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February 22, 2008

Heather Abrams
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Environmental Protection Division
Air Protection Branch
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Atlanta, Georgia 30354

RE: Comments on Plant Washington - Application No. 17924

Dear Ms. Abrams:

We are writing to comment on Application No. 17924, submitted by Power4Georgians, LLC for the construction and operation of Plant Washington, a coal-fired power plant in Sandersville, Georgia. For the reasons discussed below, the Georgia Environmental Protection Division ("EPD") should return the application as incomplete. In the alternative, EPD should require significant changes in the application in order to address the many problems detailed below.

These comments are submitted on behalf of the following organizations:

Altamaha Riverkeeper
Center for a Sustainable Coast
Environment Georgia
The Georgia Conservancy
Georgia Conservation Voters
Georgia Interfaith Power & Light
Georgia River Network
Micah's Mission
Mothers and Others for Clean Air
Ogeechee-Canoochee Riverkeeper
Physicians for Social Responsibility/Atlanta
Satilla Riverkeeper
Sierra Club
Turner Environmental Law Clinic at the Emory University School of Law
Upper Chattahoochee Riverkeeper

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I. THE APPLICANT FAILED TO PROPERLY ANALYZE THE BEST AVAILABLE CONTROL TECHNOLOGY.

In general, the Best Available Control Technology ("BACT") determination contained in the Application is flawed in part because the Applicant failed to follow EPD's procedures in establishing BACT. EPD has stated that the procedures laid out in 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.

The Application is incomplete and should be returned to the Applicant to cure the errors and omissions identified below. It is replete with unsupported and erroneous assertions. The BACT analyses for the pulverized coal-fired boiler ("PC Boiler") for the various pollutants fail to identify all feasible control options in Step 1, eliminate feasible control options in Step 2, fail to rank or incorrectly rank options in Step 3, eliminate feasible options using erroneous cost analyses in Step 4, and fail to select emission limits that correspond to the maximum degree of reduction that is achievable for Particulate Matter of 2.5 microns or less ("$PM_{2.5}$"), Nitrogen Oxide ("NOx"), Carbon Monoxide ("CO"), Volatile Organic Compounds ("VOC"), Sulfur Dioxide ("SO_2"), Lead ("Pb"), fluorides ("HF"), and sulfuric acid mist in Step 5.

Further, the Application is missing key components of a Prevention of Significant Deterioration ("PSD") review including an opacity BACT analysis, a Carbon Dioxide ("CO_2") BACT analysis, and a $PM_{2.5}$ BACT analysis. Finally, the Application does not contain all of the information required to support the BACT analyses, including coal quality data, an electronic copy of emission spreadsheets, continuous emission monitoring system ("CEMS") and other testing data that are relied upon to assert achievable limits, vendor guarantees for pollution control equipment, and citations to the literature that are relied upon. These defects are briefly discussed below.

A. The Application Fails To Evaluate IGCC.

The draft permit fails to consider Integrated Gasification Combined Cycle ("IGCC") coal gasification technology as part of its BACT analysis. IGCC is an available control technology (with top-of-the-line pollution control efficiencies) that the Applicant should have fully considered in the application's BACT determination for each of the PSD-regulated pollutants.

The necessity of considering IGCC as part of a BACT analysis for a PSD permit for a coal-fired power plant was raised recently during the permitting of the proposed Longleaf coal-fired facility, Permit No. 4911-099-0030-P-01-0. In that matter, an administrative law judge ruled that IGCC need not be considered as part of a BACT analysis. That ruling is currently being appealed, and the text below explains why, for legal and policy reasons, the judge's ruling was incorrect. If EPD processes this application without consideration of alternatives such as IGCC and the Longleaf's judge's ruling is reversed, the Applicant here will be adversely affected. Until the law in this area is clarified, the safer course is for EPD to return the application and request that the Applicant fully consider IGCC as an alternative.

1. Federal Law Requires A Thorough Evaluation Of IGCC As Part Of The BACT Analysis.

The Clean Air Act requires that a permit issued to a major new source of air pollution in an attainment area include an emission limit that reflects the installation of BACT for each regulated air pollutant. 42 U.S.C. §§ 7471, 7475(a)(2), 7479(3); 40 C.F.R. 51.166(j), (q), and 52.21(j). Georgia incorporates by reference the federal definition of BACT, found at 40 C.F.R. § 52.21 (b)(12).[1] BACT is defined as "an emission limitation . . . based on the maximum degree of reduction for each pollutant . . . which the [agency] . . . determines is achievable" after "taking into account energy, environmental and economic impacts and other costs." 42 U.S.C. § 7479(3); 40 C.F.R. 52.21(b)(12). Such "maximum degree of reduction" is to be achieved "through application of *production processes* or available methods, systems, and techniques, including *fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques*." *Id.*

As this definition makes clear, BACT requires a comprehensive analysis of all potentially available emission control measures, expressly including input changes (such as fuel cleaning or the use of clean fuels), process and operational changes (including innovative combustion techniques), and the use of add-on control technology. This plain reading has been confirmed a number of times by the U.S. EPA's Environmental Appeal Board ("EAB"), which has held that a permitting agency undertaking a BACT analysis must consider not only add-on pollution controls (such as scrubbers and baghouses), but also the use of clean fuels, *In re Inter-Power of New York*, 5 E.A.D. 130, 134 (EAB 1994); *In re Hawaiian Commercial & Sugar Co.*, 4 E.A.D. 95, 99 n. 7 (EAB 1992), and "inherently low-polluting process/practice that prevents emissions from being generated in the first place." *In re Knauf Fiberglass, GmBH*, 8 E.A.D. 121, 129 (EAB 1999); *see also In re Indeck-Elwood, LLC*, PSD Appeal 03-04 (EAB Sept. 27, 2006), 13 E.A.D. ___, slip op. p. 53 n. 77.[2]

The Act plainly requires consideration of IGCC in the BACT analysis. In fact, consideration of IGCC is required by two separate elements of the BACT requirement. First, it is dispositive that Congress specifically contemplated the consideration of IGCC in the BACT analysis when it amended the Clean Air Act ("CAA") to require evaluation of "innovative fuel combustion techniques." As discussed below, this language leaves no doubt whatsoever that the Act requires permitting authorities to evaluate IGCC when conducting BACT analyses. Second, as discussed below, IGCC fits squarely within a permitting authority's obligation to consider "fuel cleaning," and EPA has acknowledged IGCC as a valuable means of removing pollutants from coal prior to combustion. Moreover, because emissions of *virtually every NSR pollutant*

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[1] *See also* Georgia Rules for Air Quality Control 391-3-1-.02(7)(a)(2).

[2] Other sections of the CAA reinforce the fact that Congress understood and accepted that both add-on technology and process changes can be used to effectively control emissions. See CAA § 112(d)(2) (identifying mechanisms for reducing emission of hazardous air pollutants as including, in addition to add-on controls, "process changes, substitutions of materials or other modifications," as well as "design, equipment, work practice, or operational standards."

are significantly lower for IGCC facilities than they are for a pulverized coal plant, and because IGCC can achieve more dramatic reductions in mercury and other toxic metal emissions and do so at a much lower cost than can a traditional pulverized coal plant, taking this technology off the table before it has even been measured against the alternatives is arbitrary in the extreme.

The legislative history of the CAA confirms that as far back as *1977*, Congress intended permitting agencies to evaluate IGCC as BACT for power plants. In particular, as shown by the relevant portion of the Congressional debate excerpted below, Congress added the phrase "innovative fuel combustion technique" to clarify that gasification technology is included within BACT:

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major 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. Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.
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> Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.[3]

Nothing in either the Act or in the legislative history suggests that this reference to "innovative combustion techniques" means anything other than what it says.

[3] A&P 123 Cong. Record S9421, Clean Air Act Amendments of 1977 (June 10, 1977) (Statements of Rep. Huddleston and Rep. Muskie).

