Used to Lower the Significant Impacts On Regional Haze.

With the recommended FLAG screening Level I procedure (implemented as Method 2 in Calpuff), Longleaf emissions will cause significant impacts on regional haze at St. Marks Wilderness Area that is the closest Class I area. Table 5-4a of the. November 2004 Class I Area Modeling Report shows a maximum change in extinction of 10.8% that was predicted to occur in 1992. With the base case (Method 2), changes in extinction coefficient over 5% were also calculated for several days in 1992, 1996 (Table 5-4b) and 2003 (Table 5-4c). These tables also show results of various modifications to the recommended Method 2, including effects of natural weather events such as rain, snow and fog (Method 7) a higher Rayleigh scattering term (11.65 Mm-1 instead of 10 Mm-1), sea salt background and ammonia limiting method. Only the combined effects of all these modifications are able to reduce the maximum extinction change from 10.8% to 6.3% (Table 5-4a).

The above modifications to the FLAG Level 1 procedure are not recommended or approved by regulatory agencies. The National Park Service (NPS) has stated that Method 7 is not acceptable.[177] Thus, without the ad hoc modifications to the FLAG screening procedure, significant visibility impacts due to Longleaf emissions are predicted to occur at the St. Marks PSD Class I area.

Response: The methodology utilized to evaluate the results of the modeling, the various modifications to modeling results for natural weather events, a higher Rayleigh scattering term, sea salt and ammonia limiting was performed based on previously accepted FLM guidance and discussions between Mr. Scire and the FLMs. The same approach was previously used for the Savannah Electric Plant MacIntosh combined cycle unit in 2003 and accepted by the FLMs. The Method 7 analysis appropriately considers weather events such as fog and rain to modify the natural background conditions that project impacts are being compared against. The Department of Interior Assistant Secretary for Fish Parks and Wildlife issued a letter January 10, 2003 stating that "[i]t is our interpretation that "natural conditions" include significant meteorological events such as fog, precipitation, or naturally occurring haze."[178]

With the "beyond FLAG" analyses, the highest impact the LEA facility would have on visibility is one day over 5% at 6.3% as shown on page 5-8 through 5-10 of Appendix M

[177] NPS, 2006.
[178] United States Department of the Interior, Office of the Secretary, Letter from Craig Manson to Ms. Jan Sensibaugh, January 10, 2003

of the Application. The FLAG guidance states that if impacts are between 5% and 10% the FLM will consider the frequency, magnitude and duration of those events in its determination of impacts to Class I resources; impacts less than 5% are not likely to be considered potentially problematic. Thus, a single day over 5% would mean impacts have a low frequency, duration, and, at 6.3% a small magnitude.

Based on the FLM's current guidance and need to address natural background, the FLM's have said that their current approach to modeling analyses would be to utilize the 98th percentile rather than evaluate weather considerations. If the 98th percentile were utilized for the Facility's modeling results, the highest impact would be the 22nd highest value. LEA only had 21 days over 5% under the FLAG analysis; therefore, the 22nd highest value is below 5% and thus below the FLM threshold for additional consideration.

59. Advanced FLAG Levels II and III Procedures Should be used to Assess Regional Haze Impacts.

Since the FLAG-recommended Level I screening procedure predicted significant impacts by Longleaf on regional haze at the St. Marks PSD Class I area, and the ad hoc modifications have been shown to be inappropriate (see Comment #3), advanced visibility modeling procedures should be used, such as the Level II and Level III procedures recently recommended by NPS.[179] The NPS advanced procedures are based on more refined dispersion and visibility modeling to simulate the instantaneous degradation of visual air quality indexes along idealized sight paths under various ambient lighting conditions.

Response: As has generally been highlighted in the previous three responses, LEA has properly conducted the FLAG analysis, and that analysis concluded no significant impact on the St. Marks Class I area will occur. That conclusion was not disputed by either EPD or the FLMs. Therefore, no additional modeling is required.

In addition, it should be noted that Mr. Schichtel, whom Georgia Center quoted, stated at the beginning of the referenced presentation that any use of advanced procedures would require close coordination with the FLMs since those procedures have neither been formalized or documented. The FLMs did not find that LEA had significant impacts on the St. Marks National Wildlife Refuge; therefore there would have been no reason to utilize those advanced procedures required by the Desert Rock facility and presented by Mr. Schichtel.

[179] Proposed FLAG Level II and III Visibility Assessment, Bret A. Schichtel et al., 2005.

60. No Analysis of Cumulative Visibility Impacts at PSD Class I Areas Has Been Performed.

Only a regional haze impact assessment has been performed for project-only emissions. In addition to Longleaf, there are several facilities in the cumulative SO_2 inventory that have large emissions of SO_2. Tables 2 and 3 of the August 2005 Class I Area Modeling Addendum show the following plants with SO_2 emissions larger than the Longleaf Energy Station: AB Hopkins, Miller Brewing and Stone Container. These facilities and others in the cumulative inventory not only emit SO_2 but also large amounts of NO_x and PM_{10} that can cause visibility impairment. Thus, cumulative visibility impacts at the St Marks PSD Class I area need to be performed.

Response: LEA is not aware of any specific regulatory requirement or guidance that would require cumulative visibility modeling for the Facility. A request for cumulative visibility modeling could have been made by the FLMs under the FLAG guidance, but this step was not requested by the FLM.

In general, FLAG recommends that an applicant: "Consult with the appropriate regulatory agency and with the FLM for the affected Class I area(s) or other affected area for confirmation of preferred procedures and for the need for a cumulative analysis."[180] LEA and EPD complied with this provision, fulfilling all requirements.

61. Class II Areas/Air quality Impacts from Project-related Emissions may be Underestimated by about 200%.

Air quality modeling for PSD Class II areas was performed with the ISCST3 model. This modeling used a stack height of 460 ft (140 m) that is below the good engineering practice (GEP) height of 696 ft (212 m). This GEP stack height has been determined by LEA.[181] Since the modeled stack height is lower than the GEP stack height, high pollutant concentrations can occur as a result of cavity or wake effects from nearby buildings.

U.S. EPA Guidelines on Air Quality Models - Revised states that "if stacks for new or existing major sources are found to be less than good engineering practice, then ambient air quality impacts associated with cavity or wake effects due to nearby building structures should be determined."[182] However, the ISCST3 model does not simulate the cavity effects on pollutant dispersion. The US EPA Modeling Guidelines have recommended the ISC-PRIME model or the AERMOD model for predicting impacts within the cavity region. Both of these models use the improved PRIME algorithms for building cavity effects. It is noted that the Calpuff model used in PSD Class I modeling also implements these PRIME algorithms for

[180] Federal Land Managers Guidance, 2000, Page 6.
[181] Longleaf Permit Application, page 5-4.
[182] Appendix W to 40 CFR part 51.

building downwash. The ISCST3 model is being replaced by the AERMOD model as of November 2006. In a comparison of the ISCST3, ISC-PRIME and AERMOD, it has been shown the ISCST3 model underestimates the maximum concentrations of ISCPRIME by up to a factor of 2.24, and those of AERMOD by a factor of 1.87 for downwash cases. This model comparison was performed by US EPA.[183] AMI has also performed a comparative study of ISCST3 and ISC-PRIME, and results of this study also shows that the ISC-PRIME concentrations are higher than those of ISCST3 by up to a factor of 3.31 (Tran, 2001a). Thus, pollutant concentrations predicted for Longleaf by the ISCST3 model and used in comparing against NAAQS and PSD increments maybe underestimated by a factor of 2!

Response: LEA filed a modeling protocol with EPD on February 26, 2004 that identified the use of ISCST3 and included analysis of the downwash effects suggested by Georgia Center. Prior to filing the Application, LEA obtained written approval of the modeling protocol from Mr. James Stogner, a senior member of EPD's modeling team. The ISCST3 model was an approved model at the time the Application was filed on November 19, 2004. The AERMOD model was not approved for use by EPA and would have required special permission. While the approved model has changed since the time the Application was submitted, EPA does not require that sources remodel impacts. This is evidenced by EPA's allowance of modeling with ISC or AERMOD for applications submitted by December 9, 2006, despite having found AERMOD to be the new approved regulatory model on November 9, 2005.

62. No Assessment Against $PM_{2.5}$ National Ambient Standards was Performed.

The Longleaf PSD Permit Application does not include a modeling analysis of the project emissions against national ambient air quality standards (NAAQS) for particulate matter with less than 2.5 microns in diameter ($PM_{2.5}$). In July 1997, EPA issued an annual standard set at 15 ug/m^3, based on the 3-year average of annual mean $PM_{2.5}$ concentrations and a 24-hour standard of 65 ug/m^3, based on the 3-year average of the 98th percentile of 24-hour concentrations. EPA has recently (in September 2006) tightened the 24-hour standard from 65 ug/m^3 to 35 ug/m^3 and retains the annual standard at 15 ug/m^3.

$PM_{2.5}$ emissions and concentrations from Longleaf can be estimated from the size distribution of particulate matter reported in Table 2-2 of the November 2004 Class I Modeling Report. This data has been taken from EPA's AP-42, Table 1.1-6 (Baghouse). These tables show that the PM_{10} and $PM_{2.5}$ fractions are 0.92 and 0.53, respectively, of the filterable PM emissions. Thus, $PM_{2.5}$ is approximately 58% of PM_{10}. This percentage can be used to scale the PM_{10} emissions and modeled concentrations from the Longleaf sources alone (e.g., main boilers). Applying this 58% percentage to the maximum 24-hour PM_{10} concentration of 75.4 ug/m^3 that was calculated by the ISCST3 model for cumulative sources during facility

[183] Table 4-4 of Comparison of Regulatory Design Concentrations of AERMOD vs. ISCST3, CTDMPLUS and ISC-PRIME, EPA-454/R-03-002, June 2003.

startup,[184] it can be estimated that the corresponding maximum 24-hour $PM_{2.5}$ concentration is 43.73 ug/m^3. This maximum $PM_{2.5}$ from cumulative emissions alone will exceed the recently proposed 24-hour $PM_{2.5}$ standard of 35 ug/m^3. With the added ambient background, both this recently proposed standard and the existing standard (65 ug/m^3) will be violated.

Response: PM2.5 fractions utilized for the Class I report are based on AP-42 data. This data carries a quality rating of "E" which is very poor. Due to the poor scientific understanding of fine particulate emissions, as discussed above, EPA is not requiring comparison against $PM_{2.5}$ NAAQS at this time.

63. Health Effects of Mercury Emissions have been Ignored.

Table 3.1 of the November 2004 PSD Permit Application shows that the project will emit significant emissions of mercury (0.11 tpy). These mercury emissions were ignored in the ambient assessment of toxic emissions shown in Appendix I of the November 2004 PSD Permit Application. This omission of mercury is in violation of the recommendations of the EPD toxic assessment guideline that requires the evaluation of all emitted toxics.[185]

Response: Mercury was included in the ambient assessment conducted by LEA. It is included on line 12 of Appendix I of the Application. Section 4.0 of the Preliminary Determination details the analysis of mercury. Georgia EPD has required Longleaf to install halogenated activated carbon injection and the mercury limit is significantly lower than the Clean Air Mercury Rule (CAMR) required by EPA.

64. The Project will Emit Several Toxic Chemicals and Their Health Risks have not been Fully Quantified

A coal-fired power plant such as Longleaf will emit several toxic chemicals that are known to be carcinogens and/or to cause non-cancer acute and chronic health effects. Table 3.1 of the November 2004 PSD Permit Application shows that the project will emit significant emissions of lead (0.65 tpy), fluorides (159 tpy) and mercury (0.11 tpy). The project emissions will largely exceed the corresponding PSD significant emission rates as defined in 40 CFR 52.21 (PSD Regulations). For example, the PSD significant emission level for fluorides is 3 tpy, and this level is largely exceeded by the project emissions of 159 tpy. As shown in Appendix I of the November 2004 PSD Permit Application, the Longleaf Energy Station will also emit several other toxic substances, including dioxins, beryllium, and chromium.

[184] Table 6, at 6, August 2005 Supplemental Class II Modeling Report.
[185] Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions, EPD, GA DNR, Revised June 1998.

Response: The only purpose for PSD significant emission rates is for determining whether PSD review is triggered for a particular pollutant. LEA has performed a full PSD review for all pollutants determined to be above the significant emission rate.[186]

For the other toxic substances, EPA evaluated the need to regulate toxic emissions from coal-fired power plants as part of the MACT evaluation process. From that investigation, EPA determined that mercury was the only toxic pollutant that warranted additional regulation. LEA will be required to comply with all applicable regulations for mercury (e.g., NSPS Da, CAMR).

> An ambient assessment of toxic emissions was performed and documented as Appendix I of the November 2004 PSD Permit Application. This LEA assessment claimed to follow the EPD toxic assessment guideline.[187] The EPD guideline only recommends the comparison of maximum 24-hour concentrations against acceptable ambient concentrations. The LEA analysis not only omitted the impacts of mercury, the LEA analysis also did not consider health risks from non-inhalation pathways. Furthermore, it also did not quantify the cancer risks for carcinogens and non-cancer acute and chronic hazard indices for non-cancer health effects.
>
> A full health risk assessment will need to be conducted to assess potential health effects of the toxic chemicals emitted by Longleaf as part of public health and environmental justice concerns. AMI has developed a model named ACEHWCF (Assessment of Chemical Exposure for Hazardous Waste Facilities) that can evaluate both inhalation and non-inhalation risks using the multipathway exposure algorithms recommended by the U.S. EPA.[188] The ACEHWCF model has been described in a technical paper (Tran, 2001b) and this document is available from AMI's website.

Response: EPD's guideline is a screening procedure used to determine if further investigation is necessary. LEA followed the Georgia Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (the "Guideline") and worked closely with Mr. James Stogner of the EPD in determining the correct comparison for each pollutant known to be emitted from the Facility. The comparison in Appendix I of the Application includes comparisons for 15-minute averaging periods in addition to the 24-hour or annual concentrations identified by Georgia Center as required by the Guideline. Columns 4 through 8 identify 15-minute averaging periods for those pollutants which have threshold criteria, and a comparison is made between LEA's expected ambient concentrations and those criteria.

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[186] *See* 40 C.F.R. § 52.21(b)(23)(i).
[187] Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions, EPD, GA DNR, Revised June 1998.
[188] Human Health Risk Assessment Protocol for Hazardous Waste Facilities, Final, EPA530-R-05-006, September 2005.

The expected ambient impact for each pollutant and averaging time is identified in Appendix I of the Application and compared against the best known ambient impact threshold available at the time including the EPA Integrated Risk Information System (IRIS), Occupational Safety and Health Administration (OSHA), and others as detailed out in Appendix I. For each pollutant and the cumulative total, LEA's expected impacts did not exceed the published threshold value. Thus, based on the Guideline, further analysis is not necessary, and Georgia Center has not provided any detailed justification as to why the Guideline screening is insufficient. Finally, Georgia Center's contention that environmental justice concerns necessitate further analysis is invalid for the reasons more fully explained in Section I.

65. Project Impacts on Ozone Air Quality Have not been Addressed.

The proposed Longleaf Energy Station will emit large amounts of NO_x (3,3783 tpy) and VOC (194 tpy). Known to be ozone precursors, these pollutants react under sunlight to form ozone. The Southeast is known to have extensive biogenic emissions. These highly reactive hydrocarbons can react with the NO_x emissions from the Longleaf Energy Station to form high levels of ozone. Ozone modeling was not performed to assess the impacts of project emissions on ozone air quality in Early County and other nearby areas. Georgia EPD has conducted ozone modeling for the VISTAS project as well as SIP planning (e.g., the Augusta Early Action Compact), and emissions from Longleaf should be included to assess their ozone impacts.

Response: As EPA stated in its December 13, 2000, letter to EPD, "[a]lthough ozone impact modeling is not normally required for single sources, information on the current ozone levels in the area should be cited to provide qualitative assurance that the increased VOC emissions from facility operation will not cause or contribute to violations of the ozone national ambient air quality standards."[189] The Application followed this standardized practice for qualitatively addressing ozone impacts because the only other methodology for evaluating ozone is through regional modeling, which is impractical for an individual permit applicant.

The CMAQ modeling done by the State of Georgia analyzed several sensitivities of NO_x emission reductions from some of the Georgia Power coal-fired power plants on the town of Macon. Evaluation of those results can be used as a tool to roughly estimate the potential impacts from the Facility. By using the Facility's maximum potential to emit emission rates for NO_x, the following impacts and distances result:

- 20 mile distance – 0.88 ppb ozone
- 30 mile distance – 0.079 ppb ozone
- 85 mile distance – 0.004 to 0.24 ppb ozone
- 140 mile distance – 0.022 ppb ozone

[189] US EPA Region 4 letter to Mr. Ron Methier, Georgia EPD, December 13, 2000, page 5.

The 1-hour standard for ozone was 120 ppb. Thus, in the Early County and surrounding immediate area, LEA would be expected to contribute less than 1% of the standard, and for the more distant non-attainment areas, the modeling results, when applied to the Facility would suggest that its contribution is negligible.

In February 2006, EPA published "Air Quality Criteria for Ozone and Related Photochemical Oxidants", EPA 600/R-05/004aF. As part of the Clean Air Act requirements, EPA is required to periodically review the NAAQS and modify them as the science necessitates. The February 2006 document is an update of the 1996 document based on the numerous ozone studies done around the country and in Europe to investigate the human health and vegetative effects from ozone. The document underwent three rounds of public comment and scientific evaluation, thus it serves as a peer-reviewed compilation of the scientific knowledge of ozone impacts.

In the 2006 document, EPA concluded that no new scientific evidence had been presented since 1996 that would warrant a new secondary NAAQS for ozone. The EPA's 2006 ozone findings include the following:

- 7-hour, 3-month mean of 49 ppb would cause 10% loss in 50% of common and economically valuable crops.
- An AOT40[190] value of 5.7 ppm-h corresponded to a 10% yield loss.
- An AOT40 value of 2.8 ppm-h corresponded to a 5% yield loss.
- Europe has set a critical AOT40 level for crops of 3 ppm-h.
- Europe has set a critical AOT40 value of 10 ppm-h for daylight hours for deciduous trees. [191]
- Evergreen trees are less sensitive than most deciduous trees and slower-growing species are less sensitive than faster growing species.[192]

The data and European critical levels above are significantly higher than the 0.004 to 0.88 ppb of ozone that can be attributed to the Facility based on scaled impacts from the CMAQ modeling done for Macon. These scaled values were presented on page 54 of Exhibit B of LEA's January 5, 2007 letter to EPD. Thus, LEA does not believe that its ozone impacts will cause material vegetative impacts.

[190] AOT40 means the seasonal sum of the difference between an hourly concentration at the threshold value of 40 ppb, minus the threshold value of 40 ppb.
[191] EPA 600/R-05/004aF Volume III, Page AX9-257.
[192] EPA 600/R-05/004aF Volume III, Page AX9-259.

66. Plume Blight Impacts from Longleaf Alone are Significant.

Visibility impacts through plume blight have been analyzed by the VISCREEN model. Both the screening Level I and the more refined Level II analyses have been performed. The Level II analysis calculated potential impacts at four locations (Chattahoochee State Park, Headland Municipal Airport, Kolomoki State Park and Early County Airport) that are located within 30 km of the project site. Results of the Level II analysis are documented in the April 2005 Level II VISCREEN Analysis. They indicate that the Longleaf emissions alone will cause significant plume blight. As shown in Table 3 of the April 2005 document, large maximum values of delta-E were calculated for Headland Municipal Airport (2.44), Kolomoki State Park (3.29) and Early County (4.63). These values are well above the screening values of delta-E of 2.0. A more refined visibility analysis with the PLUVUE II model should be performed, as recommended by the US EPA Modeling Guidelines. Thus, Longleaf visibility impacts through plume blight are considered to be significant, with its plumes visible for miles from the facility site.

Response: GA EPD evaluated the techniques used in the Class II Area Visible Plume assessment. GA EPD modeling staff subsequently made its own independent evaluation, following guidance of the Workbook for Plume Visual Impact Screening

67. PM_{10} Emissions from Haul Road were Improperly Modeled as Area Sources.

An examination of the ISCST3 modeling files reveals that PM_{10} emissions from travel on unpaved roadway (source numbered S38) and paved roadway (source numbered S39) were improperly modeled as area sources. These emissions should be modeled as volume sources as recommended by the ISCST3 user's guide.[193]

Response: LEA has reviewed the ISC user's guide[194] and finds no specific guidance for modeling roads. The guidance most closely applicable to roads found by LEA is contained on page 1-9 of the ISC user's guide, which says that line sources (e.g., roads) may be modeled as a string of volume sources or as elongated area sources. Area source modeling tends to predict worst-case ambient impacts as compared to volume source modeling since area sources include no initial dispersion and no plume rise. Conversely, volume source modeling for the roads would be expected to result in lower ambient impacts since volume sources include initial three-dimensional dispersion. Based on LEA's analysis of this Georgia Center comment, LEA concludes that i) there is no specific requirement for utilizing a different modeling methodology (i.e. area sources) and ii) the Facility roads were actually modeled under a methodology expected to predict the worst-case ambient impacts.

[193] US EPA, 1995.
[194] User's Guide for the Industrial Source Complex (ISC3) Dispersion Models, EPA Document No. EPA-454/B-95-003a, September 1995

68. Project SO_2 Emissions can Cause Significant Impacts on Sensitive Soils and Vegetation.

The Preliminary Determination[195] and Section 6.3.3 of the November 2004 PSD Permit Application indicate that project emissions will not cause significant impacts on sensitive soils and vegetation since the modeled concentrations are below the screening levels recommended by the US EPA. These screening levels are documented in the EPA's *Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals.*[196] Results of the LEA screening analysis are summarized in Table 6.8 of the November 2004 PSD Permit Application. This table indicates that project emissions will result in a maximum SO_2 1-hour and 3-hour concentrations of 143 ug/m^3 and 97.4 ug/m^3, respectively. These S02 maximum concentrations are below the 1-hour screening level of 917 ug/m^3 and 3-hour screening level of 786 ug/m^3 recommended by the EPA. However, Table 6.9 of the November 2004 PSD Permit Application has reported a maximum SO_2 3-hour concentration of 1,026 ug/m^3 obtained during facility startup. This 3-hr concentration is well above the screening level of 786 ug/m^3 recommended by the US EPA. Furthermore, maximum 1-hour concentration is expected to be much higher than the maximum 3-hour concentration of 1,026 ug/m^3. This 1-hour maximum will also exceed the 1-hour screening level of 917 ug/m^3. Thus, maximum project $S0_2$ 1-hour and 3-hour concentrations will exceed the corresponding screening levels recommended by the US EPA, and can cause significant impacts on local sensitive soils and vegetation. Furthermore, there has been no effort to identify the most sensitive soils and vegetation, making the alternative impacts analysis flawed.

Response: The concentrations from Table 6.9 of the Application highlighted by Georgia Center are taken from the analysis of Facility startup. The screening levels cited by Georgia Center were taken from a document that was written prior to the time that permitting authorities required estimating and modeling of startup emissions. Because of this, the document does not address if impacts associated with BACT emission limits or other impacts are to be used. The typical practice of other permitting authorities is to use the impacts associated with BACT emission limits to evaluate impacts on vegetation and soils. Thus, based on historical permitting practices, LEA used its normal operating emission rate for evaluation of vegetation impacts.

In addition, the numbers used in the PD for the screening analysis correspond to the limits in the Draft Permit. Since the Draft Permit does not authorize the higher emission rates associated with the startup impacts shown in Table 6.9, the modeling results corresponding to the BACT limits are the appropriate values for comparison.

[195] PD, at 192.
[196] EPA 450/2-81-078, December 1980.

As part of the determination for the NAAQS levels, in November 1982, EPA Staff published the "Review of the National Ambient Air Quality Standards for Sulfur Oxides: Assessment of Scientific and Technical Information OAQPS Staff Paper", EPA-450/5-82-007. This paper includes the results from McLaughlin and Lee's studies of SO_2 impacts in the vicinity of a coal-fired power plant in the southeastern U.S. from 1970 to 1973. This is believed to be the same data that was presented by a commenter at public hearing for the Facility. The conclusions of that report found that a 3-hour secondary standard set at exposures of 1,050 to 1,300 ug/m^3 would be sufficiently protective of growth and productivity.[197] The Facility's maximum 3-hour modeled impact due to startup was 1,026 ug/m^3, a concentration lower than the bottom end of the range suggested by EPA to protect vegetative growth and productivity. The startup duration which could potentially produce impacts of that level is only expected to last three hours. The normal operation maximum impact was modeled to be 97.4 ug/m^3.

69. THE ADDITIONAL IMPACTS ANALYSIS IS FUNDAMENTALLY FLAWED.

For the reasons stated above, the vegetation analysis was flawed. There was no effort to look at the impacts of metals or ozone. Furthermore, the estimations of total ambient concentration, comprising the sum of background concentrations plus the increase due to the project were otherwise inadequate. No effort has been made to determine the injury threshold for local species as reported in authoritative works, including J, Nriagu, *Sulfur in the Environment, 1978.* Also, the analysis failed to consider the impact of project emissions on certain sensitive crop species, which are not protected by NAAQS (e.g., broccoli, peanut, alfalfa, cotton).[198] Indeed, there appears to be a discrepancy between the highest concentrations modeled in the PD versus the application. Note that the application refers to $S0_2$ impacts at 1094 ug/m3 over a three hour average.[199]

Response: Georgia Center has suggested that the vegetation analysis was flawed as a result of not evaluating sufficient pollutants and using unacceptable screening thresholds for the comparisons that were made. As documented on page 6-6 of the Application, LEA used the EPA guidance document "A Screening Procedure for the Impacts of Air Pollution Source on Plants, Soils, and Animals" to conduct its analysis. Recently the use of this document has been confirmed by EPA Region 4 as the proper source for screening values for the Thoroughbred project in Kentucky.[200] Thus, EPA continues to support this document for vegetation screening. Georgia Center's reference to a 1978 document is not presented with enough detail to determine what values it represents as appropriate. Additionally, LEA utilized the screening values comparable to the most sensitive plants, rather than inventory the surrounding vegetation to determine which level of screening

[197] EPA-450/5-82-007, (http://www.epa.gov/ttn/naaqs/standards/so2/data/sosp1982.pdf) Page 112.
[198] *See, e.g.,* Hawaii Electric in the 9th Circuit.
[199] PD, at 6-3.
[200] Secretary's Findings, Conclusions of Law, and Final Order for the Thoroughbred Generating Station, Commonwealth of Kentucky Environmental and Public Protection Cabinet File No. DAQ-26003-037 and DAQ-26048-037, 23.

values to utilize.

In addition, Georgia Center has asserted that the screening was somehow inadequate because the screening level was compared to the background plus the increase due to the project. However, Georgia Center did not provide EPD with the approach they deemed to be acceptable. LEA used the comparison methodology recommended in the screening procedure document. LEA compared the total modeled impacts (its impacts plus those of other sources required for the NAAQS analysis) plus the background to the screening levels, thus suing the comparison methodology recommended in the screening procedure document.

Metal and ozone comparisons did not need to be addressed as part of the additional impacts analysis for the Application. Georgia utilizes a toxic screening procedure to address metals and other components. As shown by the table below, the criteria for the toxic screening procedure are significantly more stringent than the most stringent screening concentrations from the EPA vegetation screening procedure for the various metals covered by both. Therefore, because of the toxic impact analysis required by Georgia, vegetation screening for metal compounds is not necessary. The EPA vegetation screening procedure also recognizes that because ozone impacts cannot be accurately modeled or predicted from a single source, no comparison to a screening level can be performed.[201]

Comparison of Metal Screening Levels to the Acceptable Ambient Concentrations from the Georgia Toxic Evaluation Procedure

	EPA Vegetation Screening Procedure (ug/m3)	Appendix I AAC Comparison Value (ug/m3)
As	836	0.2
Cd	12,538	30
Co	2,629	0.24
Cr	2,320	1.2
F	84,768	240
Pb	739,538	0.12
Mn	6,128	500
Ni	157,115	0.004
Se	17,614	0.5

While the Georgia Center has not provided detailed evidence that the methodology utilized by LEA was insufficient or incorrect, LEA has also consulted one of the potential literature sources recommended in the Draft NSR Manual that could be used for analysis of vegetation impacts. This source, the U.S. Fish and Wildlife Service's (USFWS)

[201] A Screening Procedure for the Impacts of Air Pollution Source on Plants, Soils, and Animals, EPA 150/2-81-078, December 12, 1980, 8.

"Impacts of Coal-Fired Power Plants on Fish, Wildlife, and their Habitats," presents concentration values that can be used to determine the impact of sensitive species to pollutant concentrations. The maximum 3-hr modeled concentration of SO_2 from the Facility is 97.4 ug/m3 during normal operation and 210 ug/m^3 during startup conditions. Both of these are less than the value of 388 ug/m^3 estimated from the USFWS document's sensitive plant dose-injury curve as "no injury." The USFWS document sensitive species list includes broccoli, alfalfa, cotton, and certain pine species. Accordingly, this document supports the conclusions that the impacts from LEA will not result in impairment to sensitive vegetation species.

> The growth analysis does not square with representations made to the community regarding the economic boon to the community that will be represented by this plant. The growth analysis is also unsubstantiated.[202]

Response: Georgia Center made a passing reference in their final comment alleging that LEA's discussion on growth was somehow unsubstantiated because of the economic impact projected in a study by Dr. Mac Holmes of Troy University. While the economic impact study prepared by Dr. Holmes does in fact project substantial economic benefits to the region and state resulting from the Facility, none of those impacts translate into the type of substantial growth in industrial, commercial or residential emission sources that would warrant a growth analysis for the Facility. On pages 6-4 to 6-5 of the Application, LEA provided the justification for not performing a growth analysis (although Georgia Center seems to have misunderstood that discussion to be a growth analysis). EPD accepted LEA's justification and described in the PD that the distribution of the generation and the 125 permanent jobs would not result in significant growth creating air quality impacts. Georgia Center has not provided any evidence or detail as to why the EPD's determination on page 93 of the PD is incorrect or insufficient.

[202] *Compare* Projected Economic Impact study from Mac Holmes of Troy State.

Comments from Southern Environmental Law Center – Letter dated July 31, 2006

70. Consideration of IGCC as BACT

As an initial matter, we believe that in considering an application for a new fossil-fuel-fired electric generating plant, EPD must first determine whether the asserted demand exists and whether it can be met through available conservation, efficiency, and renewable energy resources. After this analysis has been performed, if it is determined that additional coal-fired capacity is required, construction of conventional PC plants is improper, instead, any new coal-fired plants should use Integrated Gasification Combined Cycle ("IGCC") technology. PC technology is outmoded and inferior, and construction of new PC plants locks in a new commitment to that technology for the life of the plant—a half century or more. Given the global warming and other environmental challenges facing us, this choice is unacceptable.

More to the point of this letter, the Clean Air Act ("CAA") and Georgia law also prohibit the use of PC technology. These laws dictate that EPD must require LS to use IGCC technology to meet its obligation to employ the Best Available Control Technology ("BACT") for this project (the "Longleaf Project"). This letter addresses only the issue of IGCC technology as BACT. We reserve the right to address other BACT-related issues, as well as any other issues arising under the CAA, if a draft permit is issued for the Longleaf Project.

Response: Please refer to Comment 45 of this Final Determination for more information on this topic

Comments from Southern Environmental Law Center – Letter dated November 16, 2006

As we previously noted in comments submitted July 31, 2006, we believe that in considering an application for a new fossil-fuel-fired electric generating plant, EPD must first determine whether the asserted demand exists and whether it can be met through available conservation, efficiency, and renewable energy resources. We do not believe this analysis has been adequately performed.