The U.S. EPA has also recognized that IGCC is a valuable method for cleaning coal and controlling air pollutants. For example, in its 2005 New Source Performance Standards rulemaking, the agency noted that SO_2 emissions can be reduced by pre-treating coal in one of two ways: "physical coal cleaning and gasification." U.S. EPA, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*, 70 Fed. Reg. 9706, 9710-11 (Feb. 28, 2005). As the U.S. EPA explained,

> Coal gasification breaks coal apart into its chemical constituents (typically a mixture of carbon monoxide, hydrogen, and other gaseous compounds) prior to combustion. The product gas is then cleaned of contaminants prior to combustion. Gasification reduces SO_2 emissions by over 99 percent.

Id. Similarly, EPA officials have repeatedly stated that IGCC technology can lead to "inherently lower emissions of nitrogen oxides, sulfur dioxides, and mercury" from coal-fired power plants. *See, 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, January 26, 2006, slide 4; and *U.S. EPA's Clean Air Gasification Initiative*, Presentation at the Platts IGCC Symposium, June 2, 2005, slide 11. As such, IGCC plainly fits within the definition of control measures that must be evaluated during the BACT process.

Consideration of IGCC as BACT is also consistent with the technology forcing nature of the CAA. As described in greater detail below, IGCC is proven and available for commercial power production applications. Forcing industry to adopt and develop this type of superior technology is the purpose of the BACT requirement. *See* S. Rep. No. 95-127 at 18 (the BACT analysis is the "most important" mechanism promoting the Clean Air Act's "philosophy of encouragement of technology development"); *Alabama Power v. Costle*, 636 F.2d 323, 372 (D.C. Cir. 1980) (noting that the PSD program is intended to be "technology forcing").

As the EAB has explained:

> A major goal of the CAA was to create a program that was technology forcing. . .
> . "The Clean Air Amendments were enacted to 'speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again.'" . . . .
> In keeping with this objective, the program Congress established was particularly aggressive in its pursuit of state-of-the-art technology at newly constructed sources. At these sources, pollution control methods could be efficiently and cost-effectively engineered into plants at the time of construction.[4]

EPA has also noted on numerous occasions that the BACT provisions of the PSD program are principally technology-forcing and are intended to foster "rapid adoption" of improvements in emissions control technology. *In re Columbia Gulf Transmission* Co., 2 E.A.D. 824, 828-29

[4] *In Re Tenn. Valley Authority*, 9 E.A.D. 357, 391 (EAB 2000) (citing *WEPCO*, 893 F.2d at 909 and H.R. Rep. No. 95-294, at 185, *reprinted in* 1977 U.S.C.C.A.N. at 1264).

(Adm'r 1989). *See also In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 127 n.26 (EAB 1997); *In re Metcalf Energy Center*, PSD Appeal 01-7, 01-8, at 15 (Aug. 10, 2001).

Similarly, a Kentucky state court recently vacated and remanded an air permit for failing to follow the forward looking nature of the BACT analysis. *Sierra Club v. Environmental and Public Protection Cabinet*, Civ. Action No. 06-CI-00640 (Franklin County Circuit Court Aug. 6, 2007). In finding the BACT analysis inadequate, the Court noted:

> The question that the [agency] must answer is not "What have other plants achieved in the past?" but rather, "What can this plant achieve for the future?" We think the answer to this question is critically important considering that the pollution-control standards the Commonwealth requires today will be in effect for the 50-year life of this power plant.

Id. at 8.

The forward looking approach established by the CAA is designed to ensure that new cleaner technologies and production methods, such as IGCC, are adopted by industry rather than languishing on the shelf. This technology-forcing goal cannot be achieved without requiring the evaluation of IGCC during the BACT analysis.

In short, both the language of the Act itself and the unequivocal expressions of Congressional intent in the legislative history indicate that the BACT analysis for any new coal-fired power plant must incorporate consideration of IGCC because it is an innovative combustion technique that will reduce emissions from the plant. Indeed, this requirement is not only consistent with, but necessary to the very core objective of PSD permitting – to bring about the rapid adoption of cleaner technologies that provide for a greater reductions in regulated emissions.[5] Thus, to conduct a BACT analysis consistent with the requirements of federal and state law, the Applicant and EPD must thoroughly evaluate IGCC as part of the Plant Washington BACT analysis.

2. Recent State Actions Require Consideration of IGCC As BACT.

In recent PSD permitting actions implementing the Federal PSD permitting program (either through a direct delegation from EPA or via approval of equivalent state rules in a state implementation plan (SIP)), several states have required consideration of IGCC in the BACT review process for new coal-fired power plants. These state decisions implementing the federal PSD program validate the plain language of the definition of BACT described above. It is noteworthy that these states determined it was entirely appropriate to require consideration of IGCC in the BACT review for a coal-fired power plant.

[5] Of course, BACT also requires consideration of other control measures – such as add-on emission controls to reduce pollutant emissions and fuel-related options (like natural gas or biomass co-firing).

Illinois

The Illinois EPA requires the evaluation of IGCC during the BACT process. This policy was first announced in March 2003, when the agency required the applicant of the proposed Indeck CFB coal-fired electric generation facility to conduct a robust analysis of IGCC as a core element of its BACT analysis. In so doing, the Illinois EPA noted:

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a 'production process' that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.
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> Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant. [6]

In an ensuing letter, the Illinois EPA then formally informed the U.S. EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations." [7]

New Mexico

The state of New Mexico has similarly required the thorough evaluation of IGCC during the BACT permitting process for a conventional coal-fired power plant proposed by Mustang Energy Corporation. In December 2002, the New Mexico Environment Department issued a letter to Mustang requiring a site-specific analysis of both the technical feasibility and availability of IGCC as well as CFB as part of the BACT analysis for the proposed facility.[8] After Mustang submitted its analysis, New Mexico found that the applicant had improperly relied on cost to find that IGCC technology is infeasible. In particular, the state responded to the applicant's analysis as follows:

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[6] Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003).
[7] Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003).
[8] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002).

Mustang concludes that neither IGCC nor CFB are technically feasible control options for the Mustang site. After careful review of the revised BACT analysis, as well as information gathered from independent sources, the Department determines that Mustang's conclusion is not supported by the evidence. Accordingly, the Department finds that Mustang has not demonstrated the technical infeasibility of IGCC and CFB. Moreover, applying the criteria in the NSR Manual, the Department determines that IGCC and CFB are technically feasible at the Mustang site, and must be evaluated in the remaining steps of the top down BACT methodology.

(a) IGCC and CFB are technically feasible at the Mustang site. A technology is considered to be technically feasible if it is commercially available and applicable to the source under consideration. *See* NSR Manual at B.17-18. A technology is commercially available if it has reached a licensing and commercial sales stage of development. *Id.* A technology is applicable if it has been specified in a permit for the same or a similar source type. *Id.* Mustang's revised BACT analysis indicates that IGCC is commercially available, and IGCC has been specified in air quality permits for coal-fired power plants. *See, e.g.,* Lima Energy Facility, 580 megawatt coal-fired power plant. Similarly, CFB is commercially available and has been specified in air quality permits for coal-fired power plants. *See, e.g.,* AES Puerto Rico 454 megawatt coal-fired power plant; Reliant Energy Seward 584 megawatt coal-fired power plant.

(b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical infeasibility. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.[9]

Montana

The Montana Board of Environmental Review found that the Montana Department of Environmental Quality must consider IGCC as an available technology in the BACT review for a coal-fired power plant, stating ". . .the Department should require applicants to consider innovative fuel combustion techniques in their BACT analysis and the Department should evaluate such techniques in its BACT determination in accordance with the top-down five-step method."[10]

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[9] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003), at p. 3.

[10] Montana Board of Environmental Review, Findings of Fact, Conclusions of Law, and Order In the Matter of the Air Quality Permit for the Roundup Power Project (Permit No, 3182-00), Case No. 2003-04 AQ (June 23, 2003) at 18-19.

Kentucky

In Kentucky, an administrative hearing officer reviewing the issuance of a PSD permit to Thoroughbred Generating Company ("TGC") for a new coal-fired power plant held that the state Environmental and Public Protection Cabinet:

> Erred as a matter of law by concluding that it lacked authority to require TGC to include IGCC and CFB in its BACT analysis. The Cabinet's reliance on the definition of "source" as referring to the PC boilers proposed by TGC is too narrow and is contrary to the PSD program's focus, which is site oriented, not equipment oriented.
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> Clearly the Cabinet had authority to require TGC to do a BACT analysis on both IGCC and CFB. This is clear from the legislative history of the amendment of the BACT definition . . .

Hearing Officer's Report and Recommended Secretary's Order, *Sierra Club et al. v. Environment & Pub. Prot. Cabinet*, File Nos. DAQ-26003-037 & DAQ-26048-037 (Environmental and Public Protection Cabinet, Commonwealth of Kentucky 2005), at 176 ¶¶ 413, 414.[11]

NESCAUM

In a letter to the Texas Commission on Environmental Quality regarding the Application of Sandy Creek Energy Associates, the Northeast States for Coordinated Air Use Management (NESCAUM), an association of the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, stated that IGCC must be considered in a BACT analysis for any new coal-fired power plant.[12]

Michigan

The Michigan Department of Environmental Quality recently announced and sought public comment on a proposal to require the evaluation of IGCC during the BACT process.[13] In so doing, the agency noted that IGCC "falls within the scope of the regulatory language," "achieves better environmental performance than conventional technologies," and "offers significant advantages . . . over other technologies."[14] In late December 2007, the agency issued

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[11] While the Secretary of the Environment and Public Protection Committee rejected the hearing officer's report and recommended order, a Kentucky court recently reversed the Secretary's decision. *Sierra Club v. Environmental and Public Protection Cabinet*, Civ. Action No. 06-CI-00640 (Franklin County Circuit Court Aug. 6, 2007). The court relied, in part, on the fact that the Secretary's BACT analysis was inadequate.

[12] Janet Pelley, *Environmental Science and Technology Online: Is EPA Blocking Clean Coal Technology,* http://pubs.acs.org/subscribe/journals/esthag/41/i01/html/010107news6.html

[13] Michigan Department of Environmental Quality, Notice of Extension of Comment Period on Consideration of Clean Coal Technology in Air Use Permitting (Sept. 28, 2007) .

[14] Michigan Department of Environmental Quality, Fact Sheet: Environmental Permitting of Coal-Fired Power Plants in Michigan (revised July 26, 2007).

its decision, concluding it is appropriate to include IGCC technology in the BACT analysis for a coal-fired power plant on a case-by-case basis.[15]

As the above examples from these other state PSD permitting agencies show, EPD can and should require the consideration of IGCC as part of the BACT process for the proposed Plant Washington.

3. IGCC Meets the Criteria for BACT for Plant Washington.

Had IGCC been included in the applicant's BACT analyses, it would have prevailed as the best available control technology. EPA and EPD require a "top-down" BACT analysis. 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.[16]

Step One: Identify All Control Technologies

IGCC technology is an available control technology now. Currently, there are around 130 gasification plants worldwide – fourteen are IGCC plants, with a capacity of 3,632 megawatts (MW) of electricity, worth nearly $8 billion, and using a variety of fuels such as oil residues, petroleum coke and coal. Currently, there are over thirty proposed coal-fired power plants in the U.S. using gasification technology.[17] These proposed plants include:

- American Electric Power Company's 629 MW Great Bend IGCC plant, Ohio;
- American Electric Power Company's 629 MW Mountaineer IGCC plant, West Virginia;
- Duke Energy's 630 MW Edwardsport IGCC plant, Indiana;
- Buffalo Energy's 1100 MW Glenrock IGCC plant, Wyoming;
- ERORA Group's 630 MW Taylorville Energy Center IGCC plant, Illinois;
- ERORA Group's 773 MW Cash Creek IGCC plant, Kentucky;
- Excelsior Energy's 1200 MW (two 600MW plants) Mesaba I & II IGCC plants, Minnesota; and
- Mississippi Power's 600MW Kemper County IGCC plant, Mississippi.

The range of U.S. IGCC proposals includes those using petroleum coke, bituminous coal, subbituminous coal, and lignite.[18]

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[15] Letter from Stephen E. Chester, Director, Michigan DEQ, to Interested Parties (December 20, 2007).
[16] NSR Manual, B.6.
[17] U.S. Department of Energy, *Tracking New Coal-Fired Power Plants*, October 10, 2007.
[18] U.S. Department of Energy, Fossil Energy Techline, *Tax Credit Programs Promote Coal-Based Power Generation Technologies*, August 14, 2006.

Step Two: Eliminate Technically Infeasible Options

As shown above, IGCC technology is a mature and available control technology. There are no physical, chemical, or engineering principles that would make IGCC technology infeasible for Plant Washington. First, recently built IGCC plants, such as the Salux 545 MW plant in Sardinia and the ISAB Energy 512 MW plant in Sicily, operate with more than 90% availability,[19] using more than one gasification train. The demonstrated availability of these plants is on par with the availability of pulverized coal-fired power plants. Major vendors of IGCC plants such as GE, Shell and ConocoPhillips will warrant that new IGCC plants will achieve greater than 90% availability with a spare gasifier. Rickard Payonk, plant manager at the Wabash gasification plant, which has been operating for more than ten years, summed up the feasibility of IGCC, stating "coal gasification power plants are 'absolutely' reliable and can be scaled up in size," and critics of IGCC are using "old data" about the technology's reliability.[20]

Additionally, the permit Applicant's plans to use PRB and Illinois #6 coal to fuel Plant Washington poses no barrier to using IGCC technology. In a June 2006 workshop on gasification technologies, Phil Amick, Chairman for the Gasification Technologies Council, called reports that gasification doesn't work with PRB coal a "myth."[21]

Step Three: Rank Remaining Control Technologies By Control Effectiveness

Had the Applicant included IGCC in the BACT analysis, they would have concluded that IGCC is far superior in controlling emissions of NO_X, SO_2, and several other harmful pollutants. Table 1 below shows the pollutant emission rates for three recently proposed IGCC plants. When compared to the proposed emission rates from Plant Washington, IGCC technology is shown to control emissions significantly better than the supercritical technology proposed.

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[19] Harry Jaeger, Gasification & IGCC Forum, http://gasification-igcc.blogspot.com/2006/10/hell-bent-on-going-nowhere-october.html.

[20] Bobby Carmichael, *Tech Could Reduce Coal Facilities' Emissions*, USA Today, December 26, 2007.

[21] Phil Amick, Gasification Technologies Council, *Experience with Gasification of Low Rank Coals*, June 28, 2006, at 5.

Table 1: Comparison of Emission Rates from Plant Washington with proposed IGCC plants.

Facility	*Technology*	*NO_x* (lb/MMBtu)	*SO_2* (lb/MMBtu)	*PM* (lb/MMBtu)	*H_2SO_4* (lb/MMBtu)	*CO* (lb/MMBtu)	*VOC* (lb/MMBtu)
Plant Washington	**Supercritical PC**	**0.05 (annual ave)**	**0.09 (12 month rolling ave); 0.12 (3-hr ave) (calculated from 996 lb/hr/ heat rate of 8300 MMBtu/hr.)**	**0.015 (filtera ble)**	**0.005 (3-hr ave)**	**0.15 (30 day ave) 0.30 (1-hr ave)**	**0.0034 (3-hr ave)**
Taylorville Energy Center	IGCC	0.0246 (24-hr ave)	0.0117 (3-hr ave)	0.0063 (filterab le) (3-hr ave)	0.0026 (3-hr ave)	0.036 (24-hr ave)	0.006 (24-hr ave)
Erora Cash Creek	IGCC	0.0246 (24-hr ave)	0.0117 (3-hr ave)	0.0063 (filterab le) (3-hr ave)	0.0026 (3-hr ave)	0.036 (24-hr ave)	0.006 (24-hr ave)
Mesaba I & II	IGCC	0.057	0.025	0.009	--	0.0345	0.0032

Recent studies, which estimated emission rates from IGCC plants by examining literature reviews, including recent air permits, contracts with IGCC technology suppliers, and power generation modeling software, concluded that IGCC was clearly a better choice to control SO_2, NO_X, and other dangerous pollutants such as CO, PM and VOCs, emissions than pulverized coal technology. *See* Table 2, below.[22]

[22] *See* U.S. EPA., *Environmental Footprints and Costs,* Table ES-2 at ES-8. We note that the permit limits used by EPA to generate this table are already outdated, but the information is still useful for purposes of comparison.