After this analysis has been performed, additional coal units should be considered only if and to the extent that demand cannot be met using these cleaner alternatives. Construction of new pulverized-coal ("PC") units such as those proposed for the Longleaf project locks in a new commitment to an outmoded, inferior technology for the life of the plant - a half-century or more. Given the challenges of global warming and other air quality issues facing our State, this choice is unacceptable. Although we do not believe that new coal plants are necessary to meet our State's energy needs, if new coal units are built in Georgia, these units should use the most advanced and efficient technology available, Integrated Gasification Combined Cycle ("IGCC").

In our July 31, 2006 comments, we discussed the requirement to consider and require IGCC in conducting the Best Available Control Technology ("BACT") analysis for new coal-fired plants. We incorporate those comments by reference and bring to your attention two subsequent events relevant to consideration of IGCC.

71. Consideration of IGCC as BACT

<u>Page Letter Settlement</u>

First, in rejecting consideration of IGCC, EPD relied on an EPA Letter dated December 13, 2005 entitled "Best Available Control Technology Requirements for Proposed Coal-Fired Power Projects" from Stephen D. Page, Director – Office of Air Quality, Planning and Standards to Paul Plath, E3 Consulting, LLC ("Page Letter"). See PSD Preliminary Determination, 199 n.36. The Page Letter purported to set out EPA's position on whether it would require IGCC to be considered in a BACT analysis for a supercritical pulverized coal unit, taking the position that coal gasification is so different a technology from that used in supercritical PC plants that it should not be part of the BACT analysis for a supercritical PC plant. The Page Letter did not limit this analysis to any specific proposed plant. The Page Letter was, however, inconsistent with the Clean Air Act and invalid on its face.

Because of the Page Letter's clear infirmities, several environmental groups filed a lawsuit in the District of Columbia Court of Appeals challenging the application

of this letter. On or about October 12, 2006, the parties lodged a proposed settlement agreement with the court, in which EPA acknowledged that the letter "is not final agency action and creates no regulated entity or any person." That settlement is currently pending for public comment before finalization. Thus, under the settlement the Page Letter is rendered null. It cannot, therefore, be used by EPD and Longleaf to avoid conducting a BACT analysis that includes IGCC.

In re Prairie State Generating Co.

Second, the EPA Environmental Appeals Board's recently issued opinion in *In re Prairie State Generating Co.*, PSD Appeal No. 05-05 (EAB, Aug. 24, 2006), further supports our contention that a permitting agency may require an applicant to use IGCC technology to meet the BACT requirement without running afoul of the prohibition on "redefining the source." The issue in that case was whether the agency should have looked at low-sulfur coal as BACT for a plant that was proposed as a mine-mouth plant to burn coal under common control with the plant. In a narrow ruling the Board rejected this argument, holding that the use of coal from the co-located mine was so integral to the purpose and intent of the project that requiring the permit applicant to consider using some other source off coal instead would defeat the purpose of the original permit application. *Id*., slip op. 36-37. However, the decision went on to note:

> The permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility. *Id.* at 30.
>
> This test should not distinguish between IGCC and PC. Moreover, the Board note[d] that cost savings generally is not a sufficient purpose or objective that would justify treating a design element as basic or fundamental. Instead, cost is generally considered at step 4 of the top-down BACT review method. Likewise, the business objective of avoiding risk associated with now, innovative or transferable control technologies is not treated as a basic design element, but instead is considered under step 2 of the top-down method. *Id.* at 30, n.23.

In addition, the Board specifically approved the agency's requiring the applicant to look at IGCC "to determine whether further emissions reductions should be achievable through inherently lower-polluting processes or methods while still achieving Prairie State's purpose or basic design for the Facility." *Id.* at 35. Thus, it signaled that IGCC must be included in the BACT analysis even though "IGCC is not simply an add-on emissions control technology, but instead would have required a completely redesigned 'power block.'" *Id.*

Response: Please refer to Comments 12 and 45 of this Final Determination for more information on this topic.

72. Additional Comments

Finally, several of the emissions limitations in the draft permit do not reflect the best technology even if compared only to PC-fired generating units. On these points, we defer to the comments being submitted by the Georgia Center for Law in the Public Interest and others.

Response: Please refer to Comments 43 through 69 of this Final Determination for more information on the comments submitted by the Georgia Center for Law in the Public Interest.

Comments from Southern Alliance for Clean Energy

73. Failure to Determine Future Energy Demand in Georgia

The September 2006 draft of the Georgia State Energy Strategy states that at this item "no entity in Georgia compiles a comprehensive analysis of forecasted energy demand and supply for the state. Such a forecast and resource plan would prove invaluable in developing public policy, particularly on infrastructure and regulatory issues" (p.12). EPD should not grant a permit for any new power plants until as assessment of future energy demand in Georgia is conducted. The State needs to then determine whether or not the demand that does exist could be met through available energy efficiency, conservation, and renewable energy resources since these energy technologies are proven to offer the greatest public benefit. It is already documented through materials filed at the PSC that Georgia Power does not think it will need new power supplies until sometime in the future and this company has hardly begun to tap the full cost-effective potential for energy efficiency in its jurisdiction. The future supply and efficiency plans for Georgia's small utilities are not centrally compiled or available in accessible form to the public and need to be, but those utilities have not made any public case for a new pulverized coal plan to be built either.

The Longleaf Energy Station is one in a history of "merchant plants" that have been proposed or built on the premise that the power is needed. It seems probably that LS will be selling a large bulk of their power generation to Florida and/or Alabama utilities. Georgians should not have to sacrifice clean air and water simply because utilities will not take the steps necessary to build a clean, energy efficient system, and EPD and the State of Georgia certainly should not make Georgia residents and businesses have to make those sacrifices for electricity for other states.

Response: EPD had no jurisdiction over when and what type of facility wants to build in the state. EPD's job is to enforce the rules and regulations that are applicable to the proposed facility. The Georgia Public Service Commission regulates the telecommunication, gas & electric utilities operation in Georgia. The agency plays an important role in the Georgia economy by ensuring that consumers receive reliable utility services at reasonable rates while providing utilities with an opportunity to earn a reasonable return for investors.

74. Failure to Consider IGCC in analysis of BACT

Southern Alliance for Clean Energy does not agree with EPA's opinion, as noted in EPD's Preliminary Determination to "not require an applicant to consider IGCC in a BACT analysis for a SCPC unit. Thus, for such a facility, we would not include IGCC in the list of potentially applicable control options that is compiled in the first step of a top-down BACT analysis…because, EPD does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives" (p.198 Preliminary Determination).

Although the IGCC technology would require a change in the basic design of the proposed coal-fired facility, we view that IGCC would not change the fundamental scope of the project because the facility will still be using coal as the primary resource. The only change will be that the energy station will be using an "innovative fuel combustion technique" to extract the energy within the coal (p.3 Southern Environmental Law Center's comments posted August 1, 2006 on the PSD for Longleaf). Section 169(3) of the CAA, defines BACT as "an emission limitation based on the maximum degree of reduction . . . which the permitting authority . . . determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant" (p. 198 Preliminary Determination). Therefore, we believe that the EPD should rigorously review all advanced technologies that will significantly lower the emissions at the Longleaf Energy Station regardless of whether or not it will require an inherent change in the design of the facility.

Response: Please refer to Comment 45 of this Final Determination for more information on this topic.

75. Failure to Include Impact of Air Permit on Water Quality

Air emissions from the Longleaf Energy Station could adversely affect water quality in the region depending on the types of pollutants emitted. EPD should review what affect air pollutants such as lead, sulfuric acid mist and fluorides, all of which will be emitted in significant quantities by Longleaf, as put forth in the preliminary Determination, will have on the water quality of the Chattahoochee.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the air, water withdrawal and NPDES permits. The Georgia Rules for Air Quality Control and the Federal Rules for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) are designed to protect the environment and human health.

76. Failure to Consider Real Cost of Electricity Produced

It is highly likely that given the recent trends in state, regional, and international climate policy, that the Longleaf Energy Station will be further regulated during its lifetime, adding a significant cost to the operation of this facility. A number of regions in the United States have developed initiatives to curb global warming pollutants including the Regional Greenhouse Gas Initiative (RGGI) of the Northeast and Mid-Atlantic States to control CO_2 emissions. On August 15, 2006 the seven participating states reached agreement on the nation's first cap and trade program for CO_2. The states set out to "develop a multi-state cap-and-trade program covering greenhouse gas (GHG) emissions. The program will initially be aimed at developing a program to reduce carbon dioxide emissions from power plants. In addition to RGGI, regional activity to control global warming pollution is happening with the West Coast Governors' Global Warming Initiative between California, Oregon, and Washington and the Southwest Climate Change Initiative between Arizona and New Mexico. It is probable that the Southeast and/or the federal government will decide to take part in a cap and trade program in the future and that the cost to produce electricity from traditional pulverized coal plants in the Southeast could change drastically.

Secondly, EPD and the State of Georgia should take into account the full societal costs of developing a coal-fired power plant such as the health costs (i.e. the number of emergency room and doctors visits due to asthma attacks, cardiopulmonary disease, cancer, etc . . .) and the environmental costs, when considering which pollution control technologies provide the greatest benefit for Georgia. EPD should consider reevaluating the pollution control equipment requirements for Longleaf using a full cost benefit analysis.

Response: At this time EPD is not participating in a cap and trade programs for GHG. Please also refer to Comment 77 of this Final Determination for more information on this topic.

77. Failure to Consider Full Impact on Air and Climate:

Coal fired power plants in general, even if they comply with Federal and State air quality requirements, generate a great deal of air pollutants that have an effect on regional air quality as well as the overall climate. According to EPD, "the regulated pollutants, which will be emitted in significant quantities from the facility are fine particulate matter (PM10), nitrogen oxides (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOC), sulfuric acid mist (HSO), fluorides (as HF), and lead (Pb)" (p.5 *Preliminary Determination*). If permitted, all of these pollutants will have a significant effect on the rate of asthma, cardiopulmonary disease, birth defects, cancer and premature death in this region.

Georgia's geographic location and unique geology make the State highly vulnerable to global warming. An increase in se level rise and an increase in the intensity of tropical cyclones will dramatically affect Georgia's costal region. Just a slight change in Georgia's coastline could affect coastal industries, real estate values and pristine coastal habitats. If permitted, Longleaf Energy Station will contribute to the problem by releasing global warming pollutants.

In conclusion, Southern Alliance for Clean Energy believes that EPD should reevaluate the Preliminary Determination for an air quality permit for the Longleaf Energy Station. EPD failed to factor into consideration Georgia's energy demand, IGCC in the BACT analysis, the overall cost of developing the energy station, water quality impacts, and the impacts on air and climate before determining whether or not to grant an air quality permit for the Longleaf Energy Station. It is our belief that if EPD takes all of these factors into consideration, they will reconsider granting an air permit for the Longleaf Energy Station.

Response: The Georgia Rules for Air Quality Control and the Federal Rules for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) are designed to protect the environment and human health. An air quality analysis is required of the ambient impacts associated with the construction and operation of the proposed modification. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed new major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class II or Class I area. NAAQS exist for NO_2, CO, PM_{10}, SO_2, Ozone (O_3), and lead (Pb). PSD increments exist for SO_2, NO_2, and PM_{10}.

There are no applicable NAAQS or specific Georgia ambient air standards for the non-criteria pollutants being emitted, such as HAPs. Impacts from each of the pollutants listed in this letter were analyzed using the EPD Guidance for Ambient Impact Assessment of Toxic Air Pollutant Emissions (referred to as the Georgia Air Toxics Guideline; Version

June 21, 1998). The Georgia Air Toxics Guideline is a guide for estimating the environmental impact of sources of toxic air pollutants. A toxic air pollutant is defined as any substance, which may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard.

The Georgia Air Quality Act and the Georgia Rules in 391-3-1-.03(1)(c) state that the permit for the construction or modification of any facility shall be issued upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Therefore, Georgia EPD must issue an air quality permit for the Longleaf facility if they meet all applicable requirements in the rules and regulations that are applicable.

Comments from F.C. "Butch" Wiggins President and CEO Bank of Early

I have been a resident of Early County for 15 years. I am currently President of Back of Early and have recently been elected to the Early County Board of Commissioners. I have served as President of the Blakely-Early County Chamber of Commerce and Chairman of the Early County Development Authority and been involved in every aspect of economic development of the area.

In 2001, discussions began regarding the location of a coal fired, electrical generating plant in Early County. Various positions were established, both for and against, the plant.

As LS Power formulated their plans, I considered the position of the various groups and attended several meeting help by those supporting the power plant as well as those against it. The Early County Development Authority sought the support from the business community to encourage LS Power to locate this plant in Early County. Our banks, civic clubs and other groups wrote letters of support in the early stages of the project. I seemed to all of us that the economic benefits to our area were substantial and very much needed in this economically distressed area. At that time, little thought was given to the environmental impact of the plant.

Limited opposition to the plant continued. The opponents were almost exclusively those individuals (and their family and friends) who owned land either adjacent to or very near the proposed site of the plant. In some cases however, adjacent landowners remained neutral and others offered firm support for LS Power. Various environmental groups such as the Sierra Club became involved in the project and provided the background and support from an environmental perspective to those local individuals opposing the plant.

I remained in support of the project but with reservations. My reservations included a need for better understanding of the environmental consequences as well as a quantification of the positive economic impact to our community. The tax revenues as well as the permanent job creation had not been finalized in the early stages. I sought to better understand the issues from both those in favor of the plant, lead primarily by the Development Authority, and the opponents who had organized into a group know as "The Friends of the Chattahoochee". I attended meetings with "The Friends of the Chattahoochee" to listen to their claims. Some of their concerns seemed to me to be reasonable but most were extreme and far-fetched and without any factual basis whatsoever. I discussed this project with members of the Development Authority and the County Commission. I studied the "Tax Agreement" between Early County and LS Power. I reviewed the Economic Impact Study done by Dr. Mac Holmes of Troy State University but found it to be poorly constructed as it did not consider the cost, both in real dollars for services required, and in potential environmental damage from the location of the plant in Early County.

I followed up on the board resolution from the Medical Association of Georgia Against coal fired electrical plants. This resolution was referred to in both public meetings in October and November. I reviewed the resolution and noted that it included no reference

to support the specific claims included in the report. Following last week's public meeting, I spoke with several Sierra Club members. They had the report but could not provide the reference material for the allegations. They assumed the resolution was accurate but had made no effort to investigate the sources of the data. I determined that only two local physicians are members of the Medical Association of Georgia. I spoke to one member about the resolution. He was not aware of it and offered to write a letter of support for LS Power. One local physician, Garret Bennett, spoke in favor of issuing the permits at the public meeting in October.

Finally, contrary to statements made at the last public meeting by Mr. Torre Mills, an African American and Blakely City Council member, LS Power will be a great benefit to African Americans in our area. This plant will, without question, expand our local economy and provide a stable ad valorem tax base essential to our local public schools. The majority of our elementary and middle school children are African American and stand to benefit more than any other segment of our population from our public school system. Jobs will be available for African Americans both during the construction period and for the operation of the plant. In fact, the African American businessmen and women in our area vigorously support LS Power. They understand the economics of this issue.

Numerous African Americans wore "Support LS Power" buttons at both public hearings. Mr. Mill's comments were inaccurate and did not represent the majority of the African American workforce in Early County.

Although I acknowledge that there will be some negative impact to the environment from this plant, I believe that the damage will not be significant or burning of coal to generate electricity would not be allowed in this state. As I see it, the only group without an agenda in this proposal is the Georgia EPD and you have more expertise in this matter than the rest of us combined. It is your job to make certain that this plant meets all the requirements of the law and we trust you to do that. It is on that basis that I can live with the negative environmental consequences.

I am almost positive that if this subject came before the voters in the form of a referendum, over 90% of our Early County voters would vote for approval. When I announced my candidacy for County Commission this past spring, I sent a letter to every registered voter in my district. In that letter I make it clear that I supported LS Power's coal fired electric generating plant in Early County. I was elected by a favorable vote of over 82%. Although my election was not a referendum on the power plant, I think that if the people of my district were not in favor of it, my vote count would have been far less. The power plant will be located in my district.

I appreciate the extensive process that is required to permit a facility such as this and the job you do to make certain that the rules that are established are followed. Due process has certainly been allowed, so I encourage you to approve the applications without delay so that LS Power can begin construction as soon as possible.

Comments from Apalachicola Riverkeeper

On behalf of the 900 members, the Board of Directors and the Executive Director/Riverkeeper of the Apalachicola Riverkeeper, I submit the following comments on the issuance of the proposed water withdrawal permit for Longleaf Energy Associates, LLC (LEA) and modification of the water withdrawal permit for the Great Southern Paper Company (GSPC).

The Apalachicola Riverkeeper opposes the issuance of the proposed permits. The Apalachicola Riverkeeper is opposed to increased industrial withdrawals from the Apalachicola-Chattahoochee-Flint (ACF) system. Under the proposed permitting scheme, the water proposed to be used by the Longleaf Energy plant will directly or indirectly come from the Chattahoochee River and will, in large part, not be returned to the river and the small percentage that is returned will be in poorer condition than when withdrawn.

By this letter and by the approval and permission of the Turner Environmental Law Clinic, the Apalachicola Riverkeeper joins, incorporates and hereby adopts the comments submitted by Larry Sanders, Staff Attorney for the Turner Environmental Law Clinic dated 6 November 2006 regarding the application for issuance of the Longleaf Energy permit and modification of the Great Southern Paper Company permit.

In addition, the Apalachicola Riverkeeper submits the following:

78. Comments related to Proposed Permit No. 049-1295-03, Longleaf Energy Associates, LLC

a. First, the ecological and economic viability of the flora, fauna and human communities in the Florida portion of the Apalachicola-Chattahoochee-Flint River system) ACF depend on the consistent provision of proper quantities of water in the Apalachicola River. In addition, these same communities need clean water to function in a healthy, productive and sustainable manner. By the terms of proposed permit no. 049-1295-03, under certain conditions, LEA will be able to take its entire water supply from the Chattahoochee River. In what seems to be the normal course of events, i.e. when Special Condition 2 is not in effect, LEA will be able to routinely satisfy 58% of its water needs from the Chattahoochee. Finally and most important, through Special Condition 9, the Environmental Protection Division (EPD) will allow LEA and GSPC to transfer water from the Chattahoochee into other basins.

Response: This comment was apparently based upon an incorrect interpretation of Special Condition 2. The Longleaf water use will actually be as follows: As long as Great Southern Paper Company (GSPC) produces treated wastewater and non-contact water, Longleaf will get approximately 42% of the water demand from GSPC treated wastewater and approximately 58% of the water demand from GSPC non-contact water. If Longleaf cannot use the GSPC treated wastewater, then Longleaf will get all of its water demand from the GSPC non-contact water. If GSPC cannot produce enough non-contact water to meet the Longleaf water demand, then Longleaf will withdraw water from the Chattahoochee River. At that time, GSPC will not be withdrawing water from the Chattahoochee River.

In response to the comment concerning Special Condition 9, the condition is being changed to prohibit transfer of water to other entities. The Longleaf Surface Water Withdrawal Permit Special Condition 9 is being changed from "The LEA shall not transfer any water withdrawn via this Permit to any entity operating outside the Chattahoochee River basin without the EPD approval of such a transfer." to "The LEA shall not transfer any water withdrawn via this Permit to any entity."

b. The Apalachicola Riverkeeper opposes increased withdrawals from the Chattahoochee River. Likewise, the Apalachicola Riverkeeper opposes increased withdrawals from the Chattahoochee River for operations, such as the proposed coal-fire power plant, when the effluent returned to the river will be of a lesser quality than the water originally withdrawn.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. EPD has determined that there is no reasonable potential for the proposed discharge to cause or contribute to an instream excursion above narrative or numeric water quality criteria. The Chattahoochee River is classified as a warm water fishing stream at this location and this use is expected to continue to be supported after the proposed discharge commences.

c. As to Special Condition 9, is the EPD blind to the ongoing negotiations, litigation and conflict between the sister states, Florida and Georgia, regarding the allocation of the waters of the ACF? This condition should be excised from the permit. If allowed to stand, the EPD is opening the door to further expensive, wasteful litigation on the ACF. What could possibly be the impetus for such a condition other than LEA's or GSPC's desire to increase its revenues through the sale of water that rightfully should travel into and through the communities of the Apalachicola River system. EPD is aware that during the drought of 2006, thousands of endangered mussels, organisms, which if located in Georgia would come under the EPD's duty of care to protect, were killed by the reduction in flow through Jim Woodruff Dam. Finally, we demand that the EPD publish the exact conditions and considerations it will use and make in contemplating a transfer of water outside of the Chattahoochee basin.

Response: As stated in response to comment 78a, Special Condition 9, is being changed to prohibit transfer of water to other entities. The Longleaf Surface Water Withdrawal Permit Special Condition 9 is being changed from "The LEA shall not transfer any water withdrawn via this Permit to any entity operating outside the Chattahoochee River basin without the EPD approval of such a transfer." to "The LEA shall not transfer any water withdrawn via this Permit to any entity."

d. Second, in LEA proposed permit Special Conditions 2c and 2d, the language implies that if either the "five-day biological oxygen demand (BOD-5) is greater than 120 mg/l" or the "total suspended solids (TSS) concentration if greater than 220 mg/l" then LEA could take all of its water from the Chattahoochee River; is that correct? Has EPD or the permittee calculated or can you predict how often this is or could be the actual condition of the Chattahoochee?

Response: Comment response 78a addresses the Longleaf water use from the Chattahoochee River. Longleaf reviewed the GSPS records and concluded that the use of the Chattahoochee River would not occur under any normal operations.

It is not possible to predict how often GSPC's effluent will exceed BOD5 of 120mg/L or TSS of 220 mg/L. However this condition would most likely indicate an upset at the paper mill, at which time wastewater would be diverted to emergency storage. GSPC's production would be cut and the paper mill intake would be correspondingly reduced. This allows LEA to pick up the additional direct intake water and reject the lower quality recycled paper mill wastewater as well.

e. Third, if the permit is issued, LEA proposed permit Standard Condition (4)a should also require LEA to report the sources of its water, i.e. outfall 001/002, 005 or the Chattahoochee. LEA proposed permit Special Condition 8 requires just this; however, the "in lieu" language is vague as to whether Special Condition 8 replaces Standard Condition (4) at all times. Nonetheless, this reporting requirement must report actual withdrawal sources and withdrawal amounts, not averages.

   In addition, if the permit is issued, LEA proposed permit Standard Condition (4)b should require that the maximum 24 hour withdrawal be reported **and** that all 24 hour withdrawals that exceed the 27.0 MGD maximum should be reported as well. If Special Condition 8 replaces the entire Standard Condition (4), including (4)b, then Special Condition 8 should be required to report 24 maximum withdrawals as described in the previous sentence.

Response: The Longleaf Surface Water Withdrawal Permit Special Condition 8 is more stringent than Standard Condition 4. Special Condition 8 does actually require Longleaf to report their daily (24-hour) average withdrawals for each day from each source and submit it to EPD every month. This reporting will provide all 24-hour withdrawals as well as the monthly averages.

f. Finally, the Apalachicola Riverkeeper anticipates that the NPDES permit for LEA could have lower parameters for pollutants due to the lower quality of the source water from GSPC. The Apalachicola Riverkeeper opposes and Georgia's antidegradation standards strictly prohibit any lowering of water quality in the Chattahoochee River.

Response: EPD has determined that there is no reasonable potential for the proposed discharge to cause or contribute to an instream excursion above narrative or numeric water quality criteria. The Chattahoochee River is classified as a warm water fishing stream at this location and this use is expected to continue to be supported after the proposed discharge commences.

79. Comments related to Proposed Permit No. 049-1295-01, Great Southern Paper Company

a. First, for the reasons previously explained the Apalachicola Riverkeeper requests that Special Condition 9 be excised from the proposed permit.

Response: Please refer to comment 78a of this Final Determination for more information on this topic.

b. Second, if the permit is issued, Special Condition 3 should be amended to require that the Water Conservation Progress Report be submitted before the proposed permit expires on 31 December 2009.

Response: The GSPC Surface Water Withdrawal Permit Special Condition 3 is being changed in response to this comment so that the date of the water conservation progress report will be submitted no later than the expiration date of the Permit.

c. Third, if the permit is issued, GSPC proposed permit Standard Condition (4)a should state that GSPC report the sources of its water, i.e. outfall 001/002, 005 or the Chattahoochee. LEA proposed permit Special Condition 8 requires just this; however, the "in lieu" language is vague as to whether Special Condition 8 replaces Standard Condition (4) at all times. Nonetheless, this reporting requirement must report actual withdrawal sources and withdrawal amounts, not averages,

   In addition, if the permit is issued, GSPC proposed permit Standard Condition (4)b should require that the maximum 24 hour withdrawal be reported **and** that all 24 hour withdrawals that exceed the 144 MGD maximum should be reported as well. If Special Condition 8 replaces the entire Standard Condition (4), including (4)b, then Special Condition 8 should be required to report 24 maximum withdrawals as described in the previous sentence.

Response: GSPC Surface Water Withdrawal Permit Special Condition 4 is more stringent than Standard Condition 4. Special Condition 4 does actually require GSPC to report their daily (24-hour) average withdrawals for each day and submit it to EPD every month. This reporting will provide all 24-hour withdrawals as well as the monthly averages. Also, comment 78e response addresses this for the Longleaf Permit.

e. In conclusion, the Apalachicola Riverkeeper does not believe the EPD has taken into consideration the potential impacts that increased water withdrawals from the Chattahoochee River will have on the ACF system below the intakes and outfalls of the LEA and GSPC operations.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users.

Comments from Big Bend Climate Action Team (BBCAT)

80. Our mission is to help local governments, businesses, and citizens in Florida's Big Bend to do their share to abate climate change by reducing fossil fuel use and promoting energy efficiency, conservation and renewable fuels in power plants, buildings and vehicles. We are concerned that climate disruption, caused primarily by human use of fossil fuels (especially coal), is already occurring and is rapidly becoming more severe. We are also concerned that our air and water are already seriously polluted. We know that many forms of alternative energy are available and cost-effective, and that, therefore, the growing energy needs of populations in our region can be met without resorting to the use of coal.

    For these reasons, we have opposed the construction and operation of a proposed 800-megawatt pulverized coal-burning power plant in Taylor County, Florida, since it was first proposed in June of 2005. Now, LS Power is proposing to build a 1,200-megawatt pulverized coal-burning power plant, to be called the Longleaf plant, in Early County, Georgia. We are opposed to this coal-burning power plant for the same reasons.

    Pulverized coal plants represent an outdated, polluting technology. They cannot be adapted to permit carbon capture and storage, which is needed to prevent the emission of the major global-warming gas, carbon dioxide, which is released when fossil fuels are burned. Pulverized coal plants will not be economically viable when our federal government enacts responsible carbon-dioxide emissions limits as many other nations have already done. (After this month's mid-term elections, it seems likely that responsible federal action will come sooner than seemed possible a short time ago.)

Response: Please refer to Comment 45 of this Final Determination for more information on this topic.

81. Moreover, most proposed coal-fired plants are not needed. Before a community proposes to use coal to generate its electricity, it should research and implement the full potential for two alternatives to fossil fuel use: 1) demand reduction through use of conservation and energy efficiency, and 2) generation of energy from renewable (carbon-neutral) fuels. No community in Florida and almost no community in Georgia that is proposing a coal plant has evaluated and implemented the full potential for these clean-energy alternatives, yet research has shown that they are more cost effective than either coal or natural gas. The Georgia Public Service Commission, prior to making a decision on Early County's Longleaf coal-plant proposal, should require that these potentials be evaluated.

    When the City of Tallahassee's Electric Department planners first recommended joining a partnership to build the proposed Taylor County coal plant, they were unaware that significant energy resources other than coal could be made available

to meet the City's projected need for some 250 to 300 megawatts of power over the next 20 years. Working with the City staff, the Big Bend Climate Action Team (BBCAT) recommended that the City hire expert clean energy consultants to evaluate and recommend alternatives to the coal plant.

As a result of the research and advice of these experts, the City of Tallahassee has now committed to reducing demand by 162 megawatts through energy efficiency over the next 20 years and has signed a contract for 38 megawatts of electricity from clean biomass, which will become available in 2010. With most or all of the City's energy need met by these clean-energy resources, it seems clear that the only supplementary fossil-fuel generation needed, if any, can be produced by several relatively small natural-gas plants. Natural gas emits considerably less carbon dioxide than coal, per unit of energy produced.

In our view, all utilities in Georgia should explore options such as these before building more coal plants. Furthermore, any decision to build a coal plant in Georgia should be deferred to make sure it is consistent with the soon-to-be-completed comprehensive State Energy Strategy developed at the request of Governor Perdue and likely to result in legislative changes affecting energy production.

Response: Please refer to Comment 73 of this Final Determination for more information on this topic.

82. BBCAT is also concerned about the impact of pollutants on our region's air and water. When burned, coal, even with mandated controls fully in force, emits more mercury than any other fossil fuel. Virtually all lakes, rivers, and coastal waters in our region are polluted with mercury to such an extent that health advisories have become necessary restricting consumption of fish from these waters.

Pollution of the air by particulate matter is also a problem in the Tallahassee area. According to Larry George at Florida's Department of Environmental Protection, Florida's air quality meters show Tallahassee's particulates, together with those of Pensacola and Tampa, to be among the highest in the state. George attributes the high particulate levels, in part, to pollution drifting over north Florida from coal-burners in Tennessee. Tallahassee is also downwind of Early County, Georgia, and the Longleaf plant's air pollution might well travel to Tallahassee and add to the problem.

For these reasons, we ask that all permits for this pulverized coal-fired plant be denied. There are viable clean energy options and there are better and cleaner fossil fuel approaches.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Sammy Prim – citizen of Gordon, Alabama

83. I am writing my comments to oppose the permitting of LS Power to build a coal-fired power plant in Early County, Georgia. I was not able to attend the public hearing on November 9, 2006 in Blakely, Georgia, and I summit these comments for you to consider.

From the very beginning, I have tried to present facts and be as non-emotional as I could be. As a retired physician, I know facts can get distorted by the opinion of the person from whom they come; therefore, I have tried to glean my information from the medical literature and not from those that would support my position. I again will try to summarize these and I believe these to be the best information we have in that they are corroborated by different independent studies.

These facts are in reference to the effects of silicon dioxide, nitrous oxide, and particulate matter (defined as PM10 and even more critical PM2.5) upon human health. There will between 20,000 – 24,000 deaths this year in the U.S. as a result of these toxic pollutants and 90% of these could be prevented by capping levels of these pollutants. There will be another 2800 cases of carcinoma of the lung with a mortality of near 100%. Just over 500,000 cases of acute asthmatic attacks will be precipitated by these toxic materials per year. In addition, there will be over 38,000 non-fatal heart attacks attributable to these materials per year. The average number of years of life lost as result of these particles is 14 years (i.e.: if I am one affected by these then my normal life is decreased by 14 years).

In the state of Georgia this year, there will be 35.5 deaths per 100,000 people and 38,000 acute asthmatic attacks from these particles. According to ABT Associates, the total monetized health cost of U.S. power plant pollution is a staggering $167.3 billion annually. I have stated these facts over and over, and no one seems to even acknowledge that we know them. I feel that you (EPD) do not believe these facts and think I am exaggerating. Please go to the medical literature and do some homework, on your own, as this project is too important for you to take my word, your word, or LS Power's. I urge you to do some research on your own independent of others. This is the least you can do for your part in our world.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

84. The next point I want to address is that we in Gordon, Alabama, will be the most affected by this plant. We know what pollution is; the people in Blakely, Georgia and Dothan, Alabama, simply don't know what it is like to live where we do. We know what it is to having burning eyes and skin, non-productive hacking coughs and to see particles in the air that are visible and a generalized haze. There are those in our community who had none of these symptoms prior to coming here and when we leave for any significant period of time, they are relieved. Some are home-bound when the paper mill is "bad" because of asthma and obstructive airways disease that is exaggerated by toxins.