Exhibit ES-2, Environmental Impact Comparison

	Bituminous Coal				Subbituminous Coal			
Environmental Impact lb/MWh	IGCC Slurry Feed Gasifier	Sub-Critical PC	Super-critical PC	Ultra Super-critical PC	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	0.326	0.543	0.500	0.450
SO_2	0.311	0.757	0.709	0.654	0.089	0.589	0.541	0.488
CO	0.217	0.880	0.824	0.757	0.222	0.906	0.832	0.750
Particulate Matter[1]	0.051	0.106	0.099	0.088	0.052	0.109	0.100	0.090
Volatile Organic Compounds (VOC)	0.012	0.021	0.020	0.018	0.013	0.025	0.023	0.020
Solid Waste[3]	65	176	165	155	45	73	67	60
Raw Water Use	4,960	9,260	8,640	7,750	5,010	9,520	8,830	7,870
SO_2 Removal Basis, %	99	98	98	98	97.5	87[4]	87[4]	87[4]
NO_X Removal Basis[2]	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu

Step Four: Evaluate cost and collateral environmental effects and document results

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.
>
> 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.[23]

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[23] NSR Manual, B.8-B.9 (emphasis added).

Applying this analysis confirms that IGCC is a superior alternative to conventional PC plants.

a. Energy Impacts

As shown in the table below,[24] IGCC technology is more efficient that the supercritical PC technology proposed for Plant Washington.

Exhibit ES-1, Generation Performance Comparison

	Bituminous Coal				Subbituminous Coal			
Performance	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Net Thermal Efficiency, % (HHV)	41.8	35.9	38.3	42.7	40.0	34.8	37.9	41.9
Net Heat Rate, Btu/kWh (HHV)	8,167	9,500	8,900	8,000	8,520	9,800	9,000	8,146
Gross Power, MW	564	540	540	543	575	541	541	543
Internal Power, MW	64	40	40	43	75	41	41	43
Fuel Required, lb/h	349,744	407,143	381,418	342,863	484,089	556,818	517045	460,227
Net Power, MW	500	500	500	500	500	500	500	500

However, the efficiency of IGCC technology is expected to rise in the near future. Mitsubishi expects IGCC plant efficiency using its newly-developed gasification technology to be 43%.[25] Also, as advanced technologies for air separation and oxygen production, higher temperature gas cleaning methods, advanced gas turbines, and fuel cells are developed, thermal efficiency using IGCC technology could rise to 50% – 60%.[26]

b. Environmental Impacts

IGCC plants have a number of advantages over PC plants when evaluating the environmental impacts of a proposed plant. First, studies suggest that IGCC can capture and sequester CO_2 at significantly lower costs than PC technology.[27] Additionally, IGCC technology is environmentally superior to PC technology for minimizing emissions of mercury and other toxic chemicals. According to the U.S. Department of Energy, a significant portion of mercury appears to be removed within the IGCC process, decreasing the amount contained in the stack gas; the mercury that remains can also be removed at about one-tenth the cost of PC based mercury control.[28]

Also, the waste leaving an IGCC plant is vitrified, thereby potentially reducing some of the solid waste disposal issues associated with coal combustion. Indeed, IGCC plants produce

[24] U.S. EPA, *Environmental Footprints and Costs*, p. ES-7.
[25] Mitsubushi, *PRB Coal Gasification Test Results with Air Blown IGCC*, October 2006, at 27.
[26] *See* U.S. EPA., *Environmental Footprints and Costs,* at ES-2.
[27] *Id.*
[28] U.S. Department of Energy, *Major Environmental Aspects of Gasification-Based Power Generation Technologies*, *Final Report*, December 2002, at ES-5.

30-50% less solid waste than PC plants.[29] Lastly, an IGCC plant uses approximately one-half to two-thirds less water than a pulverized coal plant,[30] a significant advantage in Georgia.

c. Economic Impacts

While it is true that construction of an IGCC plant can be more expensive, as noted in the January 31, 2007 National Park Service comments on the White Pine Energy Station draft permit, energy industry leaders expect the IGCC cost "penalty" to be reduced to no more than 10% once General Electric acquires the capability to build a complete 600 MW IGCC facility.[31] If a traditional PC plant was required to achieve the same emissions levels as an IGCC plant, IGCC would achieve cost parity.[32] Additionally, as additional emission restrictions are imposed on electricity generators, such as requirements for carbon capture and sequestration, IGCC is expected to become the lowest cost technology.[33] According to the EPA, there are only small differences between the operating costs between the two types of technologies.[34]

Additionally, obtaining financing for IGCC plants is becoming more attractive. In January 2007, GE Energy Financial Services, a unit of General Electric, recently announced that it is acquiring a 20% equity interest in The ERORA Group LLC's 630 MW Cash Creek IGCC facility in Kentucky, joining the New York investment firm D.E. Shaw group, which committed up to $500 million in October 2006 to build the Cash Creek plant.[35] In July 2006, independent power producer Tenaska, Inc. purchased a 50% development-stage interest in the proposed Taylorville Energy Center.[36] Furthermore, Mitsubishi has provided NRG Energy, Inc. with financial guarantees that its IGCC process proposed for NRG's IGCC plant in New York will work.[37]

Step Five: Select BACT

IGCC is clearly superior to the proposed BACT controls for Plant Washington. IGCC technology is mature and available, as evidenced by the large number of proposed IGCC plants across the country and growing investor interest. While constructing an IGCC plant is more expensive than constructing a PC plant, the cost gap is quickly narrowing, and IGCC is expected to become the lowest cost technology when capturing and sequestering CO_2 is factored into the equation. Additionally, there is little difference in operating costs for both types of plants.

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[29] *Id.* at 1-28.
[30] *Id.* at 2-61.
[31] NPS White Pine comments on draft air permit.
[32] Energy Center of Wisconsin, *IGCC Engineering and Permitting Issues Summary*, April 2006, at 4.
[33] *Id.*
[34] U.S. EPA, *Environmental Footprints and Costs,* at ES-5.
[35] GE Press Release, *GE Unit Makes First Investment in Infrastructure Project Using Gasification Technology*, Jan. 23, 2007.
[36] Tenasksa Press Release, *Tenaska Purchases 50% Development Interest in Illinois Clean Coal Generation Plant,* July 11, 2006.
[37] Elizabeth Souder- DallasNews.com, *NRG Wants a Deal with Texas*, February 15, 2007.

When compared with emission rates from recent permit applications, IGCC technology is shown to control emissions significantly better than the supercritical PC technology proposed for Plant Washington. Environmentally, IGCC is clearly a better choice, producing less mercury, among other emissions, and solid waste, and using less water. The overall superiority of IGCC technology in plant efficiency, controlling SO_2, NO_X, and PM, as well as other toxic chemicals together with other environmental benefits clearly justifies the selection of IGCC technology over the supercritical PC technology proposed for Plant Washington.

B. There is No BACT Determination for CO_2.

The application is flawed because it does not contain a BACT analysis for CO_2. The necessity of including a BACT analysis for CO_2 in an application for a PSD permit for a coal-fired power plant was raised recently during the permitting of the proposed Longleaf coal-fired facility, Permit No. 4911-099-0030-P-01-0. In that matter, an administrative law judge ruled that no such BACT analysis is required. That ruling is currently being appealed, and the text below explains why, for legal and policy reasons, the judge's ruling was incorrect. If EPD processes this application without requiring a BACT analysis for CO_2 and the Longleaf's judge's ruling is reversed, the applicant here will be adversely affected. Until the law in this area is clarified, the safer course is for EPD to return the application and request that the applicant include a BACT analysis for CO_2.