    Yet we are told by LS Power and EPD to "trust us", for we will assure you all is well. How can you say this, are you not the one we trust to protect us from the already polluting paper mill that without doubt is harming us now? To us any more pollution is not acceptable. Our homes, cloths and cars smell like a hog barn and add this to the symptoms above is enough. I believe you when you say that we not even know this plant is there from the smell and looking at the smoke stacks, but the silent effects march on.

    The PM2.5 is already at upper limit range in Houston County, Alabama, according to ADEM of Alabama, and you did not know that until I told you earlier. How can this be when you are permitting a particulate producing machine? You need all the facts you can obtain, and still you say "trust me".

Response: EPD has complied with all requirements associated with this permitting action. The final permit for Longleaf Energy imposes very stringent emissions limits making this facility one of the least emitting coal-fired power plants ever permitted in the United States. It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

85. At the last Q&A session you said you would require LS Power to monitor the environment for 1 year while construction is going on and then it will stop. I asked why do this, but no one answered. If the levels are elevated, will you stop construction? Why not monitor and gather facts before you permit and then monitor closely after operation begins. Only the government could design such a ridiculous plan.

    Again, you say "trust me" and even one of your own on record at the Q&A said he would be glad to bring his family and live within two miles of the plant. Can you not see how you were used and manipulated by LS Power? You played right into their hands, yet you say "trust me", and we won't let industry use us.

Response: EPD is currently working with Longleaf to determine the guidelines for the ambient monitoring. The Memo of Understanding will detail the specifies and be signed at the time same time that the final permit is issued.

86. The next issue is one economics. Certain technology you said would not be economically feasible, yet when asked about other aspects of the economics of this proposed plant, you politely said you could not get involved with it. You can not have it both ways, unless you are an autonomous government body. We, in the real world, cannot live like this. Should you not stay out of the economics and do what is the latest available technology and let LS Power decide if it is viable or not? Or either you must get involved in all the economics; again, the echo "trust me". It seems to me in this area of economics the only one who can trust you is LS Power, for you said what they wanted you to say. Who do you work for? The taxpayers or the industrial powers?

Response: With regard to economics, EPD evaluates the cost effectiveness of all the possible available and technically feasible control technologies for the proposed facility. Beyond that, the comment is too vague to address further.

87. Another issue I want to address was brought up by the gracious black lady from Gordon, Alabama, who stated that 70% of African Americans live within 30 miles of a coal fired power plant. You simply stated that you had nothing to do with ethnic situations as regards to this. I would remind all of us the EPA has an environmental justice division and so does the EPD of Georgia. In states like Louisiana and California, this has become very important, and I will assure you that to the citizens of Gordon, Alabama, which is 90%+ African American, this is very important, for they see this as another way the government and big business use their poverty and lack of political power to their detriment. If this plant was proposed in Dothan, Atlanta, or Macon, there would be much more concern by all citizens. We forget and refuse to look at these issues until they are in our own backyards. This is in "our backyard".

Response: Please refer to Comment 43 of this Final Determination for more information on this topic.

88. The last issue I want to address is the most important of all, and none of use have addressed this in the open, and it is a moral one. When our environment was created, it was declared good and was set in motion by laws that govern it in a state of dynamic equilibrium. This is really hard to grasp that there is an equilibrium that is constantly changing so as to attempt to keep things the same, so we can exist. This system has been tested and stressed, but it has done a marvelous job; however, there are limits. When the factors affecting the equilibrium are shifted so far in one direction, the system fails. We now know we are headed in that direction by "global warming". Coal burning produces large amounts of CO2, which is shifting the balance. No comment to CO2 had been made except very superficially. Are you not concerned? Anything we do to make this environment not as good as it is finds us against the Creator and being selfish for the next inhabitant of this plant. In the future, I fear that those who follow us who have to live in what we leave will see us as their terrorist and not the likes of Osama Bin Ladin.

How then can we willingly allow a less than best coal-fired power plant to be permitted and built when we know what we all know? This would never have come about had President George W. Bush never written his directive that we need over 300 "non-polluting" coal-fired power plants in the U.S. over the next several decades. How can this be, for there is not such thing as a non-polluting coal-burning anything? Again, the refrain "trust me". We must listen to all of creation that will come after us and protect them from the added burden of more pollution, even if it means we may have to learn to live a different life style. We must ask ourselves, is my way of life more important than anything? No one else can inherit it or carry it on if we continue on this path for it cannot sustain itself in this dynamic equilibrium.

Can we here the cry of the unborn, our children, grandchildren, and future generations saying "they knew better, how selfish they were"? Can we not hear the anguish of a life of a child mentally challenged by the 220 lbs of mercury this plant will put into the environment every year?

Maybe the grief and hardship when a family loses a mother or father to death caused by the toxic pollutants from this plant 14 years earlier then they would have?

There is nothing we do that does not effect all because we are all connected in our existence and nothing lives out of this sacred space called existence, so how can we do anything to harm or degrade the space that is for all? We must do what is right and now what is expedient.

We must listen to all that is crying to us out of one reality with the tears of our hearts, not with the greed of our minds and lacks of resolve. We have nothing to fear but ourselves when we condemn our existence for a fist-full of dollars.

> I beg you out of the bottom of my heart to dig deep into your being and for once, do what is right no matter the cost, for if you do, so you will gain your very being. Dear God let it be.

Response: Please refer to Comment 84 of this Final Determination for more information on this topic.

Comments from Richard Furman – citizen of Miami, Florida

89. Attached please find my presentations that I have given in Texas and Florida as an expert on PC and IGCC Plants. The same facts apply to the proposed Longleaf Plant. I believe that IGCC should be considered as BACT for all PC plants. My presentation demonstrates that IGCC is commercially available and provides significantly lower emissions at about the same costs as PC plants. Please contact me if you would like any additional information.

Response: Please refer to Comment 45 of this Final Determination for more information on this topic.

Comments from Carleen Logan – citizen of Blakely, Georgia

90. Today, November 9, 2006, THE ATLANTA JOURNAL-CONSTITUTION said NO! IT'S NOT WORTH THE TRADE-OFF- Please LISTEN!

Please DO NOT permit the proposed construction of the coal-fired plant in Early County.

My family and I OPPOSE the potent toxins of Mercury, carbon dioxide and especially the high levels of particulate matter that causes asthma, heart attacks, lung cancer, and premature deaths. I have two grandchildren with asthma and one has to take breathing treatments daily. Even your own EPD statistics prove that toxins from coal-fired plants make people sick.

Please don't forget that Early County is already #10 in the state for industrial pollution because of the Georgia-Pacific paper mill plant. We already have enough sick people on both sides of the river.

My family owns 800 acres of riverland within a few hundred YARDS from the proposed site. This coal-fired pollution will devastate this area. My family has owned and protected the river-land, water, and wildlife for over 60 years. My grandfather and his neighbors organized a wildlife preserve over 60 years ago. We have turkey, deer, raccoons, beavers, foxes, alligators and birds of all kinds including a Bald Eagle which has her nest on the land joining our property. The mother and her young fly to & from our land. We also have a long list of endangered species of birds that live in our forest. The forest land on the Chattahoochee River throughout Georgia is dwindling fast. Please don't destroy the little that we have left.

Response: Please refer to Comment 77 and 105 of this Final Determination for more information on this topic.

91. The CHATTAHOOCHEE RIVER is special! Don't allow it to be contaminated. The Chattahoochee River serves thousands of people in Georgia, Alabama, and Florida. You can stop the tri-state water wars by supporting the environment and STOP the permitting to pollute.

Response: EPD acknowledges and understands the comments about the potential human health and environmental impacts that could be associated with this project. EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of these permits.

92. The mercury that this proposed plant will emit, will also be devastating to our 60 year-old fish pond. Through the years family, friends, Boy Scouts, civic and church groups have all enjoyed the fishing and camping at this site. Will future generations who use the pond and the river be plagued by birth defects and premature deaths? How many are going to have to suffer? Who is going to pay for the medical cost?

    EPD needs to listen to the ATLANTA JOURNAL-CONSTITUTION and to the Georgia and Florida Medical Associations. EPD needs to step up and help the state of Georgia protect the environment and help slow down Global Warming. Please DO NOT PERMIT this coal-fired plant in Early County, Georgia. It is not worth 100 jobs. It is a moral decision that will affect the quality of life for generations to come.

Response: The final permit for Longleaf Energy imposes very stringent emissions limits for mercury emissions making this facility one of the least emitting coal-fired power plants for mercury ever permitted in the United States. In addition, the EPD recently adopted rules requiring significant reductions in mercury emissions from all existing coal-fired power plants in the entire state. Overall, state-wide, mercury emissions will be decreasing significantly.

Comments from Robert Claude Bell – citizen of Blakely, Georgia

93. I am opposed to the proposed LS Power Coal-Fired Power Plant in Early County, Georgia. Damaging the environment by burning coal is unacceptable to me, particularly when alternative energy generating sources are available.

    I am very concerned about the toxic chemicals that will be produced during the operation of the coal fired plant and how the toxic emissions will damage my health and the health of those who live in a widespread area surrounding the plant.

    The Chattahoochee River and the clean environment in Early County are our greatest assets and present the greatest opportunity for economic development in our area.

    I respectfully ask the EPD to refuse to permit the LS Power Coal-Fired Power Plant in Early County, Georgia.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Cynthia Patterson – citizen of Marietta, Georgia

94. Please accept these comments opposing the Longleaf Energy Station coal-fired power plant proposed for Early County.

Although the plan will provide 100 jobs in an area of 7% unemployment, the environmental cost is too high.

Two hundred pounds of toxic mercury will be released. Ten tons of carbon dioxide, which contributes to climate change, 3,7000 tons of nitrous dioxide and 6,400 tons of sulfur dioxide will pollute the air. Particulate matter will travel hundreds of miles downwind.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

The Chattahoochee River will be used to dump 5 million gallons of wastewater, daily. It will consume 20 million gallons of water, at a time when drought and the water needs of Florida and Alabama indicate we should be using less water, not more.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comment 91 of this Final Determination for more information on this topic.

Comments from Gary Henderson – citizen of Marietta, Georgia

This letter is in support of the permitting and construction of the Longleaf Power Station near Hilton, Georgia. As you know, there are very few locations where a coal-fired power plant can be permitted, and Hilton is one of those locations.

For Georgia to continue to grow, we will need all the power we can generate that does not require natural gas. I know that I do not need to tell you that natural gas is on of the few fuels that can be delivered and burned in small quantities without air emission controls. We must conserve our natural gas for home and industrial uses and generate electricity with those fuels whose emission controls can be economically installed at large facilities capable of spreading the capital cost of those controls over many years of continuous electrical output.

Instead of condemning this plant as a Faustian bargain as the Atlanta Journal did in their editorial on this project, the plant should be held up as a model for future coal fired power plants. The reuse of gray water from the paper mill across the highway and $400 million in state-of-the art air emissions control equipment proves Georgia to be a leader in balancing the needs of man with his environment.

I ask that you support approval of the permits for this project and then tout the facility as a victory for Georgia's future.

Comments from Leigh W. Brooks, Ph.D. – citizen of Albany, Georgia

95. I read in the Albany Herald that you wanted public comments on a coal-fired power plant that may be built in Early County. I am very opposed. Early County is downwind of Albany and coal pollutes the air. One real benefit to living in Albany is the lack of pollution. We have such good air here, especially as compared to places like Atlanta. Please don't built something that will ruin one of the main benefits to living in Southwest Georgia.

    There are other ways, safer ways, to generate energy. Another benefit to living here is plenty of sunshine. Solar power technology has come a long way and will generate electricity without pollution.

Response: Please refer to Comments 45 and 77 of this Final Determination for more information on this topic.

Comments from Mr. & Mrs. William Movath – citizens of Tyrone, Georgia

In response to the invitation to submit our comments concerning the Longleaf Energy Station proposed in Early County, my husband and I would like to say that we are "all for it." Any American would welcome independence from foreign oil and a return to a land of plenty and lower energy prices. With 20% of the total cost of the facility being invested in environmental control technologies, the people of Georgia can be confident that the environment will be protected. We are encouraged by this project and want to give it our blessing.

Comments from Edward C. and Lucia K. Driggers – citizens of Dothan, Alabama

96. We are tree farmers in Houston Co. Alabama with a hunting club that leases our land for hunting. We are concerned about the proposed coal burning power plant to be built on the Chattahoochee River.

The pollution from this plant would be carried by wind currents to all areas of our county and to others. This pollution will have an adverse effect on our flora and fauna. The fauna depend on the flora to survive and thrive. Our pine trees will suffer from arrested growth thus affecting our livelihood.

Response: Please refer to Comment 105 of this Final Determination for more information on this topic.

Studies of the aquifer in our area have shown such depletion that we will need surface water reservoirs in the near future. Since the plant will use millions of gallons of water dial and much of this will not be returned to the river, this will stretch our already challenged waterways. Our air is already saturated with pollution or near saturation as shown by a monitor. Please say "no" to a plant that will be detrimental in so many ways.

Response: Please refer to Comments 91 and 105 of this Final Determination for more information on this topic.

Comments from Alice W. Benborki – citizen of Albany, Georgia

97. We must protect our citizens from mercury, etc. that can cause asthma, heart attacks, etc. Please do not allow the coal fired plant to be built in our state of Georgia. Thanks to an announcement at the Albany Woman Club today and to the article in the Albany Herald of today, I became aware of this threat.

Response: Please refer to Comment 77 and 84 of this Final Determination for more information on this topic.

Comments from Panhandle Citizens Coalition, John Hedrick

98. On behalf of the Panhandle Citizens Coalition, we'd like to let you know our chapter opposes the proposed coal-fired power plant in Early County. The U.S can lead in the energy arena by undertaking aggressive conservation measures and promoting partnerships to pursue clean, renewable energy alternatives such as wind and solar.

    A close approximation of the natural flow regime must be retained in the Chattahoochee River to ensure healthy ecosystem downstream both in and along the Chattahoochee and Aplalachicola Rivers and in Apalachicola Bay and its environs. Nature as well as Florida's fishery and Gulf economy are dependent upon it. Enormous water withdraws are exploitative of downstream neighbors and are not acceptable. Investments in a healthy environment today will pay incalculable dividends in the Southeast U.S. in years to come.

    If wind and solar sound like a "man-on-the-moon" assignment, we need to, indeed must, rise to the challenge. We will be followers now, as other developed nations are ahead of us, but we can be leaders, and we much shift gears into that mode of operation and thought. New tech is always pricey, but with applications and competition, the cost always comes down (some of us recall the hand-held calculator story). Also, as with the man-on-the-moon mission, spin-offs would provide unanticipated future benefits, many of which we all take for granted daily because the space race provided them.

    We are the beneficiaries of so much free energy that it's unconscionable not to partner in the pioneering of reduced-cost delivery systems and begin to take advantage of so much free energy entering earth's system every second.

    Thank you for this public comment opportunity and should you need or desire any further information or discussion with us, please do not hesitate to contact us.

Response: Please refer to Comments 45 and 77 of this Final Determination for more information on this topic.

Comments from Florida Chapter, Sierra Club

99. On behalf of the Florida Chapter, Sierra Club, with over 30,000 members, we'd like to let you know our chapter opposes the proposed coal-fired power plant in Early County. The U.S can lead in the energy arena by undertaking aggressive conservation measures and promoting partnerships to pursue clean, renewable energy alternatives such as wind and solar.

    A close approximation of the natural flow regime must be retained in the Chattahoochee River to ensure healthy ecosystem downstream both in and along the Chattahoochee and Aplalachicola Rivers and in Apalachicola Bay and its environs. Nature as well as Florida's fishery and Gulf economy are dependent upon it. Enormous water withdraws are exploitative of downstream neighbors and are not acceptable. Investments in a healthy environment today will pay incalculable dividends in the Southeast U.S. in years to come.

    If wind and solar sound like a "man-on-the-moon" assignment, we need to, indeed must, rise to the challenge. We will be followers now, as other developed nations are ahead of us, but we can be leaders, and we much shift gears into that mode of operation and thought. New tech is always pricey, but with applications and competition, the cost always comes down (some of us recall the hand-held calculator story). Also, as with the man-on-the-moon mission, spin-offs would provide unanticipated future benefits, many of which we all take for granted daily because the space race provided them.

    We are the beneficiaries of so much free energy that it's unconscionable not to partner in the pioneering of reduced-cost delivery systems and begin to take advantage of so much free energy entering earth's system every second.

    Thank you for this public comment opportunity and should you need or desire any further information or discussion with us, please do not hesitate to contact us.

Response: Please refer to Comments 45 and 77 of this Final Determination for more information on this topic.

Comments from Lawrence King, Deblar & Associates, Inc.

100. Among the reasons for my submittal to DNR concerning the LS Power Group plan to construct a coal-fired plant in Early County was the experience I gained from developing advanced fossil fueled energy systems technologies.

I am confident that the selection of combustion technology and post combustion processes by LS Power incorporated choices that combined the best alternatives of emissions limitation, availability and cost. Nonetheless, my concerns for the health and well being of the residents of Early and surrounding counties compelled me to bring to your attention the absolute need to consider the impact on residents who may be at risk due to their economic status or ethnicity.

The decision process must, in my opinion, value the impact this proposed plant may have on stakeholders whose concerns and interests may not be fully appreciated. I trust you will be kind enough to let me know if DEBLAR & Associates can help develop information that may not be readily available to the Environment Protection Division in this matter.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Tom Bell, Friends of the Chattahoochee – citizen of Blakely, Georgia

101. I am submitting these comments pertaining to the Longleaf coal-fired power plant in Early County.

LS Power, along with our local economic development authority, have touted this plant as being the cleanest technology possible. This is not true. IGCC would be BACT. Both LS Power and our development authority promoted the recycling of the fly ash. Now, the Longleaf permit states that the technology they have chosen prohibits the recycling of the fly ash. That means more ash for the landfill and more chances of contamination of wetlands and water supplies.

As I stated orally, there are already fish advisories for mercury within 2 miles of the proposed site in the Chattahoochee River. (Lake Andrews) GA EPD said at the 1st Q&A that there were no advisories for this section of the river. Adding over 200 pounds of mercury to the air every year for 50+ years is not acceptable. GA EPD stated that they don't know how this extra mercury will affect the environment. GA EPD also stated that if they saw there was a problem in the future, they would look at it. Issuing more fish advisories is not the solution. GA EPD needs to go back to the drawing board on this one.

Response: Please refer to Comment 92 of this Final Determination for more information on this topic.

Comments from Thomas Bell – citizen of Blakely, Georgia

102. My comments consist of several questions:

1) Are the State of Georgia environmental laws so weak that and antiquated coal plant such as LS Power is proposing would be allowed to be built. The technology they have proposed is over 20 years old. What about the coal plant in Tampa, Florida? LS Power says it's too expensive to build one like Tampa. We the citizens of Early County are the ones who will pay. Our health and the health of generations to come will pay for this contamination. How can you and the EPD permit something like this? Why should LS Power care what happens to us, they will sell this plant to someone like the Southern Company and move to the next poor suckers.

Response: Please refer to Comment 45 of this Final Determination for more information on this topic.

2) GA Pacific's pulp plant is 44 years old. What happens when they decide to close or sell out (they already have sold to Koch) and the dirty water? They are supposed to pump to the coal plant stops? I suppose you folks at the EPD will have to keep permitting the paper mill to keep the coal plant going. You folks as setting us up in Early County for a lifetime of pollution.

Response: The Longleaf Surface Water Withdrawal Permit Special Condition 10 addresses your concern of what happens if GSPC closes. The Special Condition 10 states "If at any time the GSPC permanently ceases to operate and ceases to withdraw water from the Chattahoochee River (Permit # 049-1295-01), the LEA may withdraw water directly from the Chattahoochee River as their primary source of water. At that time, LEA will no longer be required to use GSPC's wastewater and/or non-contact water. The LEA may make application to transfer the intake location a short distance upstream so the intake will be closer to the plant site."

3) What information do you have that shows we need additional electrical generation for GA. Why should GA residents be polluted for a bunch of retired Yankees in Florida. My family has property that joins the proposed coal plant site. We have Farley Nuclear Plant directly across the Chattahoochee River in Houston Co., Alabama, Georgia Power transmission lines running north & south thru our property, and the huge lines running east and west on our northern property line from Farley. We asked our local Three Notch co-op and they wanted $7,000 to run the line. You would think with all the kilowatts running thru us we could get enough for one light bulb. Guess what? We have a Honda generator for electricity. Don't that say a lot about us taxpayer's rights!

Response: Please refer to Comment 73 of this Final Determination for more information on this topic.

4) What idiot decides to permit a coal plant directly across the river from a nuclear plant? Has the EPD ever heard of Homeland Security? If a problem arises at the nuclear plant I suppose the folks at the coal plant will continue shoveling coal. Maybe the Southern Company had a little to do with this situation. Seems to me you folks at the EPD are increasing the size of the target.

Response: Georgia EPD has no authority over the location of a new plant such as this. All plant development details are handled by the parent company and in this case LS Power Development, LLC.

I look forward to your response to my questions.

Comments from Jennifer Horton – citizen of LaGrange, Georgia

103. I want to strongly urge you and the state department to reconsider your plans to build a coal plant in Early County, Georgia. Coal plants are among the worst polluters in the country, emitting tons of greenhouse gases every year. The last thing we need is another one to add to the problem of global warming.

In fact, the era of coal is probably ending. The U.S. is likely to impose curbs on greenhouse gases in the near future, which would effectively bring a cost to the emission of carbon dioxide. Evidence suggests the cost could be anywhere from $20-$25 for a ton of carbon dioxide released. Thus, the price of coal could leap, negating any benefits you are currently contemplating. With curbs on greenhouse gases, the cost of producing electricity with coal could raise by 50%.

Coal plants are the easy answer to the US need for electricity, but the costs are enormous. People's health, our oceans and streams, and the air are only a few things negatively affected by the output of coal plants. The nation's need for clean energy is stronger than ever. Solar energy, wind energy and other clean sources are moving to the forefront. Before you build a destructive coal plant in Early County that has the potential to spread tons of destructive gases all over the entire state and neighboring areas, please consider the consequences. The so-called clean technologies that are required by the state for the plant to meet emissions requirements are not enough. Even if the potential price increases do not deter you, the cost to the environment and the health of Georgia's citizens should. Georgia simply should not have to bear another contributor to its smog.

Please say not to the Longleaf Coal Plant. Consider going solar instead; the interest generated by such a move could bring real potential to the state.

Response: Please refer to Comments 45 and 77 of this Final Determination for more information on this topic.

Comments from Tom & Connie Bell, Friends of the Chattahoochee - citizen of Blakely, Georgia

104. I am submitting the following comments pertaining to the Longleaf Energy coal-fired power plant proposed for Early County.

Longleaf has had 6 years to install air monitors in addition to their modeling. The GA EPD could have required them to install air monitors, but chose not to. If this plant is permitted, the GA EPD should require Longleaf to monitor the air forever, using real-time data accessible via the internet.

Response: Please refer to Comment 85 of this Final Determination for more information on this topic.

There is a PM 2.5 monitor in Houston County, Alabama. This monitor has been almost at the maximum (13) for the last 3 years. This monitor is picking up G-P's pollution, which is 4 miles from the Longleaf plant.

Response: Please refer to Comment 85 of this Final Determination for more information on this topic.

Residents of Gordon, Alabama have pleaded with the GA EPD for years to do something about the pollution that's already coming from G-P. The fallout from G-P is already affecting the health of the people as well as the animals in this area.

If this plant is permitted, Longleaf will burn 27 times more coal than G-P already does. This area cannot and should not have to suffer the burden for electricity that will most likely go to Florida.

As adjacent landowners next to the landfill site on the North and South, we demand that more monitors be placed along all sides of the landfill and plant site and that baseline readings be taken in our drinking well, ponds fish and vegetation.

Response: Please refer to Comment 84 of this Final Determination for more information on this topic.

Comments from Marabeth Farmer – citizen of Apalachicola, Florida

105. Please add my name to the list of citizens opposed to the construction of the proposed massive coal-fired power plant in the pristine forests of southwest Georgia. It is my understanding that "this plant will emit 10 million -15 million tons of carbon dioxide annually, the greenhouse gas causing global warming. This is the equivalent of adding 1.5 million new cars on the roads. It will emit 220 pounds of mercury per year, most of it eventually ending up in our rivers, lakes and streams where it could contaminate more fish."

Response: EPD is concerned about pollution from coal burning power plants. Assessments have been conducted to ensure that most kinds of pollution released from the proposed power plant will be below amounts that will significantly impact the environment. However, assessing the impact of mercury released into the atmosphere from burning coal presents unique difficulties. Studies have shown that air transport and deposition, followed by movement into aquatic systems through runoff and other mechanisms can significantly affect the potential for bioaccumulation of mercury in fish. Exposure to mercury from consumption of contaminated fish is considered to be the major pathway of exposure for people.

EPD has evaluated the potential for Hg air emissions from the proposed power plant to accumulate in the Chattahoochee river system and other nearby river basins and affect fish tissue concentrations of mercury. However, there is much uncertainty in the models used and our understanding of transport mechanisms. At present, the results of such analysis have yielded inconclusive results.

Georgia EPD's APB and WPB are coordinating with the Georgia Wildlife Resource Division to develop a statewide network for trend evaluation of mercury in fish tissue. This will provide a basis for evaluating the effects of The Clean Air Mercury Rule and other reductions in mercury use on mercury concentrations in fish tissue.

> I am a property owner in Spalding County GA where I was born, and a resident of Apalachicola, Florida. The mercury waste from this plant going into the Chatahoochee River then into the Apalachicola River and Bay would pollute the waters so that the estuary, fish, oysters and other foods from the bay would not be edible. Needless to say, all of the Chatahoochee's water would be polluted and fish not edible and/or dying! AND loosing a flow of 20,000 gallons a day of water would be deadly for the Apalachicola bay and communities down river!

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comment 91 of this Final Determination for more information on this topic.

> I am appalled to learn that this is even being considered with all of the evidence that this would further destroy our environment. Having just read, Ecology of a Cracker Childhood by Janisse Ray, which refers to the long leaf pine forests, I am especially sensitive to the need to save what we can of our natural forests, land and waters!
>
> I hope that those with the power to do so, will stop this project NOW…no further discussion. We have to find clean ways to produce energy, and ACT to conserve what we have!

Response: Longleaf was required as part of their application to evaluate the effects on soils and vegetation. EPD believes their will be no adverse impacts on the natural forest due to the facility.

Comments from Ryan Means – citizen of Tallahassee, Florida

106. I am a biologist, Floridian, and lover of the Apalachicola-Chattahoochee-Flint river system. Sir, I am writing to respectfully urge you to not support the building of a new coal fired power plant on the Chattahoochee River. I urge you to consider a more environmentally friendly power options, such as development of solar and wind power. We also should consider teaching people to conserve their energy in a myriad of ways.

What is really important that we, as humans living in this fragile world together, should consider is how will we leave this beautiful unique planet to our kids? Will we destroy all things natural, wild, and free just so we can turn on another light bulb in our houses?

Shame on us if we let our kids inherit an ugly, ravaged, polluted world we live in. We must keep wild places wild forever and not even consider crossing the line for any reason.

A coal plant is destructive to the atmosphere, adds to global warming issues, will rob water from the already imperiled Apalachicola River, and will discharge 220 lbs of toxic mercury into the air each year. Not to mention, it will be an eye soar for people who enjoy the natural beauty of the river.

Sir, if you have kids, or any loved ones for that matter, then consider them living in a ruined unnatural world. It is unthinkable. If you have any say so in this matter, and I was informed that you do, then please do not consider the coal plant option for power. Thank you very much for you consideration.

Response: Please refer to Comments 45 and 77 of this Final Determination for more information on this topic.

Comments from Julian Powell, Chemical Engineer - Zentech

107. I am writing in regard to the air permit application for the proposed Longleaf Power Station in Early County.

The technology used for electrical power generation (pulverized coal or PC) at this facility is nearly obsolete due to the recent scaling up and widespread adoption of coal gasification technology, Integrated Gasification Combined-Cycle or IGCC. The first utility scale IGCC facilities in the United States, one in Tampa, FL and one in California, each 250MW capacity, have been operational for over ten years now.

A number of utilities have embarked on increasingly larger IGCC generating units including, but not limited to the Atlanta based Southern Company's 400MW plant under development in the Orlando FL area, American Electric Power's two 630MW units in West Virginia and Ohio.

IGCC offers significant environmental advantages over PC and comparable costs. Typical emission reductions vs PC with Best Available Control Technologies are as follows:

mercury: 95%
NOx: 50%
CO2: 12%
SO2: lower than PC
particulates(PM2.5): virtually none

In addition to the ash generated by IGCC is in a vitrified (glass-like) form that can be recycled as aggregate for concrete, as opposed to the fly ash from PC units that is landfilled and presents a potential groundwater contamination threat.

It would be grossly irresponsible to issue and air permit for obsolete power plant technology that will adversely affect regional air quality for several decades. Any air permit missed for the Longleaf facility should hold it to the strictest economically achievable emission levels as demonstrated by IGCC.

Response: Please refer to Comment 45 of this Final Determination for more information on this topic.

Comments from Linda Jamison, Big Bend Group of the Florida Chapter, Sierra Club

108. On behalf of the Big Bend Group of the Florida Chapter, Sierra Club, 11 counties in Northwest Florida, I'd like to let you know our group opposes the proposed coal-fired plant in Early County. The U.S. can lead in the energy arena by undertaking aggressive conservation measures and promoting partnerships to pursue clean, renewable energy alternatives such as wind and solar.

A close approximation of the natural flow regime must be retained in the Chattahoochee River to ensure healthy ecosystem downstream both in and along the Chattahoochee and Apalachicola Ricers and in Apalachicola Bay and its environs. Nature as well as Florida's fishery and Gulf economy and dependent upon it. Enormous water withdraws are exploitative of downstream neighbors and are not acceptable. Investments in a healthy environment today will pay incalculable dividends in the southeast U.S. in years to come.

If wind and solar sound like a "man-on-the-moon" assignment, we need to, indeed must, rise to the challenge. We will be followers now, as other developed nations are ahead of us, but we can be leaders, and we much shift gears into that mode of operation and thought. New tech is always pricey, but with applications and competition, the cost always comes down (some of us recall the hand-held calculator story). Also, as with the man-on-the-moon mission, spin-offs would provide unanticipated future benefits, many of which we all take for granted daily because the space race provided them.

We are the beneficiaries of so much free energy that it's unconscionable not to partner in the pioneering of reduced-cost delivery systems and begin to take advantage of so much free energy entering earth's system every second.

Response: Please refer to Comments 45 and 77 of this Final Determination for more information on this topic.

Comments from Marylyn Blackwell – citizen of Wewahithcka, Florida

109. I would like to submit my objections to the proposed construction by the LS Power Company of a new Coal Power Plant on the Chattahoochee River.

Contaminants in our environment are increasing to the point that our health, the health of wildlife and the environment at large is becoming more and more hostile.

Our group members live in Florida on and near the Apalachicola River. The proposed plant will cause added contaminants, far removed from the project site. It is disheartening to know that an agency which you represent would even consider this proposal.

The decline in the health of our children, the projection that they will not live as long as their parents, the increase in the number of children with mental and emotional problems and the decrease in intellectual abilities are all related to contaminants present in their environment. The goal should be to decrease the amount of pollutants rather than to increase them. Will there be an EIS conducted for this project?

I would like to request to be notified of any future developments related to this issue.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Barry G. Parsons, Madison Environmental Committee – citizen of Madison, Florida

110. I am a resident of Madison County, Florida, where I head the 33 member citizens group, the Madison Environmental Committee. We oppose the proposed coal plant in Blakely, Early County, Georgia.

The absurd and dangerous proposal for a gigantic coal plant in Early County will be an environmental and public health disaster, here, downstream and downwind, in north Florida.

As you know, the Georgia code has provisions requiring consultation with adjacent states that would experience a regional impact from undertakings in the state of Georgia. Where is the evidence of that?

Response: Georgia's Rules for Air Quality Control do not require EPD to consult with adjacent states. Georgia EPD has been working with Alabama, Florida, North Carolina to ensure that each of those states is aware of the project and ask for their departments input to make certain that the entire region is permitting coal fired power plants in a consistent manner.

We need you to understand, from intensive study and research over the past year on our own controversial coal plant proposal in Taylor County that the negative health consequences are abundantly documented, unavoidable with coal plants, and thus unacceptable. Especially since alternative, clean sources of energy production are known, available and ready to be implemented.

In addition, we see no one looking broadly, systematically, at the substantial SAVINGS in energy use from a SYSTEM-WIDE implementation of greater ENERGY EFFICIENCY.

In Tallahassee, the Big Bend Climate Action Team did this, in an advisory role with the Tallahassee city utility, and the "megawatts" saved compensated in large part for the presumed "need" for a coal plant. We suspect the same is true elsewhere, including in Early County.

Response: Please refer to Comments 45 and 77 of this Final Determination for more information on this topic.

Beyond those consideration, we believe that you, that all of us, have a moral obligation to heed the urgent warning of climate scientist that the crisis of global warming is upon us, and that time is so short to begin massive re-working of how we meet our energy needs.

In light of these considerations, which together comprise nothing less than urgent matters of our national security, coal plants --any coal plant, anywhere—are part of the problem, and no part of the solution.

We urge you to reject this application permit and to partner with major universities and progressive energy entrepreneurs to support, to magnify, efforts to build clean energy facilities now.

In closing, I would like to suggest also that there are more than public relations reasons behind major energy companies like Excel, Cynergy and Duke Energy now endorsing mandatory limits on carbon dioxide emissions. Indeed, Duke Energy CEO Paul Anderson Supports a national tax on CO2 emissions now. And, according to award-winning journalist, Jeff Goodell ("Big Coal"), delaying emissions cuts for ten years would NEARLY DOUBLE the amount of CO2 reduction that would be required in the year 2025 for climate stabilization to even begin.

Please. Let's see some common sense, here. And some moral awareness of the common good.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Thomas M Barksdale – citizen of Woodstock, Georgia

111. Placing a coal-fired power plant in Early County surely would rank as an environmental travesty of major proportions. The proposal defies rational thought, given that the cost would so overwhelmingly outweigh the benefits. However much electricity this plant would generate, it would be a drop in the bucket toward meeting increased demand. Vigorous conservation alone would more than make up for this plant's capacity production. Add to conservation alternative sources like wind power, solar, nuclear, and biofuels and this plant would be obsolete before it is built.

All the talk about "state of the art technology" to reduce the plants pollution cannot obscure the simple fact that this plant would pore unacceptable levels of increased pollution into Georgia's environment. I understand that would annually emit more than 220 pounds of mercury, a powerful neurotoxin that accumulates in fish and the people who eat them. Every year, the plant will also generate at least 10 tons of heat trapping Carbon Dioxide and 6,400 tons of sulfur dioxide pollutants, which contribute to respiratory problems, as well as smog and acid rain. Every day it operates, Longleaf will dump 5 million gallons of wastewater into the Chattahoochee. The idea that there is some energy requirement that justifies those statistics is preposterous.

The damage to the environment caused both by its construction and by its operation would rule out its approval, even if it were being built in the middle of a vast wasteland. But to build this plant in the middle of a pristine wildlife area, in a county where hunting, fishing, and outdoor living is an integral part of the local inhabitants' lifestyles, makes it a travesty that should shock the conscience of any decent human being. The question of whether to build this plant is fundamentally a moral issue. Not all the rhetoric about energy demand and jobs and payrolls can make that fact go away. Those people focused on the presumed economic benefits will find out they have engaged in one of the most penny-wise and pound foolish decisions ever made. The idea that this plant helps solve the pressing need for economic growth in Early County is blinding them to a much better alternative. That alternative is the potential offered by a rare natural resource that Southwest Georgia possesses in abundance but, elsewhere, is becoming rarer with each passing day. I am referring to a clean, unspoiled environment coupled with a mild climate. An environment where you can be comfortable outside most days of the year and breathe without endangering your health, as opposed to conditions here in metro Atlanta, where the air pollution has created a permanent crisis with no solution in sight. Environments like Early County will become more unique as globalization turns larger portions of the globe into carbon copies of Atlanta, Los Angeles, and Washington, D.C.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

I can hear the rejoinder: ”Fine, but so what? A nice environment is great, but it does not produce jobs or an expanded tax base.” I would note, as food for thought, that the baby boomer generation is reaching retirement. The retirees will need snow-free retirement communities, golf courses, and recreational facilities of all kinds. An increasing number of affluent Americans will also need the latter. Can Florida absorb them all? All of this would take infrastructure that would take years to put in place, but in the end wouldn’t it create more than 100 permanent jobs? A huge power plant would rule out these other types of economic development that could build on, rather than degrade, the area’s environmental advantages.

The alternative that would better preserve the balance between economic development and environmental preservation was made crystal clear in a recent series of charrettes in Early County amply demonstrating Early County’s potential as a retirement and recreational center.

The economic, environmental and pollution issues demonstrate conclusively that the EPD should deny the permits to build this plant.

Response: Please refer to Comments 45 and 84 of this Final Determination for more information on this topic.

Comments from A.A. Pitrolo – citizen of Alpharetta, Georgia

112. I would like to offer my comments on the subject coal fired generation plant.

- Contrary to comments by Mr. Wiggins that "we don't have a choice" is incorrect. There is a choice that is not only better environmentally, but will yield perhaps more high paying jobs than running a coal fired plant, will produce lower cost electricity over the life of the plant, and will not be subjected to further unknowns like meeting a carbon tax which will only raise the cost of electricity to the rate payer. That system is nuclear. It behooves Mr. Wiggins and the decision makers to thoroughly study performance of ongoing operating nuclear plants, to fully understand the global warming issues, and most important to note the huge international movement to nuclear power. Clearly coal burning will be coming under more and more pressure as the Global Warming debate escalates. Why subject yourself to the coming events?

Response: Please refer to Comment 73 of this Final Determination for more information on this topic.

- Whether we like it or not the earth is heating – the cause is the subject of both a domestic and international debate. Rather than waste time arguing over its cause, it behooves policy makers, regulators (in those areas where regulator have say) to engage strategically rather than becoming victimized handling by dealing with what I call a stovepipe problem. Such has been the case for PSC's whose role is to see that payers enjoy the best value of the product, but may in my opinion failed. Here the utilities who did not want to put forth the capital necessary for producing the lowest cost electricity, elected natural gas fired units. The PSC's and the Legislature allowed the fuel costs to be separated from the process. The net result has been higher cost electricity since the natural gas demand/supply curve has changed and with that a secondary effect of higher space heating costs. A more prudent approach would have been for the PSC's to have weight averaged the industry total fuel cost/per unit of produced electricity. Then only allowed recovery of a normalized fuel cost. Such a decision would have given the utilities a choice – stay with cheap capital and "eat" the fuel cost differential or elect to spend the capital producing a more stable and lower cost of electricity. Since costs are recovered in a regulatory setting, there was nothing to lose and the rate payer afforded a better deal. Such is the case for newly considered coal plants. Right now there is a rush to commit in the hopes that they can be grandfathered from the coming carbon tax. The tax will come and there will be need to install what will be called BACT (best control technology – just as exists for today's coal fire plants) – then the obvious, back to the PSC for relief and higher cost to the rate payer. Since the future is so predictable and since the technology to capture the CO2 questionable, why allow such an open loop approach to new power plants? I recommend that anyone electing

to select a coal fired plant today not be allowed to recover future costs for new carbon reduction rules. Such an approach will not only be responsible, but will be cause for more complete planning process by all parties. Let not make the same mistake of the past.

- With respect to overall green house emissions reduction, there is only one solution. Simply stated the country needs to commit to a massive deployment of nuclear power sufficient to allow the back out of natural gas to the making of transportation fuels. Current coal fired plants should be retired (replaced by nuclear) and the coal committed to making of synthetic fuels. This approach switches one fuel from to another and by doing so not only stops the emission growth, but with accompanying conservation could yield a reduction.

If I were in the decision process and had public and/or private sector responsibilities, I would in no way consider a new coal fired power plant. The risks are just too great.

Thank you for the opportunity to express my views.

Response: Please refer to Comment 84 of this Final Determination for more information on this topic.

Comments from Robert and Karen Wildau – citizens of Atlanta, Georgia

113. At a time when we should be building a cleaner, more secure and economically-sound future by supporting energy efficiency and renewable energy, you are being asked to permit the new LS Power coal-fired power plant in Early County.

> How cruel it is that a New Jersey-based producer should take advantage of the economic desperation of this corner of Georgia by trying to stick it with such a nasty old-economy facility.

Even IF it throws out fewer pollutants than older plants, we know the harm that its mercury emissions will cause, as well as the NOx, SOx and greenhouse gases that only add to both atmospheric pollution and climate change.

There must come a time when Georgia refuses to sell the right to dirty our environment merely for the promise of a few low-paying jobs. Please just say "no" to that trashy bargain by refusing an air pollution permit for the Early County plant.

Thank you for your consideration of these remarks,

Response: Please refer to Comment 63 of this Final Determination for more information on this topic.

Comments from John Ness, M.D. – citizen of Tallahassee, Florida

114. I am a Family Physician in practice in Tallahassee for the last 20 years. I am concerned about the likely adverse health effects of another coal fired power plant. I have too many patients with respiratory illness and with cancers. I am very concerned that the contamination of burning coal causes increases in illness and deaths in my patient population.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Ronald H. Saff, M.D. – citizen of Tallahassee, Florida

115. Hello, coal plants are so dangerous that the FL and GA Medical Associations passed resolutions warning about their dangers. Coal plants in GA kill thousands alone; don't add to the onslaught allowing one in Blakely. As a physician, I know first hand the dangers of asthma attacks and how they can be deadly. Evidence is overwhelming-coal plants cause death, disease and cancer. Please don't endanger you health, Ms. Abrams, Atlanta (I presume you work there) is one of the most polluted cities. Air pollution travels for miles and miles. With each coal plant in the US (and there are approx 150 planned) shaves time off our lives and increases our cancer risk. Please don't allow this injustice. I don't want GA pollution in my city of Tallahassee; we get plenty of it from FL and GA (especially Southern Company's coal plants).

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Karen Wiloughby - citizen

116. I was told you were the contact person to accept concerns about the coal plant. We farm and have raised a family in the southeast corner of Alabama. It would be simplest to say that we are certain of the health effects of a coal plant. I have no explanation why the GA EPD has not acted on very real concerns of the irreversible health damage and question why your agency has not acted on behalf of us, the people your agency was created to protect. As you are well aware, this area also has a paper mill and nuclear plant. There has not been adequate overseeing of their effects on air and water quality. The introduction of yet another polluter can turn my business and home, as well as the community we live in, into the Sewer of the South. I have done my research and attended past public information hearings. Appearance is that it is already a done deal and that GA EPD is not doing their job. It is a difficult position to be in to know that money and politics can steamroll over our lifetime of work and investment and that I don't have a voice and those who are entrusted to speak for us won't. My daughter fought asthma until she moved but it returns when she visits home. My eyes burn when the wind shifts and I am too close to the town of Gordon. Crop and timber damage is already attributed to existing pollutants. No one in their right mind eats fish from the Chattahoochee. Doctors in Dothan are adamant about the threat of more pulmonary problems, especially in the children of our area. How can your agency not see past the short term "promise of jobs". You are selling our soul and our health and our future. All this may sound pretty dramatic, but there will be more children raised on this farm, and they will belong to me. Look at the coal plant as I do, through eyes looking at the future toward what is of lasting importance. And it is not unregulated industry. Please consider what kind of safe place you would choose for your family and friends, and would you want a coal plant pumping out the tonnage of pollutants into the air they breathe. I ask that you represent me.

Response: Please refer to Comment 84 of this Final Determination for more information on this topic.

Comments from Chris Logan – citizen of Blakely, Georgia

117. I know you guys don't care about us down here or if you did you wouldn't consider approving a permit for LS Power in Early County. Besides being highly concerned for the air that we breathe, I'm an avid fisherman. I fish within of a mile from where the proposed plant will be built. My understanding is this plant would emit up to 220 lbs of mercury per year. If it only takes a teaspoon to contaminate a couple of acres, then my pond will be a total devastation being so close to it. You can only eat a limited amount of fish from the Chattahoochee River each week. What kind of protection does the EPD stand for? What are they protecting?

    Anyway, if you permit this and LS Power builds this thing, obviously you guys are being paid off because you sure as hell don't care about the environment. Look at the smog alerts in Atlanta during the summer. Ya'll want a plant, keep it up there.

Response: Please refer to Comment 63 and 77 of this Final Determination for more information on this topic.

Comments from Gale and John Dickert – citizens of Perry, Florida

118. We want to go on record for being opposed to the coal generated power plant proposed for Early County.

We don't want any more dirty coal plants in our region. We have more than enough pollution from pulp mills and other dirty coal plants. We are supposed to be REDUCING CO2 EMISSIONS, not increasing them. There are less polluting IGCC plants and efficiency, conservation and other clean energy methods that must be implemented.

I ask Early County to REJECT this coal plant. We are fighting as hard as we can to prevent the same situation in Taylor County FL where they are trying to put 15 cities' pollution on us--another coal plant next to a paper mill.

This is a nightmare for residents who are already dying from pulp mill pollution.

Response: Please refer to Comment 84 of this Final Determination for more information on this topic.

Comments from Michael Foust – citizen of Tallahassee, Florida

119. I would like to let you know that I oppose the coal plant planned for Blakely because of its detrimental health effects on the citizens of Georgia and Florida. Particle pollution has been shown to cause heart attacks, strokes, and other illnesses that are synonymous with smoking. It would not be wise to blanket the state with more carcinogens in the air in the name of saving money on power. The facts are clear and there are many credible groups that oppose the new construction of coal plants:

* The Florida and Georgia medical associations
* Physicians for Social Responsibility
* The American Heart and Lung Associations
* Church groups in Tallahassee, Taylor County (Florida) and around Blakely (mainly Christian groups)
* Academicians at Florida State University, UF, and Georgia Tech

I implore you not to continue this plant, and weigh the benefits against the risks. Money would be better spent helping to subsidize gas prices in supply shocks, rather than be trapped in paying off a 10-15 year contract with power companies for something that will save everyone a few bucks on electricity but cost them a few hundred to thousands on health care. We already are facing a crisis in healthcare in this country, and our areas are especially hard hit by poverty, air pollution, asthma, respiratory illness, and lack of insurance. We cannot burden the healthcare system for sake of the electric grid.

Please find something else, encourage conservation, invest in solar, buy electricity from neighboring towns, whatever you must do. Even buying the entire state energy saver bulbs and mailing them to every resident would be cheaper than the plant's initial and residual effects.

Response: EPD has complied with all requirements associated with this permitting action. The final permit for Longleaf Energy imposes very stringent emissions limits making this facility one of the least emitting coal-fired power plants ever permitted in the United States. It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

Comments from Rev. Larry B. Jacobs – citizen of Adairsville, Georgia

120. I am writing this letter about the proposed construction of the Longleaf Energy Station Pulverized Coal Plant in Early County, Georgia. I was born and raised in Early County ten miles from the proposed location. My parents have lived there most of their 86 years and still live at home. I have nieces and nephews that have children under 2-years of age who live within seven miles of the proposed location. I am very concerned about the levels of pollutants that will come from this plant. I am also concerned about the transportation logistics which are not addressed in the reports. I pray that Longleaf Energy will do all that is technically and economically feasible to control pollution and provide for citizens safety.

Response: Georgia EPD's main concern is to sustain, enhance, protect and conserve Georgia's natural, historic, and cultural resources for present and future generations, while recognizing the importance of promoting the development of commerce and industry that utilize sound environmental practices. It is EPD's job to ensure that Longleaf Energy Associates, LLC complies with all applicable air quality rules and regulations. EPD has no input or information about the transportation logistics pertaining to the operation of a coal fired power plant.

As an engineer who has worked in petrochemical manufacturing with BP, and clean fuels technology with Enersol Technologies. I am well aware of the potential damage from lead, mercury, and SO_2, and NOx emissions. I have read the PSD Preliminary Determination and it answers many of the concerns I have. Georgia Power's Plant Bowen is only eight miles from my current home in Adairsville and I do not like the emissions currently coming from this coal fired plant. I know that Georgia Power is in the process of installing new scrubbers at Plant Bowen to control some of the pollution – none to soon. Bartow County is not agriculturally based like Early County so the effects of acid rain may not be as noticeable. I feel that more research need to be done on how these emissions will affect peanut, soybean, cotton, and corn crops in the area.

Response: Please refer to Comment 105 of this Final Determination for more information on this topic.

I have not been able to find any details on how the transportation system will change to accommodate all of the coal trains that will move coal to Longleaf Energy. Rail traffic will increase dramatically. Are there any provisions to install safety devices at some of the prominent rail crossings along the CIRR/CSX routes in Early County?

Response: EPD has no input or information about the transportation logistics pertaining to the operation of a coal fired power plant nor safety devices at rail crossing in Early County.

> Overall, the plant will be a positive move for Early County, though its economic impact will not be as high as residents would like. The projected 125 permanent jobs are needed, but residents also need to be reassured that they are not receiving any higher dosage of pollution than residents living in Atlanta or Athens.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic**.**

Comments from Neil Fleckenstein, Tall Timbers Research Station & Land Conservancy – citizen of Tallahassee, Florida

121. One of the missions of Tall Timbers Research Station & Land conservancy is to protect the unique natural resources of the Red Hills Region of southwest Georgia and north Florida. The Red Hills serves as one of the highest recharge areas for the Floridan Aquifer, the source of drinking water for much of Georgia, Florida, and Alabama. It is also home to numerous outstanding water resources such as the Aucilla and Ochlockonee Rivers and Lakes Iamonia, Miccosukee, and Jackson. Our Tall Timbers Land Conservancy currently has more than 70,000 acres of this landscape protected through conservation easements and has conservation interests throughout southwest Georgia.

    I would like to take this opportunity discuss the 1,200 megawatt pulverized coal power plant proposed by LS Power in Early County, Georgia. Although there have been improvements in technology to reduce the negative environmental consequences of coal power plants, there appears to be considerable uncertainty regarding the specific environmental impacts associated with the proposed plant.

    A number of speakers at the recent public hearing in Blakely, Georgia raised questions regarding whether the proposed facility was in fact using the Best Available Control Technology, citing Integrated Gasification Combined Cycle technology. Another concern expressed by audience members was whether a detailed assessment had been completed to determine possible environmental impacts associated with this plant. We are concerned that emissions from this plant could possibly affect water resources and forest health in southwest Georgia and north Florida.

    I would appreciate a response to the concerns identified above before a final permit is issued for this facility. Thank you for your consideration and I look forward to hearing from you or a member of your staff.

Response: Please refer to Comment 45 of this Final Determination for more information on this topic.

Comments from Doug Wright, Jr. – citizen of Dunwoody, Georgia

122. I am writing this letter to voice my concern for the proposal of the building of a coal-fired power plant in Early County, Georgia. I am a 26 year-old native resident of Dunwoody, Georgia, north of Atlanta. Even in my lifetime, I have seen the growth of a city swallow what used to be pasture farm land and forests. To have a foreign entity propose a project as environmentally taxing as this upsets me. Although this plant may create jobs for Early County locals, the physical effects felt by the particulate matter released by this plant will be hard to ignore. I also find it hard to believe that LS Power will adhere to all of the necessary procedures that will deem the plant environmentally fit. Although I am from the opposite half of the state of Georgia, I am a native who loves his home state. I may not, as one voice, be able to keep this new power plant at bay, but I'd like to know that all tests and environmental requirements are held to firmly. If a new coal-burning plant has to be located in our state, it should have to meet 100% of the EPD standards. Otherwise, New Jersey can keep their plant!

Response: Please refer to Comment 84 of this Final Determination for more information on this topic.

Comments from Ruth A. Carter – citizen of Atlanta, Georgia

123. Do not allow LS Power to build their power plant in Georgia! What outrage we feel this company wants to come to Georgia to build a power plant and contaminate our air and water, when we are already adequately supplied with electricity by Georgia Power, and undoubtedly will not even be using that of LS Power. Why should rights be granted to a "foreign" company to dirty our air purely for their profits, and with no benefits to Georgians?

    How very sad to look at the vistas available in this beautiful state and not be able to see more than a mile, on many days, and know that the mercury contaminated air is harming all of us, particularly women, who unwittingly pass on the mercury contamination in their bodies to their unborn babies. In innocent children, toxic chemicals and particulate matter do astronomically more harm. Thousands of people of all ages are presently dying needlessly each year because of polluted air. Why would you grant a license to an out of state utility to provide electricity to other states, and cause only harm and hardship to our state?

    The water issue between the states is relevant here also, as conflict already exists on usage of Chattahoochee water. What argument can possibly be made for granting a license to LS Power to defile our air and water??

Response: Please refer to Comments 91 and 105 of this Final Determination for more information on this topic.

Comments from Cliff Bush – citizen of Blakely, Georgia

I support the LS Power project in Early County because I trust that a majority of the officials we elect and the committee members they select have the best interest of the citizens of Early County, Georgia on their minds while they have been researching and investigating this project.

We are a community and nation of laws, rules and regulations. If this project meets these criteria I say; draw up the permit. The vast majority of Early County citizens want and need this project. Please permit it now.

Comments from Jerry Humphries – citizen of Albany, Georgia

This new plant will be an economic bonus to the entire region around Early County. It is my belief that the new plant can and will operate in such a way that it will minimize any effects to the environment.

Comments from Todd Bell – citizen of Blakely, Georgia

Do not permit Longleaf Energy LLC. Doing so will add to our pollution + heating of our ozone layer. You will be destroying wetlands and endangered species on this property. Releasing mercury into our air and streams. If these permits go thru, I hope you will be held accountable for your decisions.

Comments from Bob Reid – citizen of Niceville, Florida

124. I'm a 69-year-old 5th-generation Georgia native, re-located by military assignment to Florida some thirty years ago. I grew up not far from the Chattahoochee River, and know it fairly well. I also know the Apalachicola River and Bay system, and its dependence on a steady flow of river water.

Arguments against the proposed coal-fired plant in Early County are many. Among them are the additional fossil CO2 it will add to the world's greenhouse gasses and new mercury released into the aquatic environment. But, more immediately troubling will be the inevitable net loss of river water descending to Apalachicola. The steady increase in water withdrawals from Atlanta to the Florida line have already created a crisis in the health of Apalachicola Bay, --a crisis that this new plant can only worsen.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comments 91 and 105 of this Final Determination for more information on this topic.

With the advent of renewable energy sources, fossil-fueled power plants should be nearing the end of their chapter in world history. Please do whatever you can to help expedite the essential transition to renewables by denying permission to construct this dinosaur.

Response: Please refer to Comments 45 of this Final Determination for more information on this topic.

Comments from Stella Smith – citizen of Early County, Georgia

125. Please do not permit the LS Power plant proposed for Early County. My 5-year-old son is already on 3 prescriptions for breathing and allergy issues. We do not need any more pollution in this county. Our air already ranks very high on the dirtiest counties in Georgia.

The plant would be about 10 miles from our house and the elementary school. There are many children in Early County suffering from asthma that don't have parents with the means or know how to contact you. Please protect those little ones that can't protect themselves!! WE URGE YOU NOT TO PERMIT THIS PLANT.

Response: The Georgia Air Quality Act and the Georgia Rules in 391-3-1-.03(1)(c) state that the permit for the construction or modification of any facility shall be issued upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Therefore, Georgia EPD must issue an air quality permit for the Longleaf facility if they meet all applicable requirements in the rules and regulations that are applicable. Please also refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Allen N. Jelks, Jr. – citizen

I understand that LS Power Company wants to impose on Georgia one more of those massive, pollution-spewing coal-fired power plants that long ago should have been looked upon as the dinosaurs of energy production. LS Power wants to build it in one of the most pristine wildlife areas in the US. Georgians will suffer from the fallout as will Floridians.

Comments from Paulette Moss – citizen of Apalachicola, Florida

126. I just heard there is a plan to put in a coal fired power plant on the Chattahoochee River in Early County Ga. The plant will take in 28 million gallons of water/day and will return 8 million gallons/day – that is a consumptive use of 20 MILLION GALLONS OF WATER/DAY! Now the plant owners say they are not getting the water from the Chattahoochee, but from the Ga Pacific plant close by. Where do you thing Ga Pacific gets their water for their plant. Yes, from the Chattahoochee River. It is estimated that the mercury output from the plant will be about 220 pounds/year.

As the public comment period ends this Thursday-Nov. 16th regarding their plant, I needed to let you know how much this saddens me when I consider the future of our beautiful Apalachicola Bay.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comment 105 of this Final Determination for more information on this topic.

Comments from Doug Alderson – citizen of Tallahassee, Florida

127. I am alarmed at the prospect of another polluting coal plant in the area, this time on the Chattahoochee River (The Longleaf Project). Besides air pollution and associated health risks and global warming problems, I am especially concerned about the massive water removal that would affect the fish and wildlife in the Apalachicola River and associated seafood industry. This plant should be denied or drastically altered.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comment 91 of this Final Determination for more information on this topic.

Comments from Ann Patterson – citizen of Marietta, Georgia

Having a coal-fired power plant anywhere is a bad idea, but it is particularly bad for Georgia. We are trying to move this state forward, not backward. Please do not approve building this plant.

Comments from Mary S. Thieme – citizen of Panama City, Florida

128. I live in Florida, my son lives in Georgia – This power plant could do such damage to our Apalachicola river, the oysters which we all enjoy and our bay that I urge you not to let it happen.

Response: Please refer to Comment 91 of this Final Determination for more information on this topic.

Comments from Harriet Peacock – citizen of Marietta, Georgia

Why can't we just urge and promote conservation, rather than building another big smokestack? Building a coal-fired plant is like buying cigarettes for a teenage to assuage his need for something to do. It will give him something to do all his life, but…

Comments from Laura Wharton – citizen of Crawfordville, Florida

129. Please count me in as one more person who is opposed to the newest coal fueled power plant they are considering in Georgia. It would be a devastating blow to the environment. . . especially for the health of the river and bay affected. Please do what you can to stop this plans for this plant from proceeding. There are much cleaner alternatives that should be employed. Our children and grandchildren will be needing the resources this plant could destroy. Thank you for considering my opinion.

Response: Please refer to Comment 84 of this Final Determination for more information on this topic.

Comments from Richard Harper – citizen of Florida

130. I am a transplant to Florida from the Atlanta area and am sensitive to the multiple uses of the Chattahoochee River. I do not profess to under stand the "power" needs for the area of the proposed plant but I do feel that the additional tons of mercury created each year along with the millions of gallons of water lost from downstream are unacceptable trade-offs for this plant. Please put me down as a NO. This is just not a good idea for the environment, especially for those of us who live downstream and downwind. I appreciate your consideration.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comments 91 and 105 of this Final Determination for more information on this topic.

Comments from Toni Taranto – citizen of Florida

Whatever and however you can put a stop to the idea of building a coal plant (Longleaf), please do so. We do not want anything else to interfere with the beautiful rivers we now have here in the Florida panhandle. The health of everyone is at risk if this plant is built.

Comments from Gathana Parmeanas – citizen of Carrabelle, Florida

131. I wish to express my deep opposition to the proposed coal-fired LS Power Plant in Early County. Its effects will be regional, not just local.

The projected water use would have a devastating effect on the river system downstream, and endanger the shellfish harvest in Apalachicola Bay.

What for Georgia may be a bureaucratic decision involving a permitting procedure is a matter of life and livelihood for those of us dependent on the health of the river.

Please stop the Longleaf Power Plant from being built.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comment 91 of this Final Determination for more information on this topic.

Comments from Richard Bickel – citizen of Apalachicola, Florida

Please, please respect our Apalachicola Bay fishermen and the last great bay of North America. The power plant will kill us.

Comments from Kori Neville – citizen of Cobb County, Georgia

132. Please don't approve the Ls Power proposal for Early County. I know that the EPD can only uphold the current laws and regulations regarding emissions but the public is depending on you and your office to protect the Georgia environment. This facility, as proposed, will not have a positive impact on GA's air, water, or soil. 220 lbs of mercury emitted is TOO MUCH!! Any mercury emitting is too much! Water consumption and the resulting waste will all play a toll on GA and our residents. Please protect GA. Our citizens depend on you.

Response: Please refer to Comment 63 and 77 of this Final Determination for more information on this topic.

Comments from Ellen Ashdown, Ph.D. – citizen of St. Georgia Island, Florida

133. The intelligent, long-term response to the nation's energy crisis – and it is one – is not coal. Especially, it is not a coal plant that will deplete and alter the Chattahoochee River, Apalachicola River, and Apalachicola Bay. My objection is not only as a resident of the Apalachicola area. I worked on coal plant issues several years ago, as part of a marketing team hired by the city of Tallahassee, and have followed the ongoing debate about Tallahassee's participation in a coal plant near Perry, Florida. (The marketing firm, by the way, was hired to argue for the coal plant.) Current coal plants are stop-gap measures that, despite technical improvements, are bad environmental choices. Increasingly scientists are informed citizens know that damage to water ecosystems, even what appears to be minor damage, has profound, multiplying effects: loss of habitat, loss of species, loss of livelihoods, loss of economic viability, and loss of life through all of these as well as pollutants and toxins in water, air, and food.

    This coal plant affects not only Georgians but Floridians and all of the nation's people who eat Apalachicola seafood. I urge you not to approve this plant.

Response: EPD has complied with all requirements associated with this permitting action. The final permit for Longleaf Energy imposes very stringent emissions limits making this facility one of the least emitting coal-fired power plants ever permitted in the United States. In addition, the EPD recently adopted rules requiring significant reductions in sulfur dioxide, nitrogen oxides, particulate matter, and mercury emissions from all existing coal-fired power plants in the entire state. Overall, state-wide, emissions of these pollutants will be decreasing significantly.

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

Comments from Beverly T. McMurray – citizen of Marietta, Georgia

134. I am writing to express my opposition to another coal fueled power plant in Georgia. The resulting pollution concerns me especially because of the wildlife preserve near it. But, the winds would carry that pollution to areas inhabited by people as well, doubling the problem.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Richard Quammen – citizen of Marietta, Georgia

Fortunately, I am able to climb to the top of Kennesaw Mountain, just outside of Marietta in Cobb County, and I am able to do this at least twice each week. From the top I can't help but see the smog.

Normally five times a week I'll commute to work, which takes me down Atlanta Road, between Marietta and Smyrna. Atlanta Road parallels the CSX railroad line. Three times a day, seven days a week, there are trains there, full of coal. I've measured them on my car's odometer at about 1.3 miles long. I think the coal comes from Kentucky. Maybe Montana. But it is going to Plant Scherer, south of Atlanta where three train loads of coal are consumed each day.

No wonder that when I go to Kennesaw Mountain that I can't help but see the smog.

Let's find a better way.

Please do not approve the construction of yet another coal-fired plant.

Comments from Ben Allen – citizen of Georgia

Please do not build any more coal-fired power plants in the state of Georgia. I'm tired of my child coughing uncontrollably every time his asthma acts up. We need clean air and clean energy in Georgia, not old, dirty technology. Thank you.

Comments from Doug Alderson – citizen of Tallahassee, Florida

135. I am very worried about the air pollution that the Longleaf coal power project (LS Power) would create should be it be approved, and the resulting impacts upon human health and global warming. Also, the amount of water that is to be taken from the Chattahoochee River could have negative impacts upon the fish, wildlife and seafood industry associated with the Apalachicola River and Bay. For these reasons, the proposal should be rejected or drastically revised.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comment 91 of this Final Determination for more information on this topic.