There is no doubt that this planned facility would emit a significant amount of CO_2. As the Supreme Court noted this term, "[a] well-documented rise in global temperatures has coincided with a significant increase in the concentration of carbon dioxide in the atmosphere. Respected scientists believe the two trends are related." Massachusetts v. EPA, 127 S. Ct. 1438, 1446 (2007).

CO_2 is a regulated NSR pollutant because it is a "pollutant that otherwise is subject to regulation under the Act." 40 C.F.R. § 52.21(b)(50)(iv). This language comes straight out of the statutory definition of BACT in the Clean Air Act: "The term 'best available control technology' means an emission limitation based on the maximum degree of reduction of each *pollutant subject to regulation under this [Act]* . . . ." 42 U.S.C. § 7479(3) (emphasis added). Below, Citizens parse through each phrase of this clause to demonstrate that CO_2 requires a BACT determination.

First, the clause applies to a "pollutant." The Supreme Court has recently held that CO_2 is a "pollutant" under the Act. Section 302(g) of the Clean Air Act defines "air pollutant" expansively to include "*any* physical, chemical, biological, radioactive . . . substance or matter which is emitted into or otherwise enters into the ambient air." 42 U.S.C. § 7602(g) (emphasis added).

> The Clean Air Act's sweeping definition of "air pollutant" includes "*any* air pollution agent or combination of such agents, including *any* physical, chemical . . . substance or matter which is emitted into or otherwise enters the ambient air . . . ." §7602(g) (emphasis added). On its face, the definition embraces all airborne compounds of whatever stripe,

> and underscores that intent through the repeated use of the word "any." **Carbon dioxide**, methane, nitrous oxide, and hydrofluorocarbons are without a doubt "physical [and] chemical . . . substance[s] which [are] emitted into . . . the ambient air." The statute is unambiguous.

Massachusetts, 127 S.Ct. at 1460 (italics in original; bold added).

Next, the key phrase in the clause is "subject to." "Subject to" means "governed or affected by." The Ninth Circuit recently reached this conclusion after an extensive case law review:

> In *Northwest Forest Resource Council v. Glickman*, 82 F.3d 825 (9th Cir. 1996) (as amended), we considered the definition and scope of the words "subject to section 318" in § 2001(k)(1) of the 1995 Rescissions Act, Pub. L. 104-19, 109 Stat. 194 (1995). We concluded, inter alia, that the phrase "subject to" means "governed or affected by." *Nw. Forest Res. Council*, 82 F.3d at 833; *see also U.S. ex rel. Totten v. Bombardier Corp.*, 351 U.S. App. D.C. 30, 286 F.3d 542, 547 (D.C. Cir. 2002) ("[A]n entity is 'subject to' a particular legal regime when it is regulated by, or made answerable under, that regime."); *Texaco Inc. v. Duhe*, 274 F.3d 911, 918-19 (5th Cir. 2001) (holding that natural gas became "'subject to' an existing contract" within the meaning of the Natural Gas Policy Act when it was "governed by" terms of that contract); *Michelin Tires (Canada) Ltd. v. First Nat'l Bank of Boston*, 666 F.2d 673, 677 (1st Cir. 1981) ("The words 'subject to,' used in their ordinary sense, mean 'subordinate to,' 'subservient to,' or 'limited by.'"); *Burgess Constr. Co. v. M. Morrin & Son Co.*, 526 F.2d 108, 113 (10th Cir. 1975) ("The words 'subject to' usually indicate a condition to one party's duty of performance and not a promise by the other."). And we concluded in *Northwest Forest Resource Council* that a contrary conclusion would make mere surplusage of the provision. *See* 82 F.3d at 834; *see also id.* ("[A] statute must be interpreted to give significance to all of its parts.").

Portland GE Co. v. Bonneville Power, 2007 U.S. App. LEXIS 10342 *51-52 (9th Cir. May 3, 2007).

The next key clause is "regulation under this Act." The term "regulation" means: "a regulating principle; a precept." *See* Black's Law Dictionary 1158 (5th ed. 1978):

> **Regulation.** The act of regulating: a rule or order prescribed for management or government: *a regulating principle: a precept.* Rule or order prescribed by superior or competent authority relating to action of those under its control. Regulation is rule or order having force of law issued by executive authority of government.

Id. (emphasis added) (citing *State ex rel. Villines v. Freeman*, 370 P.2d 307, 309 (Okla. 1962)). In the context of the Clean Air Act, the term "regulation" does not, as Longleaf implies but does not explicitly state, mean "controlled." The concept of "controlling" air pollutants is embodied in the notion of "emission limitation" or "emission standard." These terms are defined in 42 U.S.C. § 7479(3) as requirements that limit "the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." 42 U.S.C. § 7602(k). Accordingly, had Congress intended to impose the BACT requirement only on those pollutants that were subject to a provision limiting the quantity, rate, or concentration of emissions, it could have used the defined term "emission limitation" or "emission standard." Congress did not make that choice of language, however, opting instead for the broader term "regulation." Accordingly, any interpretation of the phrase "subject to regulation" must take into account this choice of language.

Putting these concepts together, CO_2 must be considered a "regulated NSR pollutant" if it is a pollutant recognized under the Act that is "governed or affected by" a "regulating principle or precept" derived from the Act. CO_2 meets this test for three reasons. First, CO_2 is subject to regulation under Section 821 of the Clean Air Act Amendments of 1990. This section directed EPA to promulgate regulations to require certain sources, including coal-fired power plants, to monitor CO_2 emissions and report monitoring data to EPA. Section 821 provides as follows:

> (a) Monitoring. The Administrator of the Environmental Protection Agency shall promulgate regulations within 18 months after the enactment of the Clean Air Act Amendments of 1990 to require that all affected sources subject to title V of the Clean Air Act shall also monitor carbon dioxide emissions according to the same timetable as in section 511(b) and (c). The regulations shall require that such data be reported to the Administrator. The provisions of section 511(e) of title V of the Clean Air Act shall apply for purposes of this section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in section 511.
>
> (b) Public availability of carbon dioxide information. For each unit required to monitor and provide carbon dioxide data under subsection (a), the Administrator shall compute the unit's aggregate annual total carbon dioxide emissions, incorporate such data into a computer data base, and make such aggregate annual data available to the public.

In 1993, EPA promulgated the regulations mandated by Section 821, which are set forth at 40 C.F.R. Part 75. The regulations generally require monitoring of CO_2 emissions through the installation, certification, operation and maintenance of a continuous emission monitoring system or an alternative method (40 C.F.R. §§ 75.1(b), 75.10(a)(3)); preparation and maintenance of a monitoring plan (40 C.F.R. § 75.33); maintenance of certain records (40 C.F.R. § 75.57); and reporting of certain information to EPA, including electronic quarterly reports of CO_2 emissions data (40 C.F.R. §§ 75.60 - 64). 40 C.F.R. § 75.5 prohibits operation of an affected source in the absence of compliance with the substantive requirements of Part 75 and provides that a violation of any requirement of Part 75 is a violation of the Clean Air Act.

Second, CO_2 is subject to regulation pursuant to the landfill emission regulations at 40 C.F.R. Part 60 Subparts CC and WWW. Under these regulations, EPA defines emissions such as "municipal solid waste landfill emissions" or "MSW landfill emissions" as "gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste." 40 CFR § 60.751. The pollutant regulated by these standards, "MSW landfill emissions, or LFG, is composed of methane, CO_2, and NMOC." Air Emissions from Municipal Solid Waste Landfills – Background Information for Final Standards and

Guidelines, EPA-453/R-94-021, December 1995.[38] Municipal solid waste (MSW) landfills in some categories are required to monitor their emissions, and on the basis of that monitoring, to install a control and collection system. 40 C.F.R. § 60.752(b). "For most NSPS, emission reductions and costs are expressed in annual terms. In the case of the NSPS and EG for landfills, the final regulations require controls at a given landfill only after the increasing NMOC [nonmethane organic compounds] emission rate reaches the level of the regulatory cutoff. The controls are applied when the emissions exceed the threshold, and they must remain in place until the emissions drop below the cutoff." 61 Fed. Reg. 9905, 9908 (March 12, 1996). MSW landfills with a capacity of 2.5 million cubic meters are required to calculate emission rates for nonmethane organic carbon. 40 C.F.R § 60.752(b). For some landfills, the NMOC emission rates are calculated using data collected through sampling. 40 C.F.R § 60.754(a)(3),(4). Landfills with a calculated emission rate of greater than 50 megagrams per year of NMOC are required to install collection and control systems. 40 C.F.R § 60.754(b)(2). For landfill gases then, including CO_2, monitoring regulations are thus directly tied to emission limitations.