Comments from Michael Wall – citizen of Atlanta, Georgia

136. I strongly oppose the permitting of the proposed Longleaf power plant in Early County. I was born in this state (Waycross), I will die in this state, and my entire family lives in this state, predominantly in rural areas where they farm. Everyone know that coal pollution is choking asthmatics and contributing to global warming, so don't allow this construction to go forward. Don't do it. Just tell the power company that their proposed technology is too outdated, and that coal is no longer a fuel the citizens of Georgia prefer. If you permit this plant, you'll be making Georgia (and surrounding states) worse, not better.

    Yes, we need energy, but not the type that causes and exacerbates lung ailments in the short term, and can alter the world's climate in the long term.

    I don't want you guys mucking up Georgia's air with foul pollution from another dog-gone coal-fired power plant.

Response: Longleaf will be employing state of the art technologies. The original technology may have been developed years ago but the advances made make the use of a baghouse, dry scrubber and selective catalytic reduction the best available control technology for a pulverized coal fired power plant. Please also refer to Comment 77 and 84 of this Final Determination for more information on this topic.

Comments from Tom Southern – citizen

Good morning. Please, Please, say no to the proposed coal fired power plant. There are better alternatives, and plenty of people to help you implement them.

Comments from Sue Peters-Ferre – citizen of Navarre, Florida

137. I hope that you will stop this proposed pollution giant from being built as planned. The Chattahoochee River is the lifeline and economic backbone of the Apalachicola River & Bay fishery, and is already threatened by the runaway overdevelopment in the Atlanta metro area. More mega-mansions are being built daily. What a waste of our previous natural resources, all done to stoke the over-inflated egos of those people who think they require 10,000 square feet for 2 people to live in! Just because more people live in the metro area doesn't mean they get to decimate the lifeline of others downstream!!!!!

Rather than spend money on outdated technology of coal fired plants, encourage the development and use of alternative fuels such as solar energy. And above all, encourage the conservation of what electricity is already produced. If that were done on a widespread basis, this new plant wouldn't be necessary in the first plant.

I would appreciate your efforts to stop this unnecessary source of pollution and snatch of water flow on the Chattahoochee and Apalachicola.

Response: Please refer to Comments 45 and 77 of this Final Determination for more information on this topic.

Comments from Mary Lou Smith – citizen of Panama City, Florida

138. I believe it is your job to protect our environment? Then we the people need for you to stop this plant! We should be doing just the opposite to help sustain our blessings from the land and water!

Response: Please refer to Comment 84 of this Final Determination for more information on this topic.

Comments from Becky Hill – citizen of Florida

I am writing to let you know that I am entirely opposed to the proposed coal-powered plant on the Chattahoochee River. I sincerely hope the government of Georgia has more insight and intelligence than to allow the building of such a monster. Please work hard in your department to ensure environmental protection of this great river!

Comments from Praiss Barron – citizen

139. I wanted to express displeasure with the prospect of LS Power being issued a permit to develop the Longleaf plant in Early County. The Chattahoochee River is already over-polluted, and it and the systems which it feeds can ill-afford the additional contaminant. You have already received more informed observations supporting the denial of this proposal than I can succinctly provide in this communication. I can only hope that the comments expressed by myself and others would encourage you to reconsider any decision to permit the Longleaf project to continue. The role of the EPD is to ensure clean air, water, and land and protect and manage the natural resources to meet the needs of current and future generations. If this project is allowed to go forward, then I feel the Department of Natural Resources will have failed all of the EPD's stated goals and the citizens of the state. I would like to thank you in advance for your consideration of this matter.

Response: Please refer to Comment 77 and 84 of this Final Determination for more information on this topic.

Comments from Rhonda Coleman – citizen of Early County, Georgia

140. As a resident of Early County, I am deeply concerned about the plan to put in a new coal fired power plant on the Chattahoochee River in Early County, GA. I understand that we are one of the poorest counties in the state and that the plant will provide jobs and tax income for the county. But I also understand that agriculture/forestry is the leading industry in the county and that scientific studies have shown that a coal fired plant negatively affects the growth of pine trees and peanuts. Our farmers struggle to stay afloat as it is, they certainly don't need another obstacle to overcome. We should not have to trade the success of our agriculture/forestry industry for a few jobs at the LS Power Plant.

Response: Please refer to Comment 105 of this Final Determination for more information on this topic.

Pollution is another negative aspect of the plant. Smog, mercury, global warming are all effects of the energy that comes from coal-fired power plants. The paper mill that is now located in the county is a tremendous polluter and we don't need to add to their pollution. We live in a "garden spot" of the state but that will not be true for long if we add to the pollution.

And, of course, pollution causes many health problems. Health problems that affect not only the individual but our economy, too.

We definitely need an economic boost in our area, but the cost is just too high.

Please reconsider the idea of awarding a permit for this coal-fired electric plant. We can't afford it!!

Response: Please refer to Comment 77 of this Final Determination for more information on this topic

Comments from Brandon L. Bowen – citizen of Cartersville, Georgia

141. I wish to take this opportunity to voice an objection to the Longleaf power plant under consideration for citing in Early County, Georgia. While I am not from Early County, my wide was born and raised from there, and her family remains in Blakely, and so I am well familiar with the County and its beautiful and wholesome environment. My wife and I actually live in Bartow County, Georgia, close to Georgia Power's Plant Bowen, and I am very disappointed that people still wish to install new coal-fired power plants. While it is indisputable that our society requires a substantial amount of energy, which must be generated somewhere and somehow, I believe that it is the role of the Georgia EPD to steer Georgia in the direction of newer, better, and cleaner technology. It is my understanding that this proposed plant is not even using cogeneration, which at least reduces the environmental consequences of generating electricity from coal. I am very concerned that when I take my young son to visit his grandparents in Early County, he will no longer be escaping the effects of coal-fired power plants. I hope that when the EPD rules on this plant, if the decision is made to allow a power plant at all, it will at least require Longleaf to use the most advanced technology available.

Response: Please refer to Comments 84 of this Final Determination for more information on this topic.

Comments from Charles J. Moulton – citizen of Early County, Georgia

142. I am a native of Early County, Georgia. My friends and family still live in the area and have for generations. I fully understand the crushing effects of poverty in the region. I know all too well that Early County is desperate for economic development, but I do not believe that the building of coal-burning power plant is in the best interests of the citizens of Early County and the surrounding areas.

Coal-burning power plants have a devastating environmental impact. There have been advancements in technology, but the fact remains that this is dirty industry. This plant poses a serious threat to the health of region's citizens and to the environment. The potential economic gains simply do not outweigh all of the risks. I urge the State of Georgia to prohibit the construction of the coal-burning power plant in Early County.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Comments from Geoffrey Hewell – citizen of Apalachicola, Florida

Please vote NO for more pollution entering the Apalachicola river, NO power plant in EARLY CO GA. I am a resident of Apalachicola, Florida. Please help us.

Comments from Ben Fusaro – citizen of Florida

143. It is puzzling how it is worthwhile to trade-off a pristine wildlife area, reduction of Chattahoochee flow, and Hg, NOx, Sox (and the rest of the power plant pollution) for jobs. If it were an advanced 1200 MW plant, that might be different, but for a Pulverized Coal, power plant, a refugee from some Museum of Ancient Technology . . .?

    Please take a fresh look at your original, and high-minded DNR changes and re-evaluate this trade-off. It could be a cause of trading off a natural birthright for a mess of rustbelt-in-the-making industry.

Response: Please refer to Comments 84 of this Final Determination for more information on this topic.

Comments from Drew Martin – citizen of Lake Worth, Florida

144. I oppose the coal fired plant on the Chattahoochee River in Early County Ga. The plant will take in 28 million gallons of water/day and will return 8 million gallons/day – that is a consumptive use of 20 MILLION GALLONS OF WATER/DAY! This is a loss of 20 million gallons/day of flow into the Apalachicola River to this power plant. Of course, we are already losing water we are losing upstream already.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users.

Comments from Elisabeth Green – citizen of Panama City, Florida

145. As an Atlanta native and now Florida Panhandle resident, I have been and continue to be very concerned about the health of the Chattahoochee River. I urge you to please stridently oppose the construction of this coal powered plant. The Apalachicola River and the bay it feeds is a pristine and unique resource that we could all strive to guard the health of. The runoff from this plant will cause significant harm to the marine life and the human life that depend upon it for their livelihood, not to mention the significant impact on the tourism industry should this fragile ecosystem be harmed.

Response: Please refer to Comments 91 and 105 of this Final Determination for more information on this topic.

Comments from Arthur Gay – Citizen of Tallahassee, Florida

146. I would hope this facility can be stopped because of the damage to the environment and to the river system as well. There is already a major amount of damage being done to the flow of the Chattahoochee system and this will complicate it further. Consider that the seafood industry is fragile and depends upon protecting the amount of mercury into the water that supports the seafood … and lessens the amount of fresh water available tremendously.

Response: EPD has taken into consideration all relevant factors required by our state laws and rules in making a decision regarding issuance of the water withdrawal and NPDES permits. EPD does not expect that the loss of water from the Chattahoochee River would cause adverse impacts on downstream users. Also, please refer to Comments 91 and 105 of this Final Determination for more information on this topic.

Comments from AT Macmillian – citizen

147. I write to express my dismay at the thought that there is the slightest possibility of a coal plant being permitted using water from our precious Chattahoochee River watershed. The thought of al that mercury being released back into the watershed, never mind the other pollution the coal is proven to spew everywhere, terrifies me. I am a frequent visitor to Apalachicola, Florida, her River, and her Bay, and building such an unwelcome source of pollution and fresh water deprivation upstream of Apalachicola's already-threatened seafood-producing waters would be a disaster. Please so what you can to permanently erase the idea that such a plant could be built upstream of Apalachicola.

Response: Please refer to Comments 91 and 105 of this Final Determination for more information on this topic.

Comments from Kathleen Baha-dirli – citizen

Please help us protect our environment by stopping the construction of this power plant. Our environment, our rivers and our wildlife need protection. You have the power to make a difference.

We must be responsible for the future of our environment. We must protect our rivers, gulf wildlife from pollution and ultimate destruction.

Comments from Lesley Cox – citizen of Carrabelle, Florida

148. I live in Franklin County, Florida near the Apalachicola River and Bay. I have been involved with preserving and protecting our natural resources here in Northwest Florida for nearly thirty years. I cherish our abundant seafood and depend on the Apalachicola River to provide the bay with plenty of clean fresh water for the survival of the estuary. I do not want another coal fired power plant that will take water from an already over consumed river and rain down mercury on me and the fish I eat.

    In this day and age, after all the studies of bio-accumulation in the food chain, I find it intolerable that you are even considering a permit to foul a major food source, the Apalachicola Bay and the Gulf of Mexico. Perhaps you should come to Franklin County and enjoy some of the world's finest fish and shellfish before you make a decision that could affect the health and livelihood of so many people.

Response: Please refer to Comments 91 and 105 of this Final Determination for more information on this topic.

Comments from Jim Loyed – citizen of Florida

As a native of Early County and a current resident of the panhandle I too oppose this plant. I hate it for Early County but these river systems that flow through Southwest Georgia and Southeast Alabama have got to quit polluting our waters. The bays and inland waters of the panhandle are fragile and once destroyed will never be repaired. I know they need the industry but I hate to see what we all have to pay for it.

Comments from Karen Parsons – citizen of Florida

HERE'S MY VOTE FOR THE NEW COAL PLANT IN EARLY COUNTY, GA.

NO – NO – NO – NO
I've lived in North Florida all my life and love seafood.

Please don't allow them to destroy this wonderful estuary that produces our seafood by pumping mercury into our rivers and extracting precious waters which could affect water levels.

Please don't let this happen.

Mass Email Comments via Ask EPD Website

149. Please do not issue an air pollution permit for a new coal-fired power plant, proposed by LS Power, in Early County, Georgia. I am concerned about air pollution and mercury contamination which are already problems linked to coal plants in Georgia. Instead we should build a more secure, clean, and economically beneficial energy future by supporting energy efficiency and renewable energy.

Response: Please refer to Comment 84 and 92 of this Final Determination for more information on this topic.

Form letter submitted by local citizens

150. I am opposed to the proposed LS Power Coal-Fired Power Plant in Early County, Georgia. Damaging the environment by burning coal is unacceptable to me.

I am very concerned about the toxic chemicals that will be produced during the operation of the coal plant and how the toxic emissions will damage my health and the health of those who live in a widespread area surrounding the plant.

The Chattahoochee River and the clean environment in Early County are our greatest assets and present the greatest opportunity for economic development in the county.

I respectfully as the EPD to refuse to permit the LS Power Coal-Fired Power Plant in Early County, Georgia.

Response: Please refer to Comment 77 of this Final Determination for more information on this topic.

Additions and Changes to the Draft Permit

NOTE B

FACIILTY DESCRIPTION

Emission Units		Air Pollution Control Devices	
ID No.	Description	ID No.	Description
Combustion Sources			
S01	PC-Fired Boiler – 600 MW	LN1 CR1 DS1 F01	Low NOx Burners/Over-fire Air Selective Catalytic Reduction Dry Scrubber Fabric Filter Baghouse
S02	PC-Fired Boiler – 600 MW	~~LN1~~ **LN2** ~~CR1~~ **CR2** ~~DS1~~ **DS2** ~~F01~~ **F02**	Low NOx Burners/Over-fire Air Selective Catalytic Reduction Dry Scrubber Fabric Filter Baghouse
S03	Auxiliary Boiler – 175 MMBtu/hr	LN3	Low NOx Burner/Flue Gas Recirculation
Coal Handling Particulate Sources			
S06	Railcar Unloading Station	N/A	Water sprays and partial enclosure
S07	Stackout Conveyor # 1	N/A	Partial enclosure
S08	Stackout Transfer Point #1	N/A	Partial enclosure
S09	Stackout Conveyor #2	N/A	Partial enclosure
S10	Stackout Transfer Point #2	N/A	Telescopic chute
S11	Active Pile #1	N/A	Water Sprays
S12	Active Pile #2	N/A	Water Sprays
S13	Active Pile Reclaim	N/A	Partial enclosure
S14	Reclaim Conveyor #1	N/A	Partial enclosure

Emission Units		Air Pollution Control Devices	
ID No.	Description	ID No.	Description
S15	Transfer Tower	N/A	Partial enclosure and fabric filter
S16	Reclaim Conveyor #2	N/A	Partial enclosure
S17	Tripper Deck	N/A	Partial enclosure and fabric filter
S18	Inactive Pile	N/A	Water spray and chemical dust suppression
Ash Management Particulate Sources			
S19	Submerged Chain Conveyors	N/A	Partial enclosure and material moisture content
S20	Bottom Ash Transfer Point #1	N/A	Material moisture content
S21	Bottom Ash Conveyor	N/A	Partial enclosure and material moisture content
S22	Bottom Ash Bunker	N/A	Partial enclosure and material moisture content
S23	Bottom Ash Transfer Point #2	N/A	Material moisture content
S24	Bottom Ash Truck	N/A	Material moisture content
S25	Bottom Ash Transfer Point #3	N/A	Material moisture content
S26	Fly Ash Silo	N/A	Fabric Filter
S27	Fly Ash Mixing Station	N/A	Fabric Filter
S28	Fly Ash Transfer Point #1	N/A	Material moisture content
S29	Fly Ash Truck	N/A	Material moisture content
S30	Fly Ash Transfer Point #2	N/A	Material moisture content
S31	On-Site Disposal Facility	N/A	Water sprays and chemical suppressant
Lime Management Particulate Sources			

Emission Units		Air Pollution Control Devices	
ID No.	Description	ID No.	Description
S35	Lime Railcar Unloading Station	N/A	Partial enclosure and fabric filter
S36	Lime Conveyor	N/A	Partial enclosure
S37	Lime Silo	N/A	Partial enclosure and fabric filter
Roadway Particulate Sources			
S38	Unpaved Roadway Travel	N/A	Gravel or chemical dust suppressant and water sprays
S39	Paved Roadway Travel	N/A	Water sprays and/or sweeping
Cooling Tower Emissions			
S40	Unit 1 Cooling Tower	N/A	Drift eliminators
S41	Unit 2 Cooling Tower	N/A	Drift eliminators
Emergency Diesel Fired Engines			
S42	1500 kW Diesel Generator	N/A	N/A
S43	450 hp Diesel Firewater Pump	N/A	N/A
Fuel Storage Tanks			
S44	330,000 Gallon Distillate Oil Storage Tank	N/A	N/A
S45	15,000 Gallon Distillate Fuel Storage Tank	N/A	N/A
S46	2,000 Gallon Diesel Fuel Storage Tank	N/A	N/A
S47	500 Gallon Diesel Fuel Storage Tank	N/A	N/A
S48	150 Gallon Unleaded Gasoline Storage Tank	N/A	N/A

1.5 The Permittee shall comply with all applicable provisions of National Emission Standard for Hazardous Air Pollutants (NESHAP) 40 CFR 61, Subpart E – "National Emission Standard for Mercury" **when PC-Fired Boilers, S01 and S02, when firing clarifier sludge.** [40 CFR 61.50]

1.9 Permittee shall comply with all applicable provisions of the New Source Performance Standard (NSPS) as found in 40 CFR Part 60, in Subpart Da – "Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978**" for PC-Fired Boilers, S01 and S02**.
[40 CFR 60, Subpart Da]

1.10 Permittee shall comply with all applicable provisions of the New Source Performance Standard (NSPS) as found in 40 CFR Part 60, in Subpart Db – "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" **for the auxiliary boiler, S03**.
[40 CFR 60, Subpart Db]

1.11 The Permittee shall comply with all applicable provisions of the New Source Performance Standard (NSPS) as found in 40 CFR Part 60, in Subpart Y – "Standards of Performance for Coal Preparation Plants" **for the coal conveying and processing equipment and the coal silos**.
[40 CFR 60, Subpart Y]

2.9 The Permittee shall install and operate, as BACT for Fly Ash Silo, S26, and Lime Silo, S37, enclosures and ~~fabric filters~~ **vent filters**.
[40 CFR 52.21(j)]

2.10 Except as provided in Condition No. 2.12 the Permittee shall primarily fire PRB Coal, CAPP Coal, and/or clarifier sludge in PC-Fired Boiler, S01 and S02. Blending of other sources of bituminous coal and/or pet coke shall be permitted subject to Conditions 2.11 ~~and~~ 2.14 **and 2.15**.
[40 CFR 52.21(j); and 391-3-1-.02(2)(g)(subsumed)]

2.13 ~~Ultra low sulfur fuel oil~~ **Ultra low sulfur diesel (ULSD) fuel oil** fired in startup in PC-Boiler, S01 and S02, in auxiliary boiler S03, emergency generator S42 and firewater pump S43 shall not contain more than 0.0015 percent sulfur by weight [which is equivalent to 15 ppm as defined in 40 CFR 80.520-527]. [40 CFR 52.21(j); 391-3-1-.02(2)(g) (subsumed)]

2.14 The Permittee shall not fire clarifier sludge in PC-Fired Boilers, S01 and S02, that contains greater than 1.0 percent of the potential total heat input or 61.4 MMBtu/hr in any calendar day.

2.15 The Permittee shall not discharge, or cause the discharge, into the atmosphere, from each PC-Fired Boiler, S01 and S02, any gases which

a. Contain nitrogen oxides (NOx) in excess of 0.07 lb/MMBtu on a 30-day rolling average.
[40 CFR 52.21(j); ~~40 CFR 60.44a(e)(1)~~ **40 CFR 60.44Da(e)(1)** (subsumed)]

b. Contain nitrogen oxides (NOx) in excess of 0.05 lb/MMBtu on a 12-month rolling average. This condition becomes effective 6 months after initial start-up of each PC-Fired boiler, S01 and S02, absent approval by the Division for an extension of this date.
[40 CFR 52.21(j); 40 CFR 60.44Da(e)(1) (subsumed)]

~~b~~ **c**. Contain carbon monoxide (CO) in excess of 0.15 lb/MMBtu on a 30-day rolling average and 0.30 lb/MMBtu on a 1-hour average.
[40 CFR 52.21(j)]

~~c~~ **d**. Contain particulate matter (PM) in excess of 0.012 lb/MMBtu for filterable particulate matter (PM) **on a 3-hour average** and 0.030 lb/MMBtu for total particulate matter.
[40 CFR 52.21(j); 391-3-1-.02(2)(d) (subsumed); 40 CFR 60.42Da(c) (subsumed)]

~~d~~ **e**. Contain sulfur dioxide in excess of 0.065 lb/MMBtu on a 30-day rolling average when the uncontrolled sulfur dioxide emission rate is less than or equal to 1 lb/MMBtu on a 30-day rolling average.
[40 CFR 52.21(j); ~~40 CFR 60.43a(i)~~ **40 CFR 60.43Da(i)(l)(i)** (subsumed); 391-3-1-.02(2)(d) (subsumed)]

~~e~~ **f**. Contain sulfur dioxide in excess of 0.08 lb/MMBtu on a 30-day rolling average when the uncontrolled sulfur dioxide emission rate is greater than 1 lb/MMBtu but less than 1.25 lb/MMBtu on a 30-day rolling average.
[40 CFR 52.21(j); ~~40 CFR 60.43a(i)~~ **40 CFR 60.43Da(i)(l)(i)** (subsumed); 391-3-1-.02(2)(d) (subsumed)]

~~f~~ **g**. Contain sulfur dioxide in excess of 0.105 lb/MMBtu on a 30-day rolling average when the uncontrolled sulfur dioxide emission rate is greater than 1.25 lb/MMBtu but less than 1.6 lb/MMBtu on a 30-day rolling average.
[40 CFR 52.21(j); ~~40 CFR 60.43a(i)~~ **40 CFR 60.43Da(i)(l)(i)** (subsumed); 391-3-1-.02(2)(d) (subsumed)]

~~g~~ **h**. Contain sulfur dioxide in excess of 0.12 lb/MMBtu on a 24-hour average.
[40 CFR 52.21(j); 40 CFR 60.43Da(i)(l)(i) (subsumed); 391-3-1-.02(2)(d) (subsumed)]

~~h~~ **i**. Contain volatile organic compounds (VOC) in excess of 3.6 x 10^{-3} lb/MMBtu, as methane, on a 3-hour average.
[40 CFR 52.21(j)]

~~i~~ **j**. Contain lead (Pb) in excess of 1.8 x 10^{-5} lb/MMBtu on a 3-hour average.
[40 CFR 52.21(j)]

~~j~~ **k**. Contain ~~fluorine~~ **fluorides** (as HF) in excess of 9.5 x 10^{-4} lb/MMBtu on a 3-hour average while firing PRB coal or 1.4 x 10^{-3} lb/MMBtu on a 3-hour average while firing CAPP Coal.
[40 CFR 52.21(j)]

~~k~~ **l**. Contain sulfuric acid mist (H_2SO_4) in excess of 0.005 lb/MMBtu on a 3-hour average.
[40 CFR 52.21(j)]

~~l~~ **m**. Contain mercury (Hg) in excess of 15 x 10^{-6} lb/MW-hr on an annual average while firing PRB coal or 6 x 10^{-6} lb/MW-hr on an annual average while firing CAPP coal, or a computed weighted average based on the proportion of energy output ~~in BTU~~ **gross MW output** contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit.
[40 CFR 52.21(j); 40 CFR 60.45Da(a) (subsumed)]

~~m~~**n**. Contain mercury from clarifier sludge incineration in **both** PC-Fired Boilers, S01 and S02, in excess of 3.2 kg (7.1 lb) of mercury per 24-hour period.
[40 CFR 61.52(b)]

~~n~~ **o**. Contain hydrochloric acid (HCl) in excess of 0.0013 lb/MMBtu on a 3-hour average while firing PRB coal or 0.0083 lb/MMBtu on a 3-hour average while firing CAPP coal.
[Georgia Air Toxic Guideline - 391-3-1-.02(2)(a)3]

~~o~~ **p**. Exhibit greater than 20 percent opacity.
[40 CFR 52.21(j); and 391-3-1-.02(2)(d) (subsumed); 40 CFR 60.42Da(b) (subsumed)]

2.17 The Permittee shall limit each PC-Fired boiler, S01 and S02, to a maximum design heat input of 6,139 MMBtu/hr.
[40 CFR 52.21(j)]

2.24 The Permittee shall install and operate, as BACT for cooling towers, S40 and S41, drift eliminators and shall maintain documentation that a 0.001% drift is guaranteed.
[40 CFR 52.21(j)]

4.1 Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**. The methods for the determination of compliance with emission limits listed under Section 2.0 which pertain to the emission units listed in Note B are as follows:

a. Method 1 shall be used for the determination of sample point locations,

b. Method 2 shall be used for the determination of stack gas flow rate,

c. Method 3 or 3A shall be used for the determination of stack gas molecular weight,

d. Method 3B shall be used for the determination of the emissions rate correction factor or excess air, Method 3A may be used as an alternative;

e. Method 4 shall be used for the determination of stack gas moisture,

f. Method 5 or Method 17, as applicable, for the determination of filterable Particulate Matter concentration, the sampling time for each run shall be two hours,

~~g. Method 6 or 6C for the determination of Sulfur Dioxide concentration, the sampling time for each run shall be one hour,~~

~~h~~ **g.** Method 7 or 7E for the determination of Nitrogen Oxide concentration from the auxiliary boiler, S03, the sampling time for each run shall be one hour,

~~i~~. **h**. Method 8 shall be used for the determination of sulfur acid mist emissions, the sampling time for each run shall be one hour,

~~j~~ **i**. Method 9 and the procedures contained in Section 1.3 of the above reference document shall be used for the determination of opacity,

~~k~~ **j**. Method 10 shall be used for the determination of carbon monoxide concentration, the sampling time for each run shall be one hour,

~~l~~ **k**. Method 19 shall be used for the determination of particulate matter (PM), carbon monoxide, and nitrogen oxides, and sulfur dioxide emission rates,

~~m.~~ **l**. Method 25A shall be used to determine total Hydrocarbons and to calculate Volatile Organic Compound emissions, the sampling time for each run shall be one hour,

~~n~~ **m** Method 26A shall be used for the determination of Fluorine and hydrochloric acid emission rates, the sampling time for each run shall be one hour,

~~o~~ **n**. Method 29 shall be used for the determination of lead emission rates, while firing PRB or CAPP coal, the sampling time for each run shall be one hour,

~~p~~ **o.** Method 101A for a stack test or 105 for sludge sampling shall be used for the determination of mercury emissions while firing clarifier sludge unless an alternative method is approved by EPA,

~~q~~ **p.** Method 202 shall be used for the determination of the condensible portion of total particulate matter.

~~r~~ **q.** Compliance with the Hg limit in Condition 2.15.m. shall be determined according to the procedures in 40 CFR 60.50a(h)(1) through (h)(3) **using the CEMS required by Condition 5.2.**
[40 CFR 52.21; 391-3-1-.02(6)(b)1; 40 CFR 60.13]

r. Compliance with the NOx limit in Condition 2.15.a**. and 2.15.b.** and the SO_2 limits in Condition 2.15.e., 2.15.f., 2.15.g., and 2.15.h. shall be determined using the CEMS required by Condition 5.2.
[40 CFR 52.21; 391-3-1-.02(6)(b)1; 40 CFR 60.13]

s. Compliance with the CO limit in Condition 2.15.c. shall be determined using the CEMS required by Condition 5.2.
[40 CFR 52.21; 391-3-1-.02(6)(b)1; 40 CFR 60.13]

t. Compliance with the filterable PM limit in Condition 2.15.d. shall be determined using the CEMS required by Condition 5.2.
[40 CFR 52.21; 391-3-1-.02(6)(b)1; 40 CFR 60.13]

~~t~~ **u.** Compliance with the opacity limit in Condition 2.15.p. shall be determined using the COMS required by Condition 5.2.

Minor changes in methodology may be specified or approved by the Director or his/her designee when necessitated by process variables, changes in facility design, or improvement or corrections, which, in his opinion, render those methods or procedures, or portions thereof, more reliable.
[391-3-1-.02(3)(a)]

4.2 Within 60 days after achieving the maximum production rate on each coal type (PRB and CAPP) at which each PC-fired boiler, S01 and S02, will be operated, but not later than 180 days after the initial startup of each boiler for each coal type, the Permittee shall conduct the following performance tests and furnish to the Division a written report of the results of such performance tests:

a. Performance tests on each PC-fired boiler, S01 and S02, for volatile organic compounds at base load and at 50 percent load to verify compliance with Condition No. 2.14.h.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]

b. Performance tests on each PC-fired boiler, S01 and S02, for particulate emissions (PM) to verify compliance with Condition No. 2.14.c.
[40 CFR 52.21, 40 CFR 60.13, 40 CFR 60.42a(c) (subsumed), 391-3-1-.02(6)(b)1.(i)]

c. Performance tests on each PC-fired boiler, S01 and S02, for lead to verify compliance with Condition No. 2.14.i.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]

d. Performance tests on each PC-fired boiler, S01 and S02, for fluoride emissions (as HF) while firing PRB coal to verify compliance with Condition No. 2.14.j.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]

e. Performance tests on each PC-fired boiler, S01 and S02, for fluoride emissions (as HF) while firing CAPP coal to verify compliance with Condition No. 2.14.j.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]

f. Performance tests on each PC-fired boiler, S01 and S02, for sulfuric acid mist to verify compliance with Condition No. 2.14.k.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]

g. Performance tests on each PC-fired boiler, S01 and S02, for hydrochloric acid while firing PRB coal to verify compliance with Condition No. 2.14.n.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]

h. Performance tests on each PC-fired boiler, S01 and S02, for hydrochloric acid while firing CAPP coal to verify compliance with Condition No. 2.14.n.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]

~~i. Performance tests on each PC-fired boiler, S01 and S02, for mercury while firing PRB coal to verify compliance with Condition No. 2.14.l.~~
~~[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]~~

~~j. Performance tests on each PC-fired boiler, S01 and S02, for mercury while firing CAPP coal to verify compliance with Condition No. 2.14.l.~~
~~[40 CFR 52.21 and 391-3-1-.02(6)(b)1.(i)]~~

k. Performance test or sludge sampling on each PC-Fired Boilers, S01 and S02, shall be completed within 90 days of start up for mercury while firing clarifier sludge to very compliance with Condition No. 2.14.m, unless an alternative is approved by EPA. If the facilities emissions exceed 1.6 kg (3.5 lb) per 24-hour period, demonstrated either by stack sampling according to §61.53 or sludge sampling according to §61.54 or another alternative approved by EPA, shall monitor mercury emissions at intervals of at least once per year by use of Method 105, or an alternative approved by EPA.

5.2 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated pollutants on the following equipment. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.

a. A Continuous Emissions Monitoring System (CEMS) for measuring NOx emissions discharged to the atmosphere from each PC-fired boiler stack, S01 and S02. The one-hour average nitrogen oxides emissions rates shall also be recorded in pound per million Btu heat input [40 CFR 52.21; 391-3-1-.02(6)(b)1; 40 CFR 60.13]

b. A Continuous Emissions Monitoring System (CEMS) for measuring carbon monoxide emissions discharged to the atmosphere from each PC-fired boiler stack, S01 and S02. The one-hour average carbon monoxide emissions rates shall also be recorded in pound per million Btu heat input. [40 CFR 52.21and 391-3-1-.02(6)(b)1]

c. A Continuous Emissions Monitoring System (CEMS) for measuring SO_2 emissions at both the inlet and outlet of the SO_2 control device. The one-hour average sulfur dioxides emissions rates shall be recorded in pound per million Btu heat input [40 CFR 52.21; 391-3-1-.02(6)(b)1; 40 CFR 60.13]

d. A Continuous Emissions Monitoring Systems (CEMS) to measure and record the concentration of Hg in the exhaust gases from each PC-fired boiler stack according to the requirements in 40 CFR 60.49a(p)(1) through (p)(3). Alternatively, for an affected facility that is also subject to the requirements of 40 CFR 75 Subpart I, the Permittee may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to 40 CFR 75.10 and appendices A and B to 40 CFR 75, in lieu of following the procedures in 40 CFR 60.49a(p)(1) through (p)(3). [40 CFR 52.21; 391-3-1-.02(6)(b)1; 40 CFR 60.13]

e. A Continuous Opacity Monitoring System (COMS) on each PC-fired Boiler stack, S01 and S02.

f. A Continuous Emissions Monitoring System (CEMS) for measuring filterable particulate matter emissions discharged to the atmosphere from each PC-fired boiler stack, S01 and S02. The system shall meet the requirements in 40 CFR 60.48a(p)(2) through (p)(8).

g. A continuous monitoring system for measuring oxygen or carbon dioxide at each location where ~~SO_2 or NOx emissions are monitored~~ **SO_2, PM, CO or NOx emission monitors are required.**

5.3 The Permittee shall install, calibrate, maintain, and operate monitoring devices for the measurement of the indicated parameters on the following equipment. Data shall be recorded at the frequency specified below. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.

a. The cumulative total hours of operation, during all periods of operation, for each of the following: auxiliary boiler S03, emergency generator S42, and firewater pump S43. Data shall be recorded monthly.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21].

b. The amount of clarifier sludge (in pounds) combusted in each PC-Fired Boiler, S01 and S02. The data will be recorded once per calendar day of process operation.

c. The heat input to each PC-Fired Boiler, S01 and S02. Data shall be recorded hourly using heat input determined in accordance with 40 CFR 75.

8.3 The Permittee shall obtain a sample ~~of each coal train~~ **from each coal shipment** for analysis for sulfur content (%S), moisture content, ash content, and Gross Caloric Value (GCV). The sample shall be acquired and analyzed using the procedures of Section 12.5.2.1 in Method 19 of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**.
[391-3-1-.02(6)(b)1(i)]

8.4 The Permittee shall retain records of all fuel burned in the PC-Fired boilers, S01 and S02 at the frequency specified below. The records shall be available for inspection or submittal to the Division, upon request, and contain the following:
[391-3-1-.02(6)(b)1(i)]

a. ~~Monthly quantity (tons) of coal burned.~~ **Monthly quantity (tons) of each coal type burned.**

b. Monthly quantity (gallons) of ultra low sulfur diesel fuel oil burned.

c. Quantity (pounds) of clarifier sludge burned daily (24-hour).

d. Monthly quantity (tons) of pet coke burned.

8.6 For each shipment of ~~ultra low sulfur diesel~~ **ULSD** fuel oil received, the Permittee shall obtain from the supplier of the fuel oil, a statement certifying that the oil complies with the specifications of ultra low sulfur diesel fuel oil contained in ASTM D 975. As an alternative to the procedure described above, the Permittee may, for each shipment of ultra low sulfur diesel fuel oil received, obtain a sample for analysis of the sulfur content. The procedures of ASTM D 4057 shall be used to acquire the sample. Sulfur content shall be determined using the procedures of Test Method ASTM D 129 or by some other test method approved by the US EPA and acceptable to the Division.
[40 CFR 63.7506 and 391-3-1-.02(6)(b)1(i)]

8.8 The Permittee shall determine compliance with the NOx emissions limitations in Condition No. 2.14.a and b using emissions data acquired by the NOx CEMS. The 30-day rolling average and 12-month rolling average shall be determined as follows: [391-3-1-.02(6)(b)1(i)]

a. The 30-day average shall be the average of all valid hours of NOx emissions data for any 30 successive operating days.

b. After the first 30-day average, a new 30-day rolling average shall be calculated after each operating day.

c. A twelve consecutive month total shall be the total for a month in the reporting period plus the totals for the previous 11 consecutive months. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.

~~c~~ **d**. For the purpose of this Permit, an operating day is a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period.

8.10 The Permittee shall ~~assure~~ **determine** compliance with the CO emissions limitations in Condition No. 2.14.b using emissions data acquired by the CO CEMS. The 30-day rolling average shall be determined as follows: [391-3-1-.02(6)(b)1(i)]

a. The 30-day average shall be the average of all valid hours of CO emissions data for any 30 successive operating days.

b. After the first 30-day average, a new 30-day rolling average shall be calculated after each operating day.

c. For the purpose of this Permit, an operating day is a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period

8.11 The Permittee shall determine compliance with the PM filterable emissions limitations in Condition No. 2.14.c using emissions data acquired by the PM CEMS. The 3-hour rolling average shall be determined as follows: [391-3-1-.02(6)(b)1(i)]

a. The 3-hour average shall be the average of all valid hours of PM filterable emissions data for any 3 successive operating hours.

b. After the first 3-hour average, a new 3-hour average shall be calculated after each 3-hour block.

~~8.11 The Permittee shall determine and record the emission rate (lb/MW-hr) of mercury from each PC-Fired Boiler while firing coal. The emission rate from each stack, as specified in Condition No. 2.14, shall be recorded continuously.~~
~~[40 CFR 52.21; 391-3-1-.02(6)(b)1.(i)]~~

8.12 The Permittee shall determine compliance with the mercury emissions limitations in Condition No. 2.15.l using emissions data acquired by the mercury CEMS. The annual average shall be determined as follows: [40 CFR 52.21; 391-3-1-.02(6)(b)1.(i)]

a. The Permittee shall determine and record the emission rate (lb/MW-hr) of mercury from each PC-Fired Boiler while firing coal. The emission rate from each stack, as specified in Condition No. 2.14, shall be recorded continuously.

b. **Using the above records the Permitte shall determine the monthly emission rate, in lb/MW-hr per month, of mercury from each PC-Fired Boiler. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.**

c. A twelve consecutive month total shall be the total for a month in the reporting period plus the totals for the previous 11 consecutive months. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.

~~8.13 The Permittee shall use the records required by Condition No. 8.11 to determine the monthly emission rate, in lb/MW-hr per month, of mercury from each PC-Fired Boiler. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.~~
~~[391-3-1-.02(6)(b)1. and 40 CFR 52.21]~~

~~8.14 The Permittee shall use the records required by Condition No. 8.13 to determine the twelve consecutive month total of mercury emissions (in lb/MW-hr) from each PC-Fired Boiler, for each month. A twelve consecutive month total shall be the total for a month in the reporting period plus the totals for the previous 11 consecutive months. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.~~
~~[391-3-1-.02(6)(b)1. and 40 CFR 52.21]~~

8.15 The Permittee shall use the records required by Condition No. 8.12 to determine the 24-hour total of mercury emissions (in lbs) from each PC-Fired Boiler, for each month **while firing clarifier sludge**. For the purpose of this Permit, an operating day is a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period.
[40 CFR 61.55]

8.16 The Permittee shall verify and document that each shipment of ultra low sulfur diesel fuel oil **(ULSD)** received for combustion in the auxiliary boiler, emergency diesel generator, and the firewater pump, S03, S42, and S43, complies with the requirements of Condition 2.12 of the Permit by either of the following means:
[40 CFR 63.7506 and 391-3-1-.02(6)(b)1(i)]

a. Fuel oil receipts obtained from the fuel supplier certifying that the oil is diesel fuel oil and contains less than or equal to 0.0015 percent sulfur, by weight.

b. Analysis of the fuel oil conducted by methods of sampling and analysis which have been specified or approved by the Division which demonstrates that the diesel fuel oil contains less than or equal to 0.0015 percent sulfur, by weight.

8.19 The Permittee shall determine and record the heat rate from each PC-Fired Boiler, S01 and S02 to ensure that each boiler operates under the maximum design heat input rate as stated in Condition No. 2.17.
[391-3-1-.02(6)(b)1(i) and 40 CFR 52.21]

8.20 The Permittee shall maintain documentation that the drift eliminators from each cooling tower, S40 and S41 operate in a manner that is consistent with Condition No. 2.24.
[391-3-1-.02(6)(b)1(i) and 40 CFR 52.21]

~~8.24~~**8.25** For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition No. 8.24, the following excess emissions, exceedances, and excursions shall be reported:
[40 CFR 52.21 and 391-3-1-.02(6)(b)1]

a. Excess emissions: (means for the purpose of this Condition and Condition No. 8.24, any condition that is detected by monitoring or record keeping which is specifically defined, or stated to be, excess emissions by an applicable requirement)

None required to be reported in accordance with Condition No. 8.24.

b. Exceedances: (means for the purpose of this Condition and Condition No. 8.24, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the

results of the monitoring)

i. Any 30-day rolling average NOx emission rate which exceeds 0.07 lb/MMBtu for each PC-Fired Boiler, S01 and S02,

ii. Any 12-month rolling average NOx emission rate which exceeds 0.05 lb/MMBtu for each PC-Fired Boiler, S01 and S02, this condition becomes effective 6 months after initial start-up of each PC-Fired boiler, S01 and S02, absent approval by the Division for an extension of this date.

iii. Any 1-hour average CO emission rate which exceeds 0.30 lb/MMBtu for each PC-Fired Boiler, S01 and S02,

iv. And 30-day rolling average CO emission rate which exceeds 0.15 lb/MMBtu for each PC-Fired Boiler, S01 and S02,

v. Any 24-hour block average for filterable PM emission rate which exceeds 0.01~~5~~**2** lb/MMBtu for each PC-Fired Boiler, S01 and S02,

vi. Any 24-hour average sulfur dioxide emission rate which exceeds 0.12 lb/MMBtu for each PC-Fired Boiler, S01 and S02,

vii. Any 30-day rolling average sulfur dioxide emission rate exceeds 0.065 lb/MMBtu when the uncontrolled sulfur dioxide emission rate is less than or equal to 1 lb/MMBtu on a 30-day rolling average for each PC-Fired Boiler, S01 and S02,

viii. Any 30-day rolling average sulfur dioxide emission rate exceeds 0.08 lb/MMBtu when the uncontrolled sulfur dioxide emission rate is greater than 1 lb/MMBtu but less than 1.25 lb/MMBtu on a 30-day rolling average for each PC-Fired Boiler, S01 and S02,

ix. Any 30-day rolling average sulfur dioxide emission rate exceeds 0.105 lb/MMBtu when the uncontrolled sulfur dioxide emission rate is greater than 1.25 lb/MMBtu but less than 1.6 lb/MMBtu on a 30-day rolling average for each PC-Fired Boiler, S01 and S02,

x. Any annual average mercury emission rate that exceeds 15 x 10^{-6} lb/MW-hr while firing PRB coal for each PC-Fired Boiler, S01 and S02,

xi. Any annual average mercury emission rate that exceeds 6 x 10^{-6} lb/MW-hr while firing CAPP coal for each PC-Fired Boiler, S01 and S02,

xii. Any 24-hour average mercury emissions rate while firing clarifier sludge that exceeds 7.1 lb.

xiii. Any six-minute period during which the average opacity, as measured by a continuous opacity monitoring system for either PC-Fired boiler, S01 and S02, exceeds 20 percent.

xiv. Any time fuel fired in any PC-Fired Boiler, S01 and S02, has a sulfur content which exceeds 3.0 percent sulfur, by weight.

xv. Any time ultra low sulfur fuel oil combusted for startup in PC-Fired boilers, S01 and S02, in auxiliary boiler, S03, in emergency generator S42 and firewater pump S43 exceeds 0.0015 percent sulfur by weight.

xvi. Any twelve consecutive month period during which hours of operation of the auxiliary boiler exceeds 500 hours.

xvii. Any twelve consecutive month period during which hours of operation of emergency generator S42 or firewater pump S43 exceed 500 and 150 hours respectively.

xviii. Any hour that either PC-Fired boiler, S01 and S02, has a heat input rate that exceeds 6,139 MMBtu/hr.

xix. Any calendar day that clarifier sludge combustion in either PC-Fired boiler, S01 and S02, exceeds 1.0 percent of the total heat input rate to the boiler, or 61.4 MMBtu/hr.

~~8.24~~ **8.26** The Permittee shall submit a written report containing the following information for each quarterly period ending March 31, June 30, September 30, and December 31 of each year. All reports shall be postmarked by the 30th day following the end of each reporting period, April 30, July 30, October 30, and January 30, respectively. Reporting required by this condition shall begin at the end of the quarter in which initial startup is completed.
[40 CFR 52.21, 40 CFR 63.7506, and 391-3-1-.02(6)(b)1]

a. The twelve consecutive month total hours of operation of auxiliary boiler, S03, emergency generator S42, and firewater pump S43, each, for each month in the quarterly reporting period. A twelve consecutive month total shall be the total for a month in the reporting period plus the totals for the previous eleven consecutive months.

b. The annual mercury emission rate in lb/MW-hr from each PC-Fired Boiler, S01 and S02, **along with the corresponding weighted average limit determined in accordance with Condition 2.15.m.**

c. The 30-day average NOx emission lb/MMBtu from PC-fired boilers, S01 and S02, for each 30-day average period that ends during the reporting period.

d. The 12-month rolling average NOx emission lb/MMBtu from PC-fired boilers, S01 and S02, for each 11-month average period that ends during the reporting period.

~~d~~ **e**. The 30-day average SO_2 emission lb/MMBtu from PC-fired boilers, S01 and S02, **for each** 30-day average period that ends during the reporting period.

~~e~~ **f**. The coal sampling to determine sulfur content, moisture content, and Gross Caloric Value as required by condition 8.3. Monthly records on the tons of coal burned in Condition 8.4 and the percent ash content as required in Condition 8.5.

~~f~~ **g**. ULSD fuel oil certifications for ultra low sulfur diesel fuel oil burned for startup in each PC-Fired Boiler, S01 and S02, in auxiliary boiler S03, Diesel Emergency Generator S42, and Emergency Firewater Pump S43, <u>and</u> a statement signed by a responsible official of the affected facility that the records of fuel supplier certifications submitted represent all of the ULSD fuel oil was not burned during the quarter, the report should state that no ULSD fuel oil was burned during the quarter.

h. The 24-hour total of mercury emissions (in lbs) from each PC-Fired Boiler, S01 and S02, for each 24-hour period while firing clarifier sludge.

i. The maximum hourly heat input for each PC-Fired Boiler, S01 and S02 during the reporting period.

10.3 The Permittee shall calculate and pay an annual Permit fee to the Division. The amount of the fee shall be determined each year in accordance with the "Procedures for Calculating Air Permit Fees."

APPENDIX A – FINAL PERMIT 4911-099-0030-P-01-0

APPENDIX B – COMMENTS RECEIVED PRIOR TO DRAFT PERIOD

APPENDIX C – COMMENTS RECEIVED DURING PUBLIC COMMENT PERIOD

APPENDIX D – ADDITIONAL CORRESPONDANCE

2. Longleaf Energy Associates – dated January 5, 2007

3. Longleaf Energy Associates – dated March 12, 2007

APPENDIX E – SPREADSHEET OF RECENT COAL-FIRED PLANTS PERMITTED SIMILAR TO LONGLEAF

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BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: **Sevier Power Company Power Plant** **Sevier County, Utah** **DAQE-AN2529001-04**	**EXECUTIVE SECRETARY'S PRE-HEARING BRIEF**

The Executive Secretary of the Utah Air Quality Board (hereinafter "Executive Secretary" or "UDAQ"), by and through the undersigned counsel, submits the following pre-hearing brief in the above-captioned matter.

The Executive Secretary incorporates by reference into this brief Sections I and II of the Executive Secretary's Pre-hearing Brief dated September 19, 2007.

I. INTRODUCTION

On October 12, 2004, the Executive Secretary issued an Approval Order (AO) to Sevier Power Company (SPC) to construct and operate a circulating fluidized bed (CFB) coal-fired power plant in Sevier County, Utah. Although Sierra Club's Second Amended Request for Agency Action (RFA) originally contained 10 claims, Claim Nos. 1, 5, and 6 have been dismissed either by the Board or by Sierra Club. The Board heard Claim Nos. 3, 4, 7, 8, 9 and part of Claim No. 10 on October 1 and 3, 2007. The remaining claims are Claims No. 2,and Claim No. 10 only to the extent that Sierra Club challenges the adequacy of the 18 month review

with respect to the review of Best Available Control Technology limitations for the AO. The Executive Secretary denies all of Sierra Club's claims. This Brief addresses Sierra Club's Claim No. 2, and No. 10 to the extent that it raises BACT as an issue.

II. SIERRA CLUB'S CLAIM

The summary of the issue in dispute is as follows:

Sierra Club's Claim No. 2: UUDAQ Failed to Consider Adequately Integrated Gasification Combined Cycle in its BACT Determination for the Sevier Power Company Facility

In attainment areas, the PSD regulations require that new major stationary sources (such as Sevier Power's proposed facility) must apply the "best available control technology," or "BACT," to control emission of regulated pollutants that the source would have the potential to emit in significant amounts. 42 U.S.C. § 7475(a)(4). At the time of the SPC permit review, BACT was defined by state rule in relevant part as follows:

> The term "best available control technology" means an emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant.

Utah Admin. Code R307-101-2 (2004).

Therefore, BACT is an "emission limitation and/or other controls" to control emissions from an "emitting installation" that the Executive Secretary "determines is achievable for such installation." Id.

The fundamental point of contention between the UDAQ and Sierra Club is whether the UDAQ should have required SPC to consider Integrated Gasification Combined Cycle (IGCC)

process technology in the BACT analysis it submitted for its proposed project, in this case a Circulating Fluidized Bed (CFB) boiler. The testimony submitted by Sierra Club's expert that focuses primarily on IGCC as an "innovative fuel combustion technique" and then concludes that as a consequence, regardless of the technology proposed by the applicant, IGCC it should have been considered under the BACT requirement. And then, by applying the top-down criteria, asserts that IGCC should not only have been considered, but also recognized as BACT.

Two fundamental points of analysis that Sierra Club's expert either ignores or deems insignificant for purposes of the BACT requirement are: (1) whether IGCC can be applied as an emission control technology to a CFB boiler; and (2) whether replacing the proposed CFB coal-fired power plant with an IGCC facility would constitute a fundamental redefinition of the source. These questions have been deemed by the Seventh Circuit Court of Appeals, the EPA's Environmental Appeals Board, the Environmental Protection Agency (EPA), as well as the UDAQ, and the vast majority of other state permitting authorities to be determinative on the issue of whether a distinct process technology such as IGCC even enters into the BACT equation.

A. IGCC Cannot be Added as an Emission Control Technology to a CFB Boiler.

1. UDAQ's Actions

In reviewing SPC's BACT analysis, the Executive Secretary chose to follow the EPA-recommended top-down methodology. The United States Supreme Court has described the top-down method as follows:

> [T]he top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent-or 'top'-alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not 'achievable' in that case. If

> the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Alaska Dep't. of Envtl. Conservation v. EPA, 540 U.S. 461, 475-76 (2004) (*quoting* EPA's New Source Review Workshop Manual at B.2 (Draft Oct. 1990) (hereinafter "NSR Manual")).

The Executive Secretary reviewed the BACT analysis provided with SPC's Notice of Intent (NOI) and independently evaluated all control technologies with potential application to SPC's proposed CFB boiler. (SPC 0137-75; 0369-0738; 1030-52). The Executive Secretary wanted his staff to be particularly well versed on the BACT issue. Expertise and experience were augmented with additional trainings, and the Executive Secretary brought in what he considered to be the preeminent consulting firm on New Source Review permitting in the country as a consultant to provide independent expert third party review of the Intent to Approve, and the BACT analysis in particular. (Pre-Filed Testimony of Richard W. Sprott, October 22, 2007, not paginated) (hereinafter Sprott Testimony).

The Executive Secretary's BACT analysis ultimately did not require SPC to consider the use of IGCC because he did not consider IGCC to be a control technology that could be applied to SPC's proposed installation, a CFB boiler. (Pre-filed Testimony of John Jenks, October 22, 2007 at 9-10) (hereinafter Jenks Testimony) (Pre-Filed Testimony of Rusty Ruby, October 23, 2007, not paginated)(hereinafter Ruby Testimony). SPC did not include IGCC process technology in its list of potential control options in Step One of its BACT analysis, nor did the Executive Secretary ever consider IGCC to be a required aspect of his review of SPC's BACT analysis.

In considering the IGCC issue, the UDAQ considered IGCC as a technology and whether it could be added to CFB as an emission control, the UDAQ's historical application of the BACT requirement, EPA guidance on application of the federal BACT requirement, consulted with

experts in NSR permitting, and considered what permitting authorities from other states were doing with regard to IGCC. (Ruby Testimony, not paginated; Jenks Testimony at 6-9).

2. Sierra Club's Allegations

Sierra Club's basic allegation is that "UDAQ failed to consider adequately Integrated Gasification Combined Cycle in its BACT determination for Sevier Power Company Facility." (Second Amended Request for Agency Action at 4). Sierra Club states in its RFA that it considers IGCC to be a "production process" and "*a method of producing electricity* by gasifying coal, removing pollutants -- including greenhouse gases -- before combustion, and then burning the 'clean' syngas in *a modified combined cycle gas-fired power plant*." Sierra Club RFA at 4 (emphasis added). The UDAQ agrees with the Sierra Club that IGCC is a distinct production process from the CFB boiler proposed by SPC. Since the parties agree that IGCC is a distinct production process, the dispute between the parties is whether such an entirely separate installation must be considered as part of the BACT analysis for a proposed installation.

B. Production Processes which would Redefine the Design of the Source are not Required to be Considered as Part of the BACT Analysis.

1. The Executive Secretary's Approach to Conducting the BACT Analysis is Consistent Squares with Federal Guidance and Case Law

The EPA's Environmental Appeals Board has consistently held that the BACT requirement not be used to redefine the basic design or scope of a proposed project. See In re Knauf Fiber Glass, GMBH, 8 E.A.D. 121, 140 (EAB 1999); see also In re Old Dominion Electric Cooperative Clover, Virginia, 3 E.A.D. 779, 793 n.38 (Adm'r 1992); In re Pennsauken County, New Jersey, Resource Recovery Facility, 2 E.A.D. 667, 673 (Adm'r 1988). The NSR Manual also states that "production processes" or "available methods, systems and techniques for control of each such pollutant" that would "redefine the design of the source" need not be included in the BACT analysis. (NSR Manual at B.13-14).

This principle against redefining the source was recently confirmed by the Seventh Circuit Court of Appeals. In 2006, Sierra Club appealed a permit issued by the EPA on a proposed 1,500 megawatt coal-fired pulverized coal electrical generating plant in southern Illinois. Sierra Club v. EPA, 499 F.3d 653, 654 (7th Cir. 2007). The proposed plant was to be called a "mine-mouth" plant because it had been sited at the location of a coal seam. Id. The siting of the plant near the seam would permit the coal to be brought by a conveyor belt from the mine to the plant. Id. This coal had high sulfur content, but to burn low-sulfur coal Prairie State would have to arrange for the coal to be transported from mines more than a thousand miles away, as well as make changes in the design of the plant. Id. As a new major emitting facility, the Prairie State plant would be required to apply the best available control technology for each pollutant subject to regulation, and Sierra Club argued that the EPA should have been required to decide whether hauling low-sulfur coal from afar would be the best available means of controlling air pollution from the plant. The Environmental Appeals Board determined that burning such transported low-sulfur coal would require the redesign of Prairie State's plant, and therefore was not required to be considered under the BACT analysis. See In re Prairie State, 2006 WL 2847225 (EAB 2006). Sierra Club appealed the decision of the Environmental Appeals Board to United States Court of Appeals for the Seventh Circuit.

In Sierra Club v. EPA, 499 F.3d 653 (7th Cir. 2007), the Seventh Circuit affirmed the ruling by the Environmental Appeals Board that best available control technology does not include redesigning the plant proposed by the permit applicant. The court distinguished between "'control technology' as a means of reducing emissions from a power plant or other source of pollution and redefining the 'proposed facility' (the plant or other source) -- changing its 'fundamental scope.'" Id. at 655. Distinguishing between adopting a control technology and redesigning the proposed plant, the court stated that "[t]he project that must be addressed when evaluating BACT is the project for which an application has been submitted, i.e., a proposed mine-mouth power plant. Accordingly, the use of a particular coal supply is an inherent aspect

of the proposed project. To require an evaluation of an alternative coal supply . . . would constitute a fundamental change to the project." Id. at 656, quoting In re Prairie State Generating Co., 2006 WL 2847225 (EAB 2006).

Notably, just as Sierra Club seems to be doing in this case, Sierra Club in Prairie State "pitch[ed] their case on the naked proposition that if a plant is capable -- with redesign -- of burning a clean fuel, it must undergo a 'best available control technology' analysis. Id. at 656. However, the court stated that "traditionally, EPA does not require a . . . [permit] applicant to change the fundamental scope of its project." Id. at 654, quoting In re Old Dominion Electric Cooperative, 3 E.A.D. 779, 793 n.38 (EPA Adm'r 1992); NSR Manual at B.13.

Then, quoting language directly from the federal BACT definition, the court held that "[r]efining the statutory definition of 'control technology' – 'production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment of innovative fuel combustion techniques' -- to *exclude redesign* is the kind of judgment by an administrative agency to which a reviewing court should defer." Id. At 655 (emphasis added), quoting Environmental Defense v. Duke Energy Corp, 127 S.Ct. 1423, 1434 (2007); New York v. EPA, 413 F.3d 3, 19-20 (D.C. Cir. 2005); Alabama Power Co. v. Costle, 636 F.2d 323, 397-98 (D.C. Cir. 1979). Regarding this "crucial question where control technology ends and a redesign of the 'proposed facility' begins," the court concluded: "[a]s it is not obvious where to draw that line either, it makes sense to let the EPA, the author of the underlying distinction, draw it within reason." Id. At 655.

The EPA policy that consideration of IGCC not be required in the BACT analysis for a proposed conventional coal-fired power plant was reiterated earlier this year in the EPA's Response to Public Comments dated August 30, 2007, in the permitting of the Bonanza Power Plant in eastern Utah. (See excerpt of EPA's Response to Public Comments attached to Jenks Testimony as Exhibit A.)

2. The Executive Secretary's Approach Is Also Consistent with How Other State Permitting Authorities Apply Their BACT Rules.

Understanding that IGCC was a technology of interest, the UDAQ evaluated what other states were requiring with regard to considering IGCC in the BACT analysis and found only three states where state permitting authorities had required some consideration of IGCC as a control option in BACT analyses for conventional coal-fired power plants. (Jenks Testimony at 8-9). Those states were Illinois,[1] New Mexico, and Montana, although Montana appears to have since reversed its position.[2] None of these permitting authorities, however, have gone so far as to conclude that IGCC is BACT for any of those projects. Other states that have studied this issue that have reached the same conclusion as the UDAQ include: Arkansas, Colorado, Florida, Georgia, Kansas, Kentucky, Louisiana, Missouri, Nebraska, Nevada, North Carolina, North Dakota, Pennsylvania, South Dakota, Texas, West Virginia, Wisconsin, and Wyoming. (Pre-filed Testimony of Colin M. Campbell, August 31, 2007 at 10-11).

Wisconsin, for example, when confronted with this same question, determined that IGCC does not qualify for consideration in the BACT analysis because IGCC cannot be applied to the installation as proposed, and would thus redefine the source: "IGCC is not a 'production process' or an 'available method, system, or technique' that can be applied or incorporated into the design of an SCPC unit.

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[1] In its permitting of the Prairie State proposed pulverized coal facility, the Illinois EPA ("IEPA") opted to not reject IGCC as BACT until step 2 of its BACT analysis. Sierra Club argued that IEPA erred by rejecting IGCC as a method of controlling SO2 and NOx emissions without a detailed step 4 analysis. In rejecting Sierra Club's argument, the Environmental Appeals Board noted that "IGCC is not simply an add-on emissions control technology, but instead would have required a completely redesigned 'power block,'" and "extensive design changes to Prairie State's proposed facility." See In re Prairie State, 2006 WL 2847225. The IGCC claim was not an issue on appeal and thus not addressed in the Seventh Circuit Court of Appeals decision.

[2] In its recent permitting of the Highwood Generating Station dated 05/11/07, the Montana Department of Environmental Quality determined that inclusion of technologies such as IGCC in the BACT analysis for the Circulating Fluidized Bed coal-fired power plant proposed by Highwood Generating Station constitutes redefinition of the source and is not appropriate under the BACT analysis. Montana, therefore, appears to have joined the majority of states to consider the issue.

Rather, *IGCC is an altogether different method of generating electricity that would involve the wholesale substitution of one type of physical plant for another.*" In re Wisconsin Electric Power Co., 2005 WL 3450602 (Wisc. Div. Hrg. App. Feb. 3, 2005) (emphasis added).

3. The Executive Secretary's Approach Meets the BACT Requirement

The approach described above meets the BACT requirement that the Executive Secretary consider "application of production processes or available methods, systems and techniques" to "control" contaminants from a proposed installation. See Utah Admin. Code R307-101-2. The Executive Secretary does not, however, dictate what type of facility the permit applicant must build. ("permit conditions defining the emissions control systems 'are imposed on the source as the applicant has defined it' and that 'the source itself is not a condition of the permit.'" In re Prairie State Generating Co., 2006 WL 2847225 (EAB 2006), quoting In re Pennsauken County, New Jersey, Resource Recovery Facility, 2 E.A.D. 667, 673 (Adm'r 1988)). By contrast, Sierra Club's application of the BACT requirement would have the permitting authority "redefining the source" by substituting one design process for an entirely different design process. (NSR Manual at B.13).

With that said, although the source is allowed to define the proposed installation, the UDAQ is not compelled to accept every aspect of the proposed design. Process and design changes are permissible, provided that such changes do not redefine the fundamental design of the source. See In re Prairie State, 2006 WL 2847225 (EAB 2006). Thus, the UDAQ is not (as Sierra Club would suggest), relying on an applicant's "say-so" as to which aspects of the process design are fundamental and which are not. Id. UDAQ's expert Colin Campbell explains this concept in his pre-filed testimony:

> The Sierra Club is correct that the definition of BACT includes a reference to 'application of production processes or available methods, systems, techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.' However, Sierra Club misconstrues this provision and its importance in the definition. The quoted language simply defines the permissible breadth of the agency's considerations in determining 'the degree of reduction' that

> 'is achievable for such source.' Thus, it was proper for the DAQ to consider first the design of the source as proposed, and then to identify and evaluate control options for application to that source.' Process design modifications can be considered as control options within these bounds, so long as those modifications do not require a fundamental redefinition of the design of the source. This is necessarily a judgment call, and it is within the DAQ's expertise to make this call.

Campbell Testimony at 5.

The varying determinations of different state permitting authorities on the inclusion of IGCC in a BACT analysis for coal-fired power plants reflect the discretion that the law affords them to include in the BACT analysis a production process that would redefine the design of the source. See In re Kendall New Century Dev., PSD Appeal No. 03-01, 2003 WL 21213227, n.14 (E.P.A. April 29, 2003) ("redefinition of the source is not always prohibited, but is a matter for the permitting authority's discretion").

Notably, Sierra Club's expert says nothing at all about applying IGCC as a control technology to the proposed CFB boiler, but instead states that an IGCC installation would be feasible at the SPC "site." (Pre-Filed Testimony of John Thompson, August 31, 2007 at 20)(hereinafter Thompson Testimony). By claiming that an IGCC plant could be built on the proposed SPC site, Sierra Club admits that what it seeks is not an application of control technology to control emissions from the CFB boiler, but a total replacement of the proposed CFB boiler with an IGCC facility. Therefore, rather than address IGCC as BACT for a CFB boiler, Sierra Club's expert instead argues that IGCC is the best *process* for converting coal into useful energy, thus acknowledging the CFB boiler process proposed by SPC for purposes of comparison. Whether IGCC can be applied as an emission control technology to a CFB boiler is apparently deemed insignificant in the BACT analysis, as Thompson acknowledges that they are very different: "[w]hile CFB, PC and IGCC share common processes," i.e., converting coal into useful energy, "the equipment used to accomplish these processes is very different among the three technologies." (Thompson Testimony at 5). Thus, the Sierra Club's reading of the BACT definition would give little, if any consideration to the source as proposed by the applicant.