Third, the Georgia SIP also regulates CO_2. The SIP, which EPA approved pursuant to 42 U.S.C. § 7410 of the Act, provides that:

> No person owning, leasing or controlling the operation of any *air contaminant* sources shall willfully, negligently or through failure to provide necessary equipment or facilities or to take necessary precautions, cause, permit, or allow the emission from said *air contamination* source or sources of such quantities of *air contaminants* as will cause, or tend to cause, by themselves or in conjunction with other *air contaminants* a condition of *air pollution* on quantities or characteristics or of a duration which is injurious or which unreasonably interferes with the enjoyment of life or use of property in such area of the State as is affected thereby. Complying with any of the other sections of these rules and regulations of any subdivisions thereof, shall in no way exempt a person from this provision.

Georgia SIP, 391-3-1-.02(2)(a)(1) (emphasis added).

> The Georgia SIP defines the terms "air contaminant" and "air pollution" as follows:
> (c) "Air Contaminant" means solid or liquid particulate matter, dust, fumes, gas, mist, smoke, or vapor, or any matter or substance either physical, chemical, biological, or radioactive (including source material, special nuclear material, and by-product material); or any combination of any of the above.
>
> (d) "Air Pollution" means the presence in the outdoor atmosphere of one or more air contaminants.

Georgia SIP, 391-3-1-.01(2)(c) and (d).

From these definitions, the scope of the airborne substances governed or affected by the Georgia SIP could hardly be broader. "Air contaminants" include any gas. Thus, for the

[38] available at http://www.epa.gov/ttn/atw/landfill/landflpg.html.

purposes of the Georgia SIP, "air pollution" means the presence in the atmosphere of any gas. Thus, the Georgia SIP, a regulation in effect under the Act, covers any source that emits a gas in "such quantities . . . as will cause, or tend to cause, by themselves or in conjunction with other air contaminants a condition of air pollution on quantities or characteristics or of a duration which is injurious or which unreasonably interferes with the enjoyment of life or use of property in such area of the State as is affected thereby."

That CO_2 is a gas whose presence in significant quantities will affect areas of the state of Georgia is beyond dispute. As the Supreme Court pointed out in *Massachusetts*, the White House "sought assistance in identifying the areas in the science of climate change where there are the greatest certainties and uncertainties from the National Research Council." *Massachusetts*, 127 S. Ct. at 1449 (internal quotations omitted). The Council's report, which the Court said EPA found to be an "objective and independent assessment of the relevant science," *Id.* at 1455, identified a number of harms associated with climate change including an "accelerated rate of rise of sea levels during the 20th century relative to the past few thousand years." *Id.* at 1456. According to EPA, coastal areas of Georgia would be threatened by even a sea level rise of 1.5 meters. U.S. EPA Global Warming Report, Sea Level Rise.[39]

As both a matter of law, and of public policy, it is essential that EPD require the control of CO_2 emissions. Several reports authoritatively document the adverse environmental and socio-economic impacts of global warming at local, regional, national and global scales, and the primary role of the burning of fossil fuels, including coal, in causing global warming. The evidence conclusively shows that greenhouse gases, including CO_2, endanger public health, welfare, and the environment.

Many researchers have highlighted the severity of the threats posed by global warming. A recent study found that from 2000 to 2006, the average emissions growth rate was 3.3% per year, compared to 1.3% per year during the 1990s.[40] The study estimates that global warming is happening faster than expected, and attributes this to recent growth in the world economy, increasing carbon intensity, and decreasing efficiency in carbon sinks on land and in oceans.[41] This evidence suggests that even the estimates of the Intergovernmental Panel on Climate Change are too conservative, and that the threat of global warming may be even more imminent than originally anticipated.

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[39] See http://yosemite.epa.gov/OAR/globalwarming.nsf/content/ResourceCenterPublications SLRMapsIndex.html. To view color maps of impact on Georgia's coastline, visit http://yosemite.epa.gov/OAR/globalwarming.nsf/content/ResourceCenterPublicationsSLRMapsSouthAtlantic.html

[40] Canadell, J.G., *et al.*, *Contributions to Accelerating Atmospheric CO_2 Growth from Economic Activity, Carbon Intensity, and Efficiency of Natural Sinks*, Proceedings of the National Academy of Sciences, October 25, 2007.

[41] *Id.*

The World Health Organization reported in 2005 that, over the past 30 years, global warming has contributed to 150,000 deaths annually.[42] EPA has already recognized this and other potentially adverse effects of climate change on public health:

> Throughout the world, the prevalence of some diseases and other threats to human health depend largely on local climate. Extreme temperatures can directly lead to loss of life, while climate-related disturbances in ecological systems, such as changes in the range of infective parasites, can indirectly impact the incidence of serious infectious diseases. In addition, warm temperatures can increase air and water pollution, which in turn harm human health.[43]

One threat identified by EPA is fatalities due to extreme temperatures. Indeed, increased heat waves lead to heart failure and other heat-related deaths.

Global warming also exacerbates the problem of ground-level ozone ("smog"), intensifying the public health dangers associated with air quality violations. Breathing ozone can trigger a variety of health problems, including chest pain, coughing, throat irritation, and congestion, and repeated exposure can lead to bronchitis, emphysema, asthma, and permanent scarring of lung tissue.[44] In addition, global warming will result in increased surface water evaporation, which in turn could lead to more wildfires and increased dust from dry soil, both of which generate particulate matter emissions. Particulate matter triggers a host of health problems, including aggravated asthma, development of chronic bronchitis, irregular heartbeat, nonfatal heart attacks, and premature death in people with heart or lung disease.[45] Thus, for the health and welfare of the people of Georgia and the United States, EPD must require controls on CO_2 emissions.

C. The BACT Analysis For NOx Is Fundamentally Flawed.

The Application proposes a NOx limit of 0.05 lb/MMBtu on an annual average as BACT, based on levels set in other permits and achieved with low NOx burners and overfire air. This determination is unsupported, contrary to the definition of BACT, and erroneous.

First, the Application in Step 1 evaluates only the broad class of air staging referred to as overfire air ("OFA"). Ap., 4-28. There are several different types of overfire air which vary in NOx control ability including close-coupled OFA, separated OFA, and both close-coupled and separated OFA. The latter has the highest NOx control efficiency. The Application should be revised to list and evaluate each of these. Both close-coupled and separated OFA, widely used on coal-fired boilers, should be selected as BACT.

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[42] Jonathan A. Patz, *et al.*, *Impact of Regional Climate Change on Human Health*, Nature, 438, 310-317, November 17, 2005, *available at* http://www.nature.com/nature/journal/v438/n7066/full/nature04188.html.

[43] EPA, *Climate Change, Health and Environmental Effects*, December 20, 2007. *See also*, Centers for Disease Control, *CDC Policy on Climate Change and Public Health.*

[44] EPA, Ground-Level Ozone: Health and Environment, March 6, 2007.

[45] EPA, Particulate Matter: Health and Environment, January 17, 2008.

Second, BACT is an emission limit based on the maximum degree of reduction that is achievable. With respect to NOx BACT, the application is incomplete and otherwise erroneous. The Application does not contain a Step 3 ranking table. Without it, it is impossible to understand how the proposed NOx limit was derived, although there is information in the application to suggest that the NOx limit was not derived through a case-by-case analysis, as required by the definition of BACT. In Section 9.0 of the application, the applicant states in Form 3.00 that the inlet stream to the air pollution control device will be 41,500 pounds per hour. Form 3.00 also states that the control efficiency of the SCR will be 90%, yet the form also states that the exit stream from the APCD will be 415 pounds per hour. Thus, either the control efficiency for the SCR should have been stated as 99%, or the inlet stream to the APCD should have been stated as 4,150 pounds per hour, not 41,500.

The stated SCR inlet, 41,500 lb/hr, corresponds to 5 lb/MMBtu and is clearly wrong. The application does not state where the applicant obtained the inlet stream value, but this number is over 16 times higher than the inflated value for the inlet stream used in the Longleaf matter (.3 lb/MMBtu). The application should be returned so that the applicant can state how it derived the inlet concentration number and why that value is reflective of the maximum achievable level of reduction from the in-boiler control devices, i.e., the low NOx burners and overfire air. The applicant should then be required to apply a control efficiency percentage to the inlet stream value in order to derive an appropriate exit stream number. Our research indicates that the product of this analysis would yield a NOx emission rate of 0.015 lb/MMBtu based on a 30-day average.

Third, the determination is also erroneous because it fails to consider existing facilities firing similar coals that are achieving much lower NOx emissions rates. The Application should be supplemented with NOx CEMS data, including that for Parish Units 5, 6, 7 and 8 and Pleasant Prairie Units 1 and 2, all of which are currently achieving lower NOx emissions than proposed here as BACT. The BACT limit should be based on the NOx levels on a 24-hour, 30-day, and annual average basis being achieved at these and other similar facilities, not historically permitted levels.

Fourth, the Application cites various NOx levels that are alleged to be achieved by 63 coal-fired boilers and by MidAmerican Energy Company. The Application should be supplemented to include the cited data in an Excel spreadsheet that identifies each subject unit and explains why the average of this random collection of facilities that include poorly performing units should be used to determine the "best" under the BACT test.

Finally, the NOx BACT analysis should explain why lower NOx limits including those for Trimble Unit 2, Newmont, Desert Rock, and Toquop do not establish BACT or at least a starting point for establishing the NOx BACT emission limit for this permit. The Application should be amended to explain based on physical, chemical and engineering principals which these lower permitted limits and lower measured limits do not establish BACT in this case.

D. The BACT Analysis For CO Is Fundamentally Flawed.

The Application proposes a CO limit of 0.15 lb/MMBtu on a 30-day average and 0.30 lb/MMBtu on a 1 hour average. Ap., p. 4-4. This determination is not BACT.

First, this determination is based solely on listings from the RBLC. Other important sources of data, such as stack tests, CEMS data, and vendor information were not consulted. There are numerous stack tests and reams of CEMS data that demonstrate much lower CO limits are being met on a routine basis. The Application is incomplete because it has failed to consult this existing data.

Second, the RBLC listings that were relied on are based on the AP-42 emission factor for CO. The Introduction to AP-42 is clear that its emission factors are not appropriate for regulatory purposes such as establishing BACT because they are averages. Half the boiler population would be expected to have lower and half higher CO emissions. This is contrary to the definition of BACT.

Third, BACT is to be met using generic "combustion controls." The Application does not define what constitutes good combustion control, which includes a wide range of options, such as combustion optimization software, a high efficiency boiler (and a limit set in terms of lb/MW-hr to assure the efficiency target is met day in and day out), oxy combustion, various types of air staging, various types of low NOx burners, etc.

Fourth, the Application erroneously rejects lower CO limits, arguing they do not apply in this case because NOx emissions are lower here, justifying a higher CO limit. Ap., p. 4-40. This approach is simply incorrect. Some of the facilities with lower CO limits also have *lower* NOx limits, e.g., Toquop, Desert Rock, Trimble. Further, whether boiler combustion NOx is higher or lower is irrelevant because an SCR will be used downstream of the boiler. Any small increase in NOx from tightening the CO limit could be readily offset by a slight increase in the efficiency of the SCR. Further, BACT determinations are made on a pollutant by pollutant basis and should not constrain the determination for one pollutant by arguing adverse impacts to another. Finally, the subject PC boiler is a supercritical boiler which will achieve much lower CO limits than those tabulated from the RBLC. The Application has failed to consider the higher efficiency of the type of boiler it has selected in setting not only the CO limit, but also all other limits.

Finally, the CO BACT analysis does not contain any Step 3 ranking or disclose the control efficiency of the selected control option.

E. The BACT Analysis For SO_2 Is Fundamentally Flawed.

The Application proposes an SO2 limit of 0.09 lb/MMBtu based on a 12-month rolling average and 996 lb/hr (0.12 lb/MMBtu) based on a 3-hour average. These limits do not satisfy BACT for SO_2. The BACT analysis for SO_2 contains many errors and omissions, requiring that the Application be rejected.

Step 1 fails to include all feasible control options. Feasible combinations of control options, such a dry plus wet scrubber were not considered. Further, effective individual control options, such as ECO and ReACT were not considered.

Step 3 eliminates clean fuel, 100% PRB, based on an incorrect cost analysis. Ap., p. 4-55. Average and incremental cost effectiveness are used to evaluate adverse economic impacts. The cost analysis in the Application does not correctly calculate either average or incremental cost. Incremental cost is the ratio of the difference in annualized cost of two *control options* (not fuel cost, only a tiny part of the cost) to the difference in the emission rates of the control options. The analysis excludes the cost of the scrubber, thus slanting the result. The cost of a scrubber to remove 97.5% of the sulfur from a PRB coal is substantially lower than the cost of a scrubber to remove 97.5% of the sulfur from the much higher sulfur blend. When the cost of the control option itself is used, the incremental cost effectiveness is substantially lower than claimed in the Application. Further, the Application fails to support its contention that even its erroneously high cost effectiveness value of $10,460/ton is not cost effective in this case.

Step 4 concludes that BACT is satisfied by assuming 97.5% SO_2 removal from typical average design sulfur content (0.09 lb/MMBtu annual average) and worst-case (996 lb/hr 3-hr average) 50/50 blend coal using a wet scrubber. Ap., pp. 4-56 to 4-57. The Application is incomplete because it does not contain sufficient information to support this selection.

First, the Application does not present the design basis coal quality so it is not possible to verify the stated but otherwise unsupported emission limits. The proposed emission limits suggest that average sulfur content is 3.6 lb/MMBtu (0.09/0.025) and maximum sulfur content is 4.8 lb/MMBtu (996/8300/0.025). These high values suggest that the Application has not properly considered clean fuels in the BACT analysis. The Application should be amended to disclose the full range of coal qualities that will be used at the facility.

Second, the Application asserts that 97.5% is the highest SO_2 removal efficiency that can be expected on a consistent basis, based on CEMS data on USEPA's Clean Air Markets website. Ap., p. 4-56. This claim is incorrect. The Clean Air Markets website does not report inlet SO_2 data so it is not possible to calculate SO_2 removal efficiency based on this data. The Applicant should be required to support this assertion by identifying the specific facilities that were included in its analysis and by producing the supporting CEMS and other data. Numerous facilities have achieved higher SO_2 removal efficiencies on a consistent basis and vendors routinely guarantee 98-99% SO_2 removal efficiencies. The Applicant should collect and evaluate vendor guarantees, technical literature, stack tests, performance tests and CEMS data on operating U.S. and foreign facilities. If the Applicant persists in advocating 97.5% SO_2, control, the Applicant should be required to obtain testimonials from the major scrubber vendors, including Alstom, Babcock, Black & Veatch (Chiyoda), Marsulex, and B&W, among others to support any claim that only 97.5% SO_2 control is achievable on a consistent basis.

Third, the Application only evaluates three generic classes of scrubbers: wet, dry, and circulating fluidized bed. The wet class contains a large number of distinguishable scrubbing technologies with varying attributes, including space, energy demand, and performance. Some members of this class, such as the Chiyoda bubbling jet reactor, can achieve control efficiencies higher than the 97.5% proposed here as BACT. The Application should be revised to identify the full range of scrubbers in each of the classes of scrubbers based on this full range, the Applicant should revisit the degree of reduction used to establish BACT SO_2 limits.

Fourth, the Application implies that BACT is based on the lowest "demonstrated in practice" limit. Ap., p. 4-57 [citing Deseret and Hugo]. This is incorrect. BACT is an emission limit based on the maximum degree of reduction that is "achievable." A limit does not have to be demonstrated in practice to be "achievable." A proposed or final permit limit alone is sufficient to establish BACT as it represents a permitting agency's informed judgment as to what is achievable under the BACT standard of review. The Application should be revised to include permitted and proposed SO_2 limits in the Step 4 ranking. There are many permitted or proposed limits that are much lower than proposed here as BACT including those for Longleaf, Intermountain, Ely, Toquop, Desert Rock, and White Pine.

Fifth, the Application asserts that wet scrubbers use more water than dry scrubbers. Ap., p. 4-56. This is incorrect. A wet scrubber uses less water than a dry scrubber when expressed on a gallon per pound of SO_2 removed basis. The total amount of water used is only higher for a wet scrubber (normally designed for 98% SO_2 control from medium to high sulfur coal) compared to a dry scrubber when the amount of SO_2 removed by the wet scrubber is much higher than the amount of SO_2 removed by a dry scrubber (normally designed for only 90-94% SO_2 control on low-S coal).

F. The BACT Analysis For Lead Is Fundamentally Flawed.

The Application proposes a lead BACT limit of 1.69×10^{-5} lb/MMBtu on a 3-hr average, based on a stack test at Santee Cooper Cross Unit 3. Ap., p. 4-68. There are numerous legal and factual errors in the lead BACT analysis, requiring that the analysis be redone from scratch.

First, the Application inappropriately eliminated coal cleaning as technically infeasible. Ap., p. 4-65. The Application asserts that coal washing would increase the amount of coal burned, thus increasing secondary pollutant emissions while achieving only a "minimal" reduction in lead. *Id.* No support is presented. As noted above, our calculations indicate that SO_2, PM, PM_{10}, fluorides, mercury, lead and many other heavy metal emissions would be reduced not increased. Further, numerous studies have demonstrated that coal cleaning removes a substantial fraction of the lead, up to 90+%.[46] Regardless, slight but unquantified increases in some pollutants and minimal reductions in lead are not valid bases for eliminating a control option as technically infeasible. Coal cleaning combined with other control options, such as a baghouse and wet scrubber, must be evaluated and constitute BACT for lead.

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[46] David J. Akers, Coal Cleaning: A Trace Element Control Option, In: Winston Chow and Katherine K. Conner, Managing Hazardous Air Pollutants: State of the Art, 1993, pp. 483-493; Shawn Michael Conaway, Characterizing Trace Element Associations in the Pittsburgh No. 8, Illinois No. 6 and Coalburg Coal Seams, Masters of Science Thesis, Virginia Polytechnic Institute and State University, July 2001.

Second, BACT is an emission limit based on the maximum degree of reduction that is achievable. The degree of reduction must be determined before one can assert that a given limit is BACT. The analysis fails to disclose the control efficiency represented by the proposed limit. Our calculations from information in the Application (431 ton/hr coal feed rate for a 50:50 blend, firing rate 8300 MMBtu/hr, 8 ppm lead in coal) indicates that the proposed limit corresponds to only 98% lead control. The Application stated that the control efficiency for lead for the top three control options, including the control option selected as BACT, is 99%. Ap., p. 4-66. Thus, the lead BACT limit, based on the Applicant's own analysis, can be no higher than 8.31×10^{-6} lb/MMBtu.

Third, much lower limits have been permitted. The list of lead RBLC listing in Table 4-8 omits all of the determinations that are lower than the limit selected here as BACT. See, for example, Thoroughbred (0.00000386 lb/MMBtu), Trimble Unit 2 Keystone Cogeneration (0.0000046 lb/MMBtu), Spruce Unit 2 (0.0000084 lb/MMBtu), Springerville Units 3 & 4 (0.000016 lb/MMBtu), among others. *Permits and RACT/BACT/LAER Clearinghouse.* Further, as discussed above, BACT is not an emission limit that has been "demonstrated in practice" but rather an emission limit based on the maximum degree of reduction that is "achievable."

Fourth, the lead BACT analysis assumes that "technologies available for the control of Pb emissions are the same technologies available for the control of PM emissions." Ap., p. 4-61. This fundamental assumption underlying the lead BACT analysis is incorrect. Lead is volatilized in the boiler and condenses as very fine particulate matter or nanoparticles (<2.5 microns) in the pollution control train.[47] The highest concentrations of lead are consistently found in the smallest particles.[48, 49] The particulate collection efficiency for baghouses designed to collect PM and PM_{10} (the BACT technology for lead, PM, and PM_{10}) is generally lower for these nanoparticles that contain most of the lead than for larger particles. Thus, a fabric filter system designed to meet BACT for PM and PM_{10} does not necessarily meet BACT for particles smaller than 10 microns where most of the lead is found. These smaller particles also cause proportionately more of the adverse health impacts because they can penetrate deep into the lungs.

The fact that PM/ PM_{10} controls do not provide effective controls for the smaller particles where lead is found has been specifically recognized by the EPA, which stated in its April 2007 $PM_{2.5}$ implementation rule that, "[i]n contrast to PM[10], EPA anticipates that achieving the NAAQS for PM[2.5] will generally require States to evaluate different sources for controls, to consider controls of one or more precursors in addition to direct PM emissions, and to adopt different control strategies."[50] Rather than pretending that the controls for PM_{10} will suffice for lead, the Applicant must conduct a BACT analysis for lead that considers methods to enhance

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[47] R.C. Flagan and S.K. Friedlander, Particle Formation in Pulverized Coal Combustion – A Review, In: *Recent Developments in Aerosol Science*, D.T. Shaw (Ed.), 1978, Chapter 2.

[48] Richard L. Davidson and others, Trace Elements in Fly Ash, *Environmental Science & Technology,* v. 8, no. 13, December 1974, pp. 1107-1113; E.S. Gladney and others, Composition and Size Distribution of In-State Particulate Material at a Coal-Fired Power Plant, *Atmospheric Environment*, v. 10, 1976, pp. 1071-1077.

[49] W.P. Linak and others, Comparison of Particle Size Distributions and Elemental Partitioning from Combustion of Pulverized Coal and Residual Fuel Oil, *J. Air & Waste Manage. Assoc.*, v. 50, 2000, pp. 1532-1544.

[50] Final PM2.5 Implementation Rule, at 20589.

the removal of the finer particles where lead is found. Methods to enhance the control of fine lead particles include: (1) use of a filtration media with a higher removal efficiency for nanoparticles; (2) use of an agglomerator upstream of the baghouse; (3) use of advanced particulate control technologies; (4) a more efficient SO_2 control system; (5) combinations of the foregoing including coal cleaning.[51] These are discussed below.

(1) Filtration Media

Fabric filter baghouses are only as efficient as the bags that they use. The filtration media determines the control efficiency of a baghouse for various particles sizes. There is a wide range of media that can be used, most of which are more efficient for larger particles, 10 microns and up. However, media have been developed over the last decade that remove over 99.9%+ of the 2.5 micron and smaller particles where the lead is found. These include Daikin's AMIREX™, PTFE membrane filters[52] and W.L. Gore's L3650.[53] The lead BACT analysis does not identify the type of filtration media that would be used nor the removal efficiency as a function of particle size, which is required to determine BACT.

(2) Agglomerator

An agglomerator uses electrical charges to attach nanoparticles to larger particles, which are then more efficiently removed by a downstream particle collection device such as a baghouse or electrostatic precipitator.[54] The Indigo Agglomerator was "developed in Australia to reduce visible emissions from coal-fired boilers. The Indigo Agglomerator contains two sections, a bipolar charger followed by a mixing section. The bipolar charger has alternate passages with positive or negative charging. That is, the even passages may be positive and the odd passages negative, or vice versa. This can be contrasted with a conventional coal-fired boiler precipitator, which has only negative charging electrodes. Following the charging sections, a mixing