For purposes of determining what will be material evidence to the Board in ruling on Sierra

Club's claim, the question that needs to first be answered is whether IGCC can be added as an emission control to the source as defined by the applicant, which in this case is a CFB boiler, or whether it would redefine this source. If it would redefine the source, then the Executive Secretary was correct in excluding IGCC from Step One of the BACT analysis, and in giving it no further consideration.

C. Sierra Club's Argument that BACT is Meant to be "Technology Forcing" is Misapplied.

Sierra Club's expert argues that BACT requirement is intended to be "technology forcing" and that an interpretation of redefining the source to preclude important design changes would not allow future regulators to force developers who propose 'old' pulverized coal technology to even to look at new alternatives. (See Thompson Testimony at 40). Sierra Club's argument is flawed first and foremost because Sierra Club ignores the fact that the BACT definition itself has been read by the EPA, the Environmental Appeals Board, the Seventh Circuit Court of Appeals, nearly all of the states to consider the issue (as well as by the UDAQ itself) to not require a redefinition of the source. Second, BACT is technology forcing, but not to the extent of dictating the facility's stated purpose or basic design.

Relying on no precedent, Sierra Club's expert includes in his testimony selected quotes from a senator in a congressional hearing record, attempting to prove that the intended meaning of "innovative fuel combustion techniques" would encompass process technologies such as IGCC. Neither the UDAQ nor the EPA reads the cited legislative history to require a detailed evaluation of IGCC process technology in the BACT analysis for every proposed facility that generates electricity from coal. On this point, the Executive Secretary agrees with the EPA, which, in its Response to Public Comments on the Bonanza permit application stated:

> That Senator Huddleston intended for the phrase "innovative fuel combustion techniques' to encompass "gasification" or "low Btu gasification" does not necessarily require EPA or other permitting authorities to identify the IGCC option as a candidate for further analysis at step 1 of a top-down BACT review. The "innovative fuel combustion techniques" phrase appears in the BACT definition among a list of examples of things included in the phrase "production processes and available methods, systems, and techniques." Thus, the "innovative fuel combustion" language, like the phrase it modifies in the definition of BACT, is limited by other language discussed above that requires

> BACT to be applied to each proposed facility and determined on a case-by-case basis. Thus, even assuming that coal gasification was in all respects an innovative fuel combustion technique for producing electricity from coal, we do not interpret the Clean Air Act to require an "innovative fuel combustion technique" to be subject to a detailed BACT review when application of such technique would redesign the proposed source to the point that it becomes an alternative type of facility.

(See Attachment to Jenks Testimony, EPA's Response to Public Comments on Bonanza permit application, at 13).

D. BACT Analysis Not Required as Part of 18 Month Review

Finally, with regard to Sierra Club's Claim No. 10, Sierra Club attempts to contest the sufficiency of UDAQ staff's consideration of BACT limitations during the 18 month review. Utah Admin. Code R307-401-11, however, includes no BACT analysis requirement and Sierra Club identifies no requirement under that rule to do anything other than determine the status of construction. Although UDAQ staff may have looked at BACT (Jenks Testimony at 10-11; Deposition of John Jenks taken May 30, 2007 at 203), it has never purported to have done a full-fledged "BACT analysis" as would normally be conducted when reviewing an initial NOI. A BACT analysis is only required for new and amended permits under Utah Admin. Code R307-401-6. In this case, at the request of the Executive Secretary, the staff conducted a brief review of technological advancement that post-dated the issuance of the AO, and found nothing to indicate that the BACT determinations for the SPC AO were outdated or otherwise inadequate. Id. As a BACT analysis was not required under R307-401-11, the Executive Secretary's informal review of BACT limitations in connection with the 18 month review cannot be a basis for invalidating the AO.

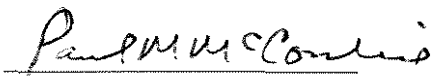
VI. CONCLUSION

Sierra Club makes numerous allegations of failure by the Executive Secretary to properly apply the applicable law regarding the SPC Approval Order. The evidence will show that the

regulation does not require as part of a BACT analysis consideration of distinct production processes (such as IGCC) that cannot be applied to the source as proposed. As a related matter, a BACT analysis is only required prior to issuing an Approval Order. Thus, any post-issuance review of BACT limitations as part of the 18 month review cannot be a basis for invalidating the Approval Order. Because Sierra Club's evidence will not show how the Executive Secretary erred, the Board should deny Sierra Club Claim Nos. 2 and 10.

DATED this 6th day of November, 2007.

MARK L. SHURTLEFF
Utah Attorney General



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CERTIFICATE OF SERVICE

I hereby certify that on this 6th day of November, 2007, I caused a copy of the foregoing to be emailed or mailed by United States Mail, postage prepaid, to the following:

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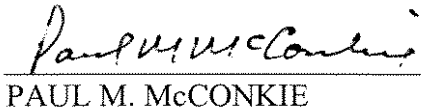

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EXHIBIT A

499 F.3d 653, 65 ERC 1114

Briefs and Other Related Documents

United States Court of Appeals,
Seventh Circuit.
SIERRA CLUB, et al., Petitioners,
v.
U.S. ENVIRONMENTAL PROTECTION AGENCY, Respondent,
and
Prairie State Generating Company, LLC, Intervenor-Respondent.
No. 06-3907.
Argued May 31, 2007.
Decided Aug. 24, 2007.
Rehearing and Rehearing En Banc Denied Oct. 11, 2007.FN*

FN* The Honorable Kenneth F. Ripple did not take part in the consideration or decision of this case.

Background: Environmental organizations brought action under Clean Air Act (CAA), challenging Environmental Protection Agency's (EPA) issuance of permit for coal-fired generating plant in southern Illinois.

Holdings: The Court of Appeals, Posner, Circuit Judge, held that:
(1) CAA provision requiring that air pollution sources be designed to have the best available control technology (BACT) for minimizing pollution was not violated by issuance of permit, and
(2) EPA did not act unreasonably in concluding that plant was unlikely to increase the ozone level in the plant area.

Petition denied.

West Headnotes

[1] KeyCite Notes

149E Environmental Law
149EVI Air Pollution
149Ek266 Particular Sources of Pollution
149Ek269 k. Power-Generating Facilities; Utilities. Most Cited Cases

149E Environmental Law KeyCite Notes
149EVI Air Pollution
149Ek275 Particular Pollutants
149Ek280 k. Sulfur and Sulfur Dioxide. Most Cited Cases

Clean Air Act provision requiring that air pollution sources be designed to have the best available control technology (BACT) for minimizing pollution was not violated by Environmental Protection Agency's (EPA) issuance of permit for coal-fired electrical generating plant located at mouth of mine which produced high-sulfur coal; requiring plant to accommodate shipments of low-sulfur coal from a more distant source would amount to requiring a redesign of the plant, which would be a change of the project's fundamental scope. Clean Air Act, §§ 165(a)(4), 169(3), 42 U.S.C.A. §§ 7475(a)(4), 7479(3).

[2] KeyCite Notes

149E Environmental Law
149EVI Air Pollution
149Ek287 k. Ozone. Most Cited Cases

Environmental Protection Agency (EPA) did not act unreasonably, when issuing permit for mine-mouth coal-fired electrical generating plant, in concluding that plant was unlikely to increase the ozone level in the plant area, even though conclusion was based on use of the superseded 1-hour standard, where a compliance measure tailored to the new 8-hour standard had not yet been adopted; EPA was entitled to use the measure used for the 1-hour standard as a stopgap. Clean Air Act, § 165(a)(3), 42 U.S.C.A. § 7475(a)(3).

*653 Sanjay Narayan (argued), San Francisco, CA, for Petitioners.

Jon M. Lipshultz (argued), Department of Justice, Environmental Defense Section, Washington, DC, for Respondent.

*654 Kevin J. Finto, George P. Sibley, III, Harry M. Johnson, III (argued), Hunton & Williams, Richmond, VA, for Intervenor-Respondent.

Before POSNER, KANNE, and WILLIAMS, Circuit Judges.

POSNER, Circuit Judge.
The federal Environmental Protection Agency (actually, Illinois's counterpart to the EPA, exercising authority that the federal EPA had delegated to it, but we can ignore that detail) issued a permit to Prairie State Generating Company to build a 1,500-megawatt coal-fired electrical generating plant in southern Illinois, near St. Louis. Environmentalists asked the EPA's Environmental Appeals Board to reverse the issuance of the permit, and, the Board having refused, *In re Prairie State Generating Co.,* No. 05-05 (EAB Aug. 24, 2006), they renew the quarrel in this court. They claim that the EPA violated two provisions of the Clean Air Act. One requires as a condition of receiving a permit that a plant or other source of air pollution be designed to have the "best available control technology" for minimizing pollution emitted by the plant. 42 U.S.C. § 7475(a)(4). The other attaches the further condition that the plant's emissions not exceed the limits imposed by the Act's national ambient air quality standards. § 7475(a)(3). The petitioners' first claim relates to the sulfur dioxide that will be produced as a byproduct of the production of electricity by Prairie State's plant, the second to the ozone that it will produce.

The plant is to be what is called a "mine-mouth" plant because it has been sited at the location of a coal seam. The seam is believed to contain 240 million tons of recoverable coal-enough to supply the plant's fuel needs for 30 years. The siting of the plant will enable the coal to be brought by a conveyor belt, more than half a mile long, from the mine to the plant. Unfortunately, this coal has a high sulfur content. To burn low-sulfur coal Prairie State would have to arrange for it to be transported from mines more than a thousand miles away and would have to make changes in the design of the plant-specifically, the design of the plant's facilities for receiving coal. The petitioners argue that the EPA must decide whether hauling low-sulfur coal from afar would be the best available means of controlling air pollution from the plant.

The Clean Air Act defines "best available control technology" as the "emission limitation" achievable by "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment of innovative fuel combustion techniques." 42 U.S.C. § 7479 (3). A "proposed facility" that would if built be a "major emitting facility," as the proposed Prairie State plant would be, must have "the best available control technology for each pollutant subject to regulation," § 7475(4), including sulfur dioxide. The EPA's position is that "best available control

technology" does not include redesigning the plant proposed by the permit applicant ("traditionally, EPA does not require a ... [permit] applicant to change the fundamental scope of its project," *In re Old Dominion Electric Cooperative,* 3 E.A.D. 779, 793 n. 38 (EPA Adm'r 1992); Environmental Protection Agency, "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Permitting" B.13 (Draft, Oct. 1990)), unless the applicant intentionally designs the plant in a way calculated to make measures for limiting the emission of pollutants ineffectual. *In re Prairie State Generating Co., supra,* slip op. at 30, 33-34. But that is not contended in this case. Another provision *655 of the Act, distinct from the one requiring adoption of the best available control technology, directs the EPA to consider "alternatives" suggested by interested persons (such as the Sierra Club) to a proposed facility. 42 U.S.C. § 7475(a)(2); see, e.g., *In re NE Hub Partners, L.P.,* 7 E.A.D. 561, 583 (EAB 1998). But that provision has not been invoked by the petitioners. Only compliance with the "BACT" (best available control technology) requirement is in issue.

The Act is explicit that "clean fuels" is one of the control methods that the EPA has to consider. Well, nuclear fuel is clean, and so the implication, one might think, is that the agency could order Prairie State to redesign its plant as a nuclear plant rather than a coal-fired one, or could order it to explore the possibility of damming the Mississippi to generate hydroelectric power, or to replace coal-fired boilers with wind turbines. That approach would invite a litigation strategy that would make seeking a permit for a new power plant a Sisyphean labor, for there would always be one more option to consider. The petitioners to their credit shy away from embracing the extreme implications of such a strategy, which would stretch the term "control technology" beyond the breaking point and collide with the "alternatives" provision of the statute. But they do not suggest another stopping point.

Now it is true that a difference between this case and our nuclear hypothetical is that a plant designed to burn coal cannot run on nuclear fuel without being redesigned from the ground up, whereas Prairie State's proposed plant could burn coal transported to the plant from afar. But to convert the design from that of a mine-mouth plant to one that burned coal obtained from a distance would require that the plant undergo significant modifications-concretely, the half-mile-long conveyor belt, and its interface with the mine and the plant, would be superfluous and instead there would have to be a rail spur and facilities for unloading coal from rail cars and feeding it into the plant. See Kathryn Heidrich, "Mine-Mouth Power Plants: Convenient Coal Not Always a Simple Solution," *Coal Age,* June 2003, pp. 28, 30; Richard H. McCartney, "Bringing Coal Yards Into the 21st Century," *Power Engineering,* July 2005, p. 36.

So it is no surprise that the EPA, consistent with our nuclear hypothetical and the petitioners' concession regarding it, distinguishes between "control technology" as a means of reducing emissions from a power plant or other source of pollution and redesigning the "proposed facility" (the plant or other source)-changing its "fundamental scope." The agency consigns the latter possibility to the "alternatives" section of the Clean Air Act, which as we said is not involved in this case. Refining the statutory definition of "control technology"-"production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment of innovative fuel combustion techniques"-to exclude redesign is the kind of judgment by an administrative agency to which a reviewing court should defer. *Environmental Defense v. Duke Energy Corp.,* --- U.S. ----, 127 S.Ct. 1423, 1434, 167 L.Ed.2d 295 (2007); *New York v. EPA,* 413 F.3d 3, 19-20 (D.C.Cir.2005); *Alabama Power Co. v. Costle,* 636 F.2d 323, 397-98 (D.C.Cir.1979).

But this opens the further and crucial question where control technology ends and a redesign of the "proposed facility" begins. As it is not obvious where to draw that line either, it makes sense to let the EPA, the author of the underlying distinction, draw it, within reason.

*656 Suppose this were not to be a mine-mouth plant but Prairie State had a contract to buy high-sulfur coal from a remote mine yet could burn low-sulfur coal as the fuel source instead. Some adjustment in the design of the plant would be necessary in order to change the fuel source from high-sulfur to low-sulfur coal, Brian Schimmoller, "Western Coal Pushes East," *Power Engineering,* Aug. 1999, http:// pepei. pennnet. com/ art icles/article_display.cfm? article_id=36230 (visited Aug. 21, 2007), but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a "control technology." Otherwise "clean fuels" would be read out of the definition of such technology. At the other end of the spectrum is our nuclear

hypothetical. The plant proposed in this case falls between that hypothetical example and the example of a plant that has alternative off-site sources of high-and low-sulfur coal respectively.

We hesitate in a borderline case, such as this, to pronounce the EPA's decision arbitrary, the applicable standard for judicial review of its granting the permit. *Alaska Department of Environmental Conservation v. EPA,* 540 U.S. 461, 496-97, 124 S.Ct. 983, 157 L.Ed.2d 967 (2004). The decision required an expert judgment. The petitioners' brief, though long, contains nothing about mine-mouth power stations. The petitioners pitch their case on the naked proposition that if a plant is capable-with redesign-of burning a clean fuel, it must undergo a "best available control technology" analysis. But they flinch by carving an exception for the nuclear case without explaining the principle that distinguishes it from this case. Of course there is a distinction, but it is one of degree and the treatment of differences of degree in a technically complex field with limited statutory guidance is entrusted to the judgment of the agency that administers the regulatory scheme rather than to courts of generalist judges. *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.,* 467 U.S. 837, 842-43, 104 S.Ct. 2778, 81 L.Ed.2d 694 (1984); *Sierra Club v. EPA,* 375 F.3d 537, 539-40 (7th Cir.2004).

What must give us pause, however, is the scantiness of the Environmental Appeals Board's discussion of the difference between, on the one hand, adopting a control technology, and, on the other hand, redesigning the proposed plant, in the specific setting of this case. Here are the critical passages: " 'With respect to alternate sources of coal, e.g., low-sulfur western coal from Wyoming or Montana, the proposed plant is being designed and developed to burn high-sulfur Illinois coal, the locally available coal. It would be inconsistent with the scope of the project to use coal from other regions of the country. Rather, the BACT [best available control technology] determination addresses the appropriate control technology for SO_2 [sulfur dioxide] emissions associated with use of this coal at the proposed plant.... The project that must be addressed when evaluating BACT is the project for which an application has been submitted, i.e., a proposed mine-mouth power plant. The source of coal for which the plant would be developed is a specific reserve of 240 million tons of recoverable coal, which would meet the needs of the proposed plant for more than 30 years. Accordingly, the use of a particular coal supply is an inherent aspect of the proposed project. To require an evaluation of an alternative coal supply ... would constitute a fundamental change to the project.' " *In re Prairie State Generating Co., supra,* slip op. at 20-21. Alternative coal supplies would be " 'beyond the scope of the project, a power plant fueled from *657 coal delivered by a conveyor belt from an adjacent dedicated mine.' " *Id.* at 23. " 'The development of a mine-mouth power plant is an intrinsic aspect of the proposed plant, which would be developed to use a specific reserve of fuel, which is adequate for the expected life of the plant.' ... [C]onsideration of low-sulfur coal, *because it necessarily involves a fuel source other than the co-located mine,* would require Prairie State to redefine the fundamental purpose or basic design of its proposed Facility." *Id.* at 31, 36 (emphasis added).

[1] These passages might be read as merging two separate issues: the difference between low-sulfur (clean) and high-sulfur (dirty) coal as a fuel source for a power plant, and the difference between a plant co-located with a coal mine and a plant that obtains its coal from afar. The former is a difference in control technology, the latter a difference in design (or so the EPA can conclude). We think it is sufficiently clear from the passages that we have quoted from the Environmental Appeals Board's opinion, and especially from the clause that we italized, that the Board did not confuse the two issues; that it granted the permit not because it thinks that *burning* low-sulfur coal would require the redesign of Prairie State's plant (it would not), but because *receiving* coal from a distant mine would require Prairie State to reconfigure the plant as one that is not co-located with a mine, and this reconfiguration would constitute a redesign.

So the Board's ruling on the BACT issue must be upheld, and we move on to the ozone issue. Measuring the contribution of a power plant to atmospheric ozone is difficult because the ozone is not emitted directly by the plant; rather, it is produced by the interaction of some of the chemicals that the plant emits with sunlight. Until 2003 the EPA determined that a power plant was violating the limit on contributing to ozone in the area in which Prairie State's plant is to be located when on at least one day there was an hour in which the average concentration of ozone exceeded .12 parts per

million. But that year it decided to replace the "1 hour" standard as it was called with an "8 hour" standard. The new standard looks at whether the concentration of ozone during an average 8-hour period (more precisely, a three-year average of the fourth-highest daily maximum 8-hour concentration) exceeds .08 parts per million. The agency explained that "the 8-hour standard is more protective of public health and more stringent than the 1-hour standard, and there are more areas that do not meet the 8-hour standard than there are areas that do not meet the 1-hour standard." "Proposed Rule to Implement the 8-Hour Ozone National Ambient Air Quality Standard," 68 Fed.Reg. 32,802, 32,804 (June 2, 2003) (to be codified at 40 C.F.R. Pt. 51).

[2] The concentrations measured over these intervals are not actual measurements of ozone; they are estimates based on the levels of contributing factors, the chemicals and sunlight. The formula for estimating the average ozone concentration in one hour is not necessarily applicable to the 8-hour estimate, but the EPA has yet to adopt a formula for the latter estimate. So it used the 1-hour formula not only to show compliance with the 1-hour standard but also to generate an 8-hour estimate, and it used results from earlier studies of the St. Louis area to reinforce its conclusion. From both the 1-hour formula applied to 8-hour stretches and the earlier studies, the agency concluded that Prairie State's plant would not increase the amount of ozone in the local atmosphere. As best the agency could estimate, its 1-hour measurement would turn out to be *below* the limit of .08 parts per million that the EPA has set for the 8-hour limit.

*658 This was a plausible expectation because, as a matter of arithmetic, the emissions in the highest hour of a measurement period have to be at least as great as the emissions averaged over the highest eight hours in that period. Suppose the emissions in the highest hour are 10 parts per million, in the next highest hour 9 parts per million, then 8 parts, 7, 6, 5, 4, and 3. The average would be 6.5, which would have to be lower than the amount in the highest hour (10) unless the emissions were the same in every hour, in which event the 1-hour and the 8-hour averages would be identical. Admittedly, the example oversimplifies the case because different methods of averaging are used for the different standards. But an emissions level that satisfies the 1-hour standard is likely though not certain to satisfy the new standard as well even though the agency considers the latter to be more stringent.

The petitioners argue that the EPA simply cannot be permitted to rely on the 1-hour standard because it has been superseded by the 8-hour standard. It has; but pending adoption of a compliance measure tailored to the new standard, the agency was entitled to use the measure used for the older standard as a stopgap to demonstrate that if the plant complied with that measure it would be unlikely to violate the new standard. The petitioners do not suggest an alternative except to criticize the inference the agency drew from earlier studies. The criticisms have some merit but not enough to enable us to conclude that the agency was unreasonable in concluding that the plant is unlikely to increase the ozone level.

The petition for review is

DENIED.

C.A.7,2007.
Sierra Club v. U.S. E.P.A.
499 F.3d 653, 65 ERC 1114

Briefs and Other Related Documents (Back to top)

- 2007 WL 2857611 (Appellate Brief) Reply Brief for Petitioners (Apr. 5, 2007) Original Image of this Document (PDF)
- 2007 WL 959959 (Appellate Brief) Brief of Respondent United States Environmental Protection Agency (Mar. 22, 2007) Original Image of this Document (PDF)
- 2007 WL 959960 (Appellate Brief) Brief for Prairie State Generating Company, LLC (Mar. 22, 2007)

- 2007 WL 414515 (Appellate Brief) Brief for Petitioners (Jan. 19, 2007)
- 06-3907 (Docket) (Oct. 30, 2006)

END OF DOCUMENT

EXHIBIT B

MONTANA AIR QUALITY PERMIT

Issued To:	Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station 3521 Gabel Road, Suite 5 Billings, MT 59102	Permit: #3423-00 Application Complete: 5/16/06 Preliminary Determination Issued: 3/30/06 Supplemental Preliminary Determination Issued: 6/22/06 Department's Decision Issued: 05/11/07 Permit Final: 05/30/07 AFS #013-0038

An air quality permit, with conditions, is hereby granted to Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, as amended, for the following:

SECTION I: Permitted Facilities

A. Permitted Equipment

SME-HGS operates a gross 270-megawatt (MW) electrical power generating plant. The SME-HGS facility is a coal-fired steam/electric generating station incorporating a circulating fluidized bed boiler (CFB Boiler). Auxiliary power to operate the facility is estimated to be approximately 20 MW resulting in an approximate net power production capacity of 250 MW. Emissions from the CFB-Boiler are controlled by CFB limestone injection technology, a fabric filter baghouse (FFB), a hydrated ash re-injection system (HAR), and a selective non-catalytic reduction unit (SNCR). The total CFB-Boiler emission control strategy is characterized as an integrated emission control system (IECS). A complete list of permitted equipment/emission sources is contained in Section I.A of the permit analysis to this permit.

B. Plant Location

The SME-HGS plant encompasses approximately 720 acres of property and is located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 497 kilometers (km), and Northing 5,268 km. The site elevation is approximately 3,290 feet above sea level.

C. Current Permit Action

The Department of Environmental Quality (Department) issued its preliminary determination on air quality Permit #3423-00 on March 30, 2006, and accepted comments on the preliminary determination through May 1, 2006. Further, on April 25, 2006, Bison Engineering, Inc., on behalf of SME-HGS, verbally notified the Department of additional emitting units that were not previously analyzed and permitted under the preliminary determination and were deemed necessary for the construction and operation of the CFB Boiler. Specifically, SME-HGS determined that during the CFB Boiler construction phase and periodically thereafter, as necessary, SME-HGS would need to operate portable/ temporary propane-fired heaters for the purpose of curing the CFB Boiler refractory brick. SME-HGS submitted an application for the proposed additional emitting units on May 16, 2006, and the Department issued a supplemental preliminary determination on Permit

c. PTE > 70 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all major sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #3423-00 for SME-HGS, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for PM, PM_{10}, NO_X, SO_2, and CO.

   b. The facility's PTE is greater than 10 tons/year for a single HAP and greater than 25 tons/year for all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject to NSPS requirements under 40 CFR 60, Subpart(s) A, Da, Db, Y, and OOO.

   e. This facility is subject to NESHAP standards under 40 CFR 63, subpart DDDDD and ZZZZ, as applicable.

   f. This source is a Title IV affected source.

   g. This source is not a solid waste combustion unit.

   h. This source is not an EPA designated Title V source.

   Based on the above information, the SME-HGS facility is a major source of air pollutants as defined under the Title V operating permit program; therefore, a Title V Operating Permit is required. SME-HGS submitted an application for a major source Title V operating permit concurrent with the submittal of the application for Montana Air Quality Permit #3423-00.

III. BACT Determination

A BACT determination is required for each new or modified source of emissions. SME-HGS shall install on the new or modified source of emissions the maximum air pollution control capability that is technically practicable and economically feasible, except that the BACT shall be utilized.

Under the current permit action, SME-HGS proposed a coal-fired power plant incorporating a CFB Boiler for the production of steam to be routed to a steam turbine, which in turn drives an electric generator capable of producing electrical power. The United States Environmental Protection Agency's (EPA) Draft New Source Review Workshop Manual (October 1990) (NSR Manual) states that, "historically, EPA has not considered the BACT requirement a means to re-define the design of the source when considering available control technologies." However, the NSR Manual goes on to indicate "...this is an aspect of the New Source Review – Prevention of Significant Deterioration permitting process in which states have the discretion to engage in a broader analysis if they so desire." Based on the analysis provided below, the Department does not believe that redefining the source is appropriate in this case.

In support of the Department's position on this issue, a recent EPA policy/guidance statement titled *Best Available Control Technology Requirements for Coal-Fired Power Plants,* authored by Stephen D. Page, Director, EPA Office of Air Quality, Planning, and Standards (December 13, 2005), provides that inclusion of technologies such as integrated gasification combined cycle (IGCC) in the BACT analysis for a coal-fired power plant, such as that proposed in this case, constitutes re-

definition of the source and is not appropriate under the BACT analysis and determination process. Since issuance of the Department's preliminary determination and supplemental preliminary determination on Permit #3423-00, EPA has indicated that the policy described in this memo does not constitute a final EPA action on this issue but does constitute the EPA's legal opinion on the issue at this time.

Despite the above-cited reasons for not requiring consideration of other energy production processes, during the research and development phase leading to the proposed SME-HGS project, SME-HGS evaluated various alternative energy technologies including the following: Wind; Solar - Photovoltaic; Solar - Thermal; Hydroelectric; Geothermal; Biomass; Biogas; Municipal Solid Waste; Natural Gas Combined Cycle; Microturbines; Pulverized Coal (PC) Boilers; CFB Boilers; and IGCC. This analysis is compiled in a document created for the U.S. Department of Agriculture, Rural Utility Service (RUS) titled, *Alternative Evaluation Study* (AES). A copy of this document is available for review on the RUS website at www.usda.gov/rus/water/ees/eis.htm and in Appendix D of the SME-HGS application for this air quality permit. This document constitutes a detailed study of alternative energy technologies that were analyzed for future power requirements. The purpose of the AES, as stated in the AES document is "...to determine *an appropriate source of wholesale electric energy and related services post 2008...Provide an analysis of alternatives that SME-HGS has considered to meet its wholesale energy and related supply obligations currently met through the use of power purchase agreements...The alternatives studied by SME-HGS were evaluated in terms of cost effectiveness, technical feasibility, and environmental soundness."*

Additional Evaluation of IGCC and PC Technology

As previously stated, the Department determined that re-defining the proposed CFB coal-fired power project is not appropriate in this case. However, because IGCC and PC technologies represent available and technically feasible electrical power production technologies using coal as fuel, the following information provides additional reasons for rejecting these technologies as BACT for the proposed SME-HGS project based on technical, environmental, and economic factors.

IGCC Power Generation

Based on the analysis included in the SME-HGS application materials and independent Department research, the Department determined that IGCC represents an available and potentially technically feasible strategy for the production of electricity using coal. However, the Department determined that IGCC is technically, economically, and environmentally infeasible for the purpose of meeting the SME-HGS wholesale energy and related supply obligations to its energy cooperative customers.

As provided in the NSR Manual (Section B-19), an analysis of technical feasibility should include an evaluation of the capabilities of the technology for project specific application. At the time of permit issuance, IGCC has not been adequately demonstrated to provide acceptable reliability, with current approaches to improving reliability resulting in less efficient facilities thereby negatively impacting the cost-competitiveness of IGCC for a base-load power generation project. Currently, IGCC incurs an approximate 20% increase in project cost-effective values when compared to CFB power production projects. Therefore, the Department determined that the application of IGCC for the proposed SME-HGS project presents currently un-resolvable reliability concerns leading to unacceptable project cost increases.

Further, based on Department analysis of existing and currently operational similar sized IGCC plant operations, the Department determined that criteria pollutant emissions from IGCC plants, when compared to CFB technology, result in relatively little or no additional environmental protection. The Department understands that the carbon sequestration (greenhouse gas reduction) capabilities of the IGCC technology potentially represent a significant environmental benefit associated with the application of this technology when compared to historically prevalent coal-fired power plant

projects (CFB and PC). However, greenhouse gasses, such as carbon dioxide (CO_2), are not currently regulated under the Montana or federal Clean Air Act. Therefore, because IGCC results in relatively little increased regulated environmental protection, the environmental benefits associated with IGCC greenhouse gas sequestration capabilities do not justify application of this technology for the proposed project.

As summarized above, the Department determined that, at this time, IGCC constitutes a technically, economically, and environmentally infeasible alternative electric power production alternative for the proposed SME-HGS project; therefore, IGCC is eliminated from further consideration under the BACT analysis and determination process.

PC-Boiler Power Generation

Based on the analysis included in the SME-HGS application materials and direct recent and historical Department experience in permitting PC-fired electrical power production projects, the Department determined that PC-fired electrical power production represents an available, technically feasible, and cost-effective strategy for the production of electricity using coal. However, the Department determined that PC-fired electrical power generation does not constitute BACT in this case considering the environmental benefits associated with the proposed CFB coal-fired power project when compared to a PC coal-fired power project.

Operation of a PC-fired boiler in place of the proposed CFB Boiler for the SME-HGS project would result in significantly increased emissions of SO_2, CO, PM_{10}, and total HAPs and relatively similar emissions of NO_x and mercury (specific HAP). Therefore, because SME-HGS proposed a CFB electrical power generation project and the CFB technology would result in less emissions of regulated air pollutants when compared to the PC-fired technology, the Department determined that PC-fired electrical power generation does not constitute BACT in this case.

Project BACT Applicability

The Department determined that the proposed CFB coal-fired power plant represents the most appropriate technology to supply energy to SME-HGS customers taking into consideration technical, environmental, and economic factors. Coal-fired electrical power generation, specifically CFB coal combustion is carried forward into the following BACT analysis and determination process. The following BACT analysis addresses available methods of controlling air pollutant emissions from the following affected equipment:

- CFB Boiler: SO_2, filterable PM, PM_{10} (filterable and condensable), NO_x, CO, VOC, H_2SO_4, acid gasses (HCl and HF), trace metals, radionuclides, and mercury.
- Coal, Limestone, and Ash (Bottom and Fly Ash) Material Processing, Handling, Transfer, and Storage Operations: PM/PM_{10}.
- Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater: PM_{10}, NO_x, CO, SO_2, and VOC.
- Cooling Tower: PM/PM_{10}.
- Haul Roads/Truck Traffic: PM/PM_{10}.
- CFB Boiler Refractory Brick Curing Heaters: PM_{10}, NO_x, CO, SO_2, and VOC.

A. CFB Boiler BACT Analysis and Determination

Startup of a CFB Boiler is a three-phase operation that can take up to 48 hours depending on the initial furnace temperature and conditions of the fluidized bed. During the three-phase startup process, the unit steps through a series of changes to reach full load firing on coal with the addition of limestone into the CFB furnace. During this process, CFB Boiler emissions and emission control strategies may vary until BACT-determined air pollution

File

BEFORE THE
UTAH AIR QUALITY BOARD

In the Matter of:	*	
	*	Findings of Fact, Conclusions of Law, and Final Order
Sevier Power Company Power Plant Sevier County, Utah DAQE-AN2529001-04	*	
	*	

The Utah Chapter of the Sierra Club (referred to herein as "Sierra Club") filed a Request for Agency Action dated November 12, 2004 and petition to intervene seeking review of the October 12, 2004 decision by the Executive Secretary of the Utah Air Quality Board to issue an Approval Order granting a permit to Sevier Power Company ("SPC") to construct and operate a coal-fired power plant in Sevier County, Utah. The Sierra Club presented nine issues for consideration of the Board. The Utah Air Quality Board denied Sierra Club's petition to intervene, which was appealed. The Utah Supreme Court, on November 21, 2006, determined Sierra Club had made a sufficient demonstration to support intervention and remanded the matter to the Board for hearing. PacifiCorp had also filed a petition to intervene, which was initially denied, but as a result of the Utah Supreme Court decision, PacifiCorp renewed its petition to intervene. The Board granted PacifiCorp intervention on Issue 2 of the Sierra Club's Request for Agency Action. Sierra Club filed a Motion for Leave to Amend its Request for Agency Action that was granted by the Board, which added an Issue 10.

On April 4, 2007, the Utah Air Quality Board heard dispositive motions from all parties on Sierra Club's Requests for Agency Action. Joro Walker and David Becker appeared for the Sierra Club; Brian W. Burnett and Fred W. Finlinson appeared for SPC; Martin K. Banks

appeared for PacifiCorp; and Paul M. McConkie and Christian C. Stephens appeared for the Executive Secretary. Utah Air Quality Board members present were Dianne R. Nielson, Wayne M. Samuelson, H. Craig Petersen, James R. Horrocks, Nan Bunker, Stead Burwell, Stephen C. Sands, Don J. Sorensen, Kathy Van Dame, and Darrell Smith. Mr. Sands and Ms. Van Dame recused themselves. Mr. Ernest E. Wessman had earlier recused himself and left the proceedings. The Board denied all motions with the exception of the Motions for Judgment on the Pleadings by SPC, PacifiCorp, and the Executive Secretary on Issue 1, which was granted.

Sierra Club subsequently withdrew issues 5 and 6, leaving issues 2, 3, 4, 7, 8, 9, and 10 to be heard by the Board at hearings on October 1, 2007, October 3, 2007, November 7, 2007, and November 12, 2007. The Board heard this matter pursuant to its authority as set forth in Chapter 2 of Title 19 of the Utah Code and conducted the proceeding pursuant to the provisions of Utah Administrative Code ("UAC") R307-103 et seq. as a formal adjudicative proceeding under the provisions of the Administrative Procedures Act as set forth in Utah Code Ann. § 63-46b-8. Joro Walker and David Becker appeared for the Sierra Club, Brian W. Burnett and Fred W. Finlinson appeared for SPC, and Paul M. McConkie and Christian C. Stephens appeared for the Executive Secretary. Issue 2 was heard on November 12, 2007, and in addition to the counsel listed above, Martin K. Banks and Michael Jenkins appeared for PacifiCorp. At those hearings, Utah Air Quality Board members present were Wayne M. Samuelson, H. Craig Petersen, James R. Horrocks, Nan Bunker, Kathy Van Dame (who recused herself), Joel E. Elstein, Richard W. Sprott (who recused himself) and Darrell Smith. Board member Stead Burwell was also in attendance for all but the October 1, 2007, hearing. He reviewed the transcript and evidence from that hearing date. Mr. Ernest Wessman and Mr. Stephen C. Sands had previously recused

themselves and were not present.

In all the proceedings and hearings, Fred Nelson acted as counsel for the Board.

The underlying issue before the Board is whether the Executive Secretary complied with State statutes and the Utah Air Quality Board rules in issuing the October 14, 2004, Approval Order to Sevier Power Company. To prevail, petitioners have the burden of proving that the Executive Secretary failed to comply with State air quality requirements. "[T]he proper standard of proof in the administrative context is generally the 'preponderance of the evidence' standard." *Harken SW. Corp. v. Bd. of Oil, Gas & Mining*, 920 P.2d 1176, 1182 (Utah 1996).

The Board makes the following findings, conclusions, and final order with respect to each of the issues presented by Sierra Club:

Issue 1

Issue 1 is whether the Executive Secretary failed to address carbon dioxide and other greenhouse gases relating to the SPC Plant. The Board granted the Motions for Judgment on the Pleadings by SPC, PacifiCorp, and the Executive Secretary on this Issue 1 by a vote of seven in favor (Nielsen, Peterson, Burwell, Samuelson, Smith, Bunker, and Sorenson) and none opposed based on the following findings and conclusions that are restated as part of this final order.

While the United States Supreme Court has recently determined that carbon dioxide and other greenhouse gases come within the definition of "air pollutant" subject to regulation under the federal Clean Air Act (Massachusetts v EPA, 127 S.Ct. 1438 (April 2, 2007)), neither the EPA (as recognized in the U.S. Supreme Court opinion) nor the Utah Air Quality Board have, to date, adopted rules requiring limitations or consideration of carbon dioxide or other greenhouse gases as part of a new source review or a BACT determination. The definition of "air pollution"

as defined in U.C.A. § 19-2-102(3) over which the Board has authority to control and regulate (U.C.A. § 19-2-104) is "the presence in the ambient air of one or more air contaminants in the quantities and duration and under conditions and circumstances as is or tends to be injurious to human health or welfare . . . as determined by the rules adopted by the board." Inasmuch as the Board has never adopted rules governing carbon dioxide or other greenhouse gases, it has not, as a matter of law, required limitations or consideration of carbon dioxide or other greenhouse gases as part of the approval order or permit process.

The Board rejected Sierra Club's argument that the definition of BACT requires consideration of all pollutants that could be regulated, to include carbon dioxide and other greenhouse gases. The Board interprets the language of its rule to mean that the phrase "pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act" in the definition of BACT (UAC R307-101-2) references pollutants for which the Board has established rules, not pollutants that could potentially be subject to rules. Since the Board has not promulgated rules governing carbon dioxide or other greenhouse gases, the Executive Secretary had no rules to enforce, and, with respect to the issue of not requiring limitations and consideration of carbon dioxide and other greenhouse gases, the Executive Secretary correctly, as a matter of law, issued the Approval Order to SPC without addressing carbon dioxide or other greenhouse gas emissions.

Issue 2

Issue 2 is whether the Executive Secretary failed to consider adequately Integrated Gasification Combined Cycle ("IGCC") in its Best Available Control Technology ("BACT") determination for the SPC facility.

On November 12, 2007, the Board upheld the actions of the Executive Secretary on Issue 2 by a vote of six in favor (Horrocks, Peterson, Samuelson, Smith, Bunker, and Elstein) and one opposed (Burwell) based on the following findings and conclusions.

Findings of Fact

1. A party intending to construct a "major" new source in a NAAQS attainment area must first obtain an approval order. UAC R307-401-1 (references to the Board's rules in the findings and conclusions of this order are the rules in effect at the time of the issuance of the Approval Order to SPC).

2. The applicant for an approval order must demonstrate that the new source will employ BACT for each criteria pollutant emitted. UAC R307-401-6.

3. UAC R307-101-2(4) defines BACT as follows:

> [A]n emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such installation through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant . . . .

4. SPC filed an application, a Notice of Intent ("NOI"), asking the Executive Secretary for an approval order to allow SPC to build a power plant utilizing a Circulating Fluidized Bed ("CFB") boiler in conjunction with a limestone injection and a dry lime scrubber for sulfur dioxide control, along with selective non-catalytic reduction ("SNCR") with ammonia injection as a post-combustion control device for NOx control. SPC 0052-0738.

5. After an applicant has proposed the type of installation or power generation

technology, then through the BACT analysis the applicant must identify available emission control technology options for the particular installation proposed. Campbell Pre-Filed Testimony, August 31, 2007 at 5. Campbell Hearing Testimony, November 12, 2007 at 265-273, 290.

6. In doing a BACT review, a "top-down" method, though not required, may be used for determining BACT as follows: (1) identify control technology options ("Step 1"), (2) eliminate technically infeasible control technologies, (3) rank remaining technologies, (4) evaluate the most effective controls, and (5) select the most effective remaining option. EPA's Draft New Source Review Workshop Manual ("Draft NSR Manual"), at B.5.

7. In review of the SPC application for an approval order, the Executive Secretary determined that IGCC had not been proposed by SPC and that IGCC was a different power generation technology and not a "control technology" to be considered under Step 1, and therefore, did not include IGCC in assessing what was BACT for the proposed facility. September 27, 2004 Memorandum to Sevier Power Plant File, at 30, SPC 2523. Jenks Pre-Filed Testimony, October 22, 2007, at 9-10. Jenks Hearing Testimony, November 12, 2007, at 37.

8. Sierra Club argued that IGCC is a production process and existing available technology that should have been considered in any BACT determination for the SPC plant, and presented information on plants in the United States and Europe. Thompson Pre-Filed Testimony, August 31, 2007, at 5-41. Thompson Pre-Filed Testimony, November 6, 2007, at 2-9. Thompson Hearing Testimony, November 12, 2007, at 99-142.

9. In a CFB plant, coal is a fuel, whereas in an IGCC plant the coal is a feedstock for a chemical process, where it is thermally converted into a gas. For an IGCC facility, this syngas

which is the fuel is then combusted in a separate gas turbine power plant, not a boiler. Jenkins Pre-Filed Testimony, August 31, 2007 at 3-5, 7, 9-10. Jenkins Hearing Testimony, November 12, 2007 at 182-184, 208-209.

10. IGCC is a power generation technology, not an emission control technology. Jenkins Pre-Filed Testimony, August 31, 2007 at 4, 7, 8, 42. Campbell Hearing Testimony, November 12, 2007. at 281, 288. Jenkins Hearing Testimony, November 12, 2007, at 187-190, 200, 208.

11. IGCC is not a technology that can be added onto or designed into the proposed CFB installation "for the control of . . . pollutant[s]." Jenkins Pre-Filed Testimony, August 31, 2007, at 7. Jenkins Hearing Testimony, November 12, 2007, at 188-190.

12. The BACT requirement is not to be used "as a means to redefine the design of the source when considering available emission control options." Draft NSR Manual at B.13. *In re Pennsauken County, New Jersey Resource Recovery Facility*, PSD Appeal No. 88-8, 1988 WL 249035 (EPA November 10, 1988). EPA's 8/30/07 Response to Comment #2a, Deseret Power's Permit No. PSD-OU-0002-04.00, attached to Jenks Pre-Filed Testimony, October 22, 2007.

13. Because of the fundamental differences between CFB and IGCC, requiring the inclusion of IGCC would effectively require SPC to redefine the design of its proposed CFB installation. Jenkins Pre-Filed Testimony, August 31, 2007, at 9-10, 42. Jenkins Hearing Testimony, November 12, 2007, at 189 –190. Campbell Pre-Filed Testimony, August 31, 2007, at 4, 8, 10-11.

14. Of the numerous states that have considered the issue of whether to include IGCC in a BACT analysis for a proposed CFB boiler, only three (Illinois, New Mexico, and Montana) did so, and Montana has since determined that IGCC not be included because it would redefine the

source. None of those states went on to conclude that IGCC was BACT. Campbell Pre-Filed Testimony, August 31, 2007, at 10-11. SPC's Summary of State Determinations re Inclusion of IGCC in BACT, attached to SPC's Pre-Hearing Brief.

15. Even if IGCC should otherwise be considered in a BACT analysis, only "available" control options are required to be included in Step 1. UAC R307-101-2(4); Draft NSR Manual B.5, B.11.

16. With respect to the SPC installation, IGCC is not an "available" technology, but is still in the developmental stage. Jenkins Pre-Filed Testimony, August 31, 2007, at 4, 16, 20-21, 24, 28, 30-31, 40-42. Jenkins Hearing Testimony, November 12, 2007, at 200-204, 209-210, 240-241, 307-308.

Conclusions of Law

1. Under the BACT definition in UAC R307-101-2(4), IGCC does not need to be included in a BACT analysis, in that it is an installation that is a different power production technology and to do so would require redefining the source. Findings of Fact 9-13.

2. Because the law does not require the inclusion of IGCC in the BACT analysis, the Executive Secretary did not err by not requiring the inclusion of IGCC.

3. In exercising any discretion the Executive Secretary had to require or not require the inclusion of IGCC in Step 1 of the BACT analysis, the Executive Secretary's decision to not require the inclusion of IGCC was reasonable.

4. Even if the Executive Secretary was otherwise required to include IGCC in the BACT analysis, the Executive Secretary did not err by not requiring consideration of IGCC in the BACT analysis because only "available" control options are required to be included in Step 1,

and, with respect to the SPC application, IGCC could not be considered an "available" technology. Findings of Fact 16.

Issue 3

Issue 3 is whether the Executive Secretary failed to provide adequate justification for not requiring Sevier Power Company to meet the most stringent oxides of nitrogen ("NOx") BACT limits proposed or required for other CFB Boilers.

On November 7, 2007, the Board upheld the actions of the Executive Secretary on Issue 3 by a vote of six in favor (Horrocks, Peterson, Samuelson, Smith, Bunker, and Elstein) and one opposed (Burwell) based on the following findings and conclusions.

Findings of Fact

1. SPC's NOI to build a power plant utilized a CFB boiler with selective non-catalytic reduction ("SNCR") with ammonia injection as a post-combustion control device for NOx control. SPC 0054-0738.

2. SPC is required to employ the "best available control technology" ("BACT") for NOx. UAC R307-401-6(1).

3. SPC submitted a BACT analysis for NOx with its NOI. SPC 0139-0145.

4. SPC's BACT analysis concluded that the proposed emission limit for NOx (0.10 lb/MMBtu based on a 24-hour basis) was equivalent to or lower than other facilities using CFB boilers with SNCR. SPC 0139-0145. Conger Pre-Filed Testimony, June 27, 2007, at 4-13. Conger Hearing Testimony, October 1, 2007, at 114-122.

5. The Executive Secretary conducted a BACT analysis and independently evaluated control technologies with potential application to SPC's proposed CFB boiler. SPC 1031-1035.

Jenks Pre-Filed Testimony, September 10, 2007, at 8-9. Jenks Hearing Testimony, October 1, 2007, at 161-180.

6. The Executive Secretary identified two technologies that were potentially applicable to the SPC project: SNCR which had been employed by SPC and Selective Catalytic Reduction ("SCR"). SPC 1031. Jenks Pre-Filed Testimony, September 10, 2007, at 8.

7. Sierra Club argued that SCR should have been more fully considered in the BACT determination for the SPC facility in that: SCR's use had been demonstrated in CFB facilities overseas, SCR has better NOx control efficiencies, the Utah Division of Air Quality ("DAQ") did not discuss SCR with vendors, and DAQ did not describe why SCR technology transfer to CFBs was infeasible. Sahu Pre-Filed Testimony, June 27, 2007, at 5-22. Sahu Hearing Testimony, October 3, 2007, at 621-655, 682-690.

8. The use of SCR on coal-fired atmospheric CFB boilers is not demonstrated as technically feasible because of issues involving the high particulate matter of the exhaust stream, the low exhaust gas temperature, as well as the chemical composition of the exhaust stream. SPC 1032. Jenks Pre-Filed Testimony, September 10, 2007, at 8-9. Jenks Hearing Testimony, October 1, 2007, at 161-180, 211. Campbell Pre-Filed Testimony, August 20, 2007, at 11-16. Campbell Hearing Testimony, October 3, 2007, at 667, 676-677. Conger Pre-Filed Testimony, June 27,2007, at 11-13. Conger Hearing Testimony, October 1, 2007, at 120. Hennenfent Pre-Filed Testimony, June 27, 2007, at 4-7. Hennenfent Hearing Testimony, October 1, 2007, at 309-314.

9. The Executive Secretary "was unable to find a single instance of an atmospheric coal-fired atmospheric CFB boiler using SCR for control of NOx." Jenks Pre-Filed Testimony,

September 10, 2007, at 8. Campbell Pre-Filed Testimony, August 20, 2007, at 12-16.

10. The CFB boilers located overseas that use SCR are not comparable as argued by Sierra Club because they are small industrial boilers which do not burn coal. Jenks Hearing Testimony, October 1, 2007, at 177-180. Hennenfent Hearing Testimony, October 1, 2007, at 312-314.

11. The Executive Secretary approved SPC's selection of SNCR as BACT for the SPC project because SNCR has been demonstrated to offer the maximum degree of reduction in reducing NOx emissions from CFB boilers. SPC 1032-1033.

12. SNCR technology has been demonstrated for use on atmospheric coal-fired CFB boilers and is BACT for the SPC project. SPC 0139-0145, 1031-1035. Jenks Pre-Filed Testimony, September 10, 2007, at 8-9. Jenks Hearing Testimony, October 1, 2007, at 161-180. Campbell Pre-Filed Testimony, August 20, 2007, at 17-20. Campbell Hearing Testimony, October 3, 2007, at 664-665, 692-693. Conger Pre-Filed Testimony, June 27, 2007, at 4-13. Conger Hearing Testimony, October 1, 2007, at 114-122, 149-150. Hennenfent Pre-Filed Testimony, June 27, 2007, at 4-7.

13. Sierra Club argued that even using SNCR, the Executive Secretary had not appropriately established NOx emission limitations for the SPC facility, more stringent numbers should have been applied based on actual emissions data from other facilities and alternative averaging periods. Sahu Pre-Filed Testimony, June 27, 2007. Sahu Hearing Testimony, October 3, 2007, at 621-655, 682-690.

14. The Executive Secretary reviewed EPA's BACT/RACT/LAER Clearinghouse, along with web searches and a review of other sources using CFB boilers with SNCR to approve the

emission rate for NOx of 0.10 lb/MMBtu based on a 24-hour basis as BACT for SPC's project. SPC 1033-1035. Jenks Pre-Filed Testimony, September 10, 2007, at 8-9. Jenks Hearing Testimony, October 1, 2007, at 161-180, 218-220.

15. Permits with different time frames are statistically comparable to SPC's proposed emission limit of 0.10 lb/MMBtu on a 24-hour basis. Jenks Pre-Filed Testimony, September 10, 2007, at 8. Jenks Hearing Testimony, October 1, 2007, at 191-195. Campbell Hearing Testimony, October 3, 2007, at 655-658.

16. The Executive Secretary did not find "any atmospheric CFB boiler with a lower emission limit expressed with the same averaging period." Jenks Pre-Filed Testimony, September 10, 2007, at 9.

17. Other facilities, including those listed in the National Parks Service comments, are distinguished from the SPC emission limits based on the type of technology, fuel used, size of facility, different permit emission time periods and, actual emissions versus permit emission limits. Jenks Hearing Testimony, October 1, 2007, at 161-180. Campbell Hearing Testimony, October 3, 2007, at 655-675.

18. The emissions limit for NOx for the SPC project, 0.10 lb/MMBtu based on a 24-hour basis, is the lowest permit limit for NOx for an atmospheric CFB boiler using SNCR and is BACT for the SPC project. SPC 0139-0145, 1031-1035; Jenks Pre-Filed Testimony, September 10, 2007, at 8-9. Jenks Hearing Testimony, October 1, 2007, at 161-180. Campbell Pre-Filed Testimony, August 20, 2007, at 17-20. Campbell Hearing Testimony, October 3, 2007, at 660-666, 691-694. Conger Pre-Filed Testimony, June 27, 2007, at 4-13. Conger Hearing Testimony, October 1, 2007, at 114-122. Hennenfent Pre-Filed Testimony, June 27, 2007, at 4-7.

Hennenfent Hearing Testimony, October 1, 2007, at 323.

Conclusions of Law

1. The Executive Secretary correctly determined that SNCR technology is BACT for the SPC project. Findings of Fact 4-12.

2. The Executive Secretary did not err and complied with state rules in establishing the emission limit for NOx (0.10 lb/MMBtu based on a 24-hour basis) as BACT in that it is equivalent to or lower than other facilities using CFB boilers with SNCR. Findings of Fact 14-18.

3. Sierra Club did not meet its burden of proving SCR was feasible and available to be considered as BACT, nor that a more stringent emission limitation was BACT.

Issue 4

Issue 4 is whether the Executive Secretary failed to consider sufficiently activated carbon injection for control of mercury emissions from the SPC facility in its MACT determination.

On November 7, 2007, the Board upheld the actions of the Executive Secretary on Issue 4 by a vote of six in favor (Horrocks, Peterson, Samuelson, Smith, Bunker,and Elstein) and one opposed (Burwell) based on the following findings and conclusions.

Findings of Fact

1. The SPC facility will emit mercury, a Hazardous Air Pollutant ("HAP"), as defined by 112(b) of the Clean Air Act. UAC R307-101-2.

2. SPC was required to obtain an approved Maximum Achievable Control Technology ("MACT") determination from the Executive Secretary regarding its mercury emissions pursuant to 40 C.F.R. § 63.43 which was incorporated into Utah's regulations at UAC R307-214-2(2).

3. 40 C.F.R. § 63.43 (d) (1) and (2) state as follows:

> The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority.
>
> Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

4. SPC conducted a case by case MACT determination which was submitted to the Executive Secretary on December 5, 2003. SPC 0007-0011.

5. The SPC MACT determination included review and comparison of existing sources of mercury emissions from CFB boilers with fabric filters, and evaluation of other control options. Conger Pre-Filed Testimony, June 27, 2007, at 17-18.

6. CFB boilers typically have high flue gas concentrations of high-carbon-content fly ash and therefore high levels of mercury capture can be accomplished in particulate emission control devices such as a baghouse (fabric filters). Conger Pre-Filed Testimony, June 27, 2007, at 16-19. Conger Hearing Testimony, October 3, 2007, at 534. Hennenfent Pre-Filed Testimony, June 27, 2007, at 9-10. Hennenfent Hearing Testimony, October 3, 2007, at 548-550, 556.

7. Sierra Club argued that activated carbon injection should have been more fully considered and applied for control of mercury and that actual mercury emissions at other coal-fired power plants are lower than SPC's emission limits. Sahu Pre-Filed Testimony, June 27, 2007, at 23-32. Sahu Pre-Filed Rebuttal Testimony, September 19, 2007, at 1-4. Sahu

Testimony, October 3, 2007, at 577-585.

8. Activated carbon injection had not been demonstrated to achieve better results than that proposed by SPC and it had not been demonstrated as available technology for the type of facility proposed by SPC. Conger Pre-Filed Testimony, June 27, 2007, at 18-19. Conger Hearing Testimony, October 3, 2007, at 534. Hennenfent Pre-Filed Testimony, June 27, 2007, at 9-10. Hennenfent Hearing Testimony, October 3, 2007, at 548-550, 556. Jenks Pre-Filed Testimony, September 10, 2007, at 10-11. Jenks Hearing Testimony, October 3, 2007, at 564-566, 568, 571. Campbell Hearing Testimony, October 3, 2007, at 599-605.

9. The use by SPC of a sorbent injection system with a dry-lime scrubber for control of NOx and other acid gases that will inject low-moisture slurry of lime into the exhaust prior to the baghouse would result in the lime particles absorbing sulfur compounds and acid gases as well as mercury emissions that are collected in the bag house, similar to an activated carbon injection system. Jenks Pre-Filed Testimony, September 10, 2007, at 10-11.

10. The MACT emission limit for mercury for SPC is 4×10^{-7} lb/MMBtu or four tenths of a pound per trillion Btu heat input. SPC 0861-0864, 2481-2493. Jenks Pre-Filed Testimony, September 10, 2007, at 10-12. Campbell Pre-Filed Testimony, August 20, 2007, at 27, 37-38.

11. The SPC mercury limitation is the lowest mercury emission limit of any coal-fired electricity utility boiler. Jenks Pre-Filed Testimony, September 10, 2007, at 10. Jenks Hearing Testimony, October 3, 2007, at 567. Campbell Pre-Filed Testimony, August 20, 2007, at 29. Campbell Hearing Testimony, October 3, 2007, at 607. Hennenfent Hearing Testimony, October 3, 2007, at 563.

12. EPA has rescinded the MACT standard for mercury and is regulating mercury

emissions from power plants under the New Source Performance Standards ("NSPS"). Conger Pre-Filed Testimony, June 27, 2007, at 14-15. 70 FR 15994 (March 29, 2005).

13. EPA's current NSPS requirements for coal-fired electric generating units for mercury include the use of fabric filters or electrostatic precipitators, wet or dry flue gas desulfurization, SCR or SNCR on bituminous units. 70 FR 28606 (May 18, 2005). Conger Pre-Filed Testimony, June 27, 2007 at 20.

14. SPC's permit application proposes to use bituminous coal, fabric filters, SNCR for NOx reduction and a dry lime scrubber which meet the technical basis that EPA used to determine Best Demonstrated Technology under NSPS. Conger Pre-Filed Testimony, June 27, 2007, at 20.

15. EPA's NSPS standard for bituminous coal is 20×10^{-6} lb/MWh. Conger Pre-Filed Testimony, June 27, 2007, at 15.

16. SPC's emissions limit for mercury in its AO is below the NSPS mercury control limit. Conger Pre-Filed Testimony, June 27, 2007, at 20.

Conclusions of Law

1. The Executive Secretary properly determined that SPC's emissions limit for mercury complied with the MACT requirements in 40 CFR § 63.43(d) and was and is the lowest in the United States. Findings of Fact 6, 9, and 11.

2. The Executive Secretary did not err in rejecting activated carbon injection for the reasons set forth in the Findings of Fact 8 and 9 above.

3. The Executive Secretary correctly determined that the MACT emission limit for mercury for SPC is 4×10^{-7} lb/MMBtu.

4. Sierra Club failed to meet its burden of proof that activated carbon injection was commercially available and could be applied to the SPC facility.

Issue 7

Issue 7 is whether the Executive Secretary failed to require sufficient analysis of the impacts of the SPC facility on visibility, soils, and vegetation.

Mr. Horrocks recused himself from discussion and voting on this issue. On November 7, 2007, the Board upheld the actions of the Executive Secretary on Issue 7 by a vote of five in favor (Peterson, Samuelson, Smith, Bunker, and Elstein) and one opposed (Burwell) based on the following findings and conclusions.

Findings of Fact

1. UAC R307-405-6(2)(a)(i)(D) states that an NOI must contain:

> An analysis of the air quality related impact of the source or modification including an analysis of the impairment to visibility, soils, and vegetation and the projected air quality impact from general commercial, residential, industrial, and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

2. SPC submitted in its NOI an analysis of the impacts to visibility, soils and vegetation. SPC 0269-0272, 0637-0682, and 0284-0287.

3. Sierra Club argued that the analysis was inadequate because of lack of visibility information for Sevier Valley, lack of analysis of pollutants other than SO2 and inadequate growth projections and information. Sahu Pre-Filed Testimony, June 27, 2007, at 33-38. Sahu Hearing Testimony, October 3, 2007, at 496-502.

4. SPC conducted and submitted, and the Executive Secretary reviewed and approved, an analysis regarding visibility by submitting a plume blight or visual impact analysis to determine

whether or not a plume emanating from the proposed SPC project would be visible inside the nearby national parks (Class I areas) that require special protection. The results of SPC's plume blight analysis showed that at five areas in Utah (Arches, Bryce, Canyonlands, Capitol Reef, and Zion National Parks) and one Class I area in Colorado (Weminuche Wilderness Area), the plume would not be visible to an observer in these Class I areas. Capital Reef is the closest (approximately 50 Kilometers) to Sevier Valley. Conger Pre-Filed Testimony, June 27, 2007, at 22-25. Conger Hearing Testimony, October 3, 2007, at 427-429. Orth Pre-Filed Testimony, September 12, 2007, at 13. Campbell Hearing Testimony, October 3, 2007, at 516, 520, 528-530.

5. The visibility impacts in the Sevier Valley (a Class II area) were not modeled since there is no regulatory (federal or state) requirement for analyses of visibility impact in Class II areas. The Executive Secretary determined that "(n)ear-field modeling for visibility is also problematic because the models are complex and the results are too unreliable for using in pre-construction permitting. There are also limitations to their applicable use in transport areas as small as the Sevier Valley." Orth Pre-Filed Testimony, September 12, 2007, at 11-12. Orth Hearing Testimony, October 3, 2007, at 443, 452-453. Conger Pre-Filed Testimony, June 27, 2007, at 22-25. Conger Hearing Testimony, October 3, 2007, at 427-429, 443. Campbell Pre-Filed Testimony, August 20, 2007, at 24-26.

6. SPC's plume blight or visual impact analysis for Class I areas served as a proxy for Class II areas because there were Class I areas that were close enough to be covered by a plume blight analysis rather than a regional haze analysis. Campbell Hearing Testimony, October 3, 2007, at 528-530.

7. SPC's AO contains two provisions for opacity monitoring, one relating to the overall facility and another specific monitoring requirement for opacity at SPC's stack which govern and are related to visibility close to SPC's facility. SPC 2490.

8. In preparing the soils and vegetation section of a PSD permit, SPC consulted EPA's Draft NSR Manual and the Natural Resource Conservation Service ("NRCS") in order to review the soil types in the area. Draft NSR Manual at D.4-5. Richins Pre-Filed Testimony, June 27, 2007, at 4-7.

9. SPC concluded that none of the soil types in the area are likely to show adverse impacts as a result of the low levels of near field emissions from the SPC power plant. The emissions from the SPC facility are mildly acidic and should be neutralized by the soils in the area near SPC's facility which are mildly to strongly alkaline. Richins Pre-Filed Testimony, June 27, 2007, at 6-7.

10. SPC also relied on the fact that "for most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary [NAAQS] will not result in harmful effects. " Draft NSR Manual at D.4-5. Because SPC's modeled emissions are below the secondary NAAQS and the agricultural areas of the Sevier Valley are almost completely excluded from the predicted impact areas of the plume, harm to vegetation is not expected. Richins Pre-Filed Testimony, June 27, 2007, at 13-15. Orth Pre-Filed Testimony, September 12, 2007, at 10. Richins Hearing Testimony, October 3, 2007, at 455-464. Jenks Hearing Testimony, October 3, 2007, at 481.

11. SPC 's review of the vegetation surrounding the SPC power plant, after consultation with NRCS, Bureau of Land Management and the United States Forest Service did not identify

species that required regulatory protection. Richins Pre-Filed Testimony, June 27, 2007, at 8-9.

12. SPC determined that while some primary crops grown in the Sevier Valley, alfalfa, wheat and barley are considered to be SO_2 sensitive, the maximum modeled SO_2 concentrations are below the threshold level at which harm to these crops is known to occur. Richins Pre-Filed Testimony, June 27, 2007, at 12-13. Jenks Pre-Filed Testimony, September 10, 2007, at 12-13.

13. SPC's emissions and modeling information was reviewed by DAQ's toxicologist who determined that additional analysis was not required. Jenks Pre-Filed Testimony, September 10, 2007, at 12-13. Jenks Hearing Testimony, October 3, 2007, at 481.

14. The Executive Secretary reviewed SPC's modeling analysis and determined that no observable changes in native vegetation or crop plants were expected to occur. Orth Pre-Filed Testimony, September 12, 2007, at 10-11.

15. The SPC growth analysis determined that the additional impacts caused by the project would be minimal. SPC 0288, 0742-0747, 1402-1409. Jenks Pre-Filed Testimony, September 10, 2007, at 12-13. Campbell Pre-Filed Testimony, August 20, 2007, at 20-22.

Conclusions of Law

1. UAC R307-405-6(2)(a)(i)(D) setting forth the requirements relating to visibility, soils, vegetation and impacts from growth for projects such as the SPC facility does not specify the extent or content of the analysis regarding the impairment to visibility, soils, vegetation and growth for the area.

2. The Executive Secretary's determination that the analysis submitted by SPC on visibility, soils, vegetation and impacts from growth was adequate and met the requirements of UAC R307-405-6(2)(a)(i)(D) was correct and reasonable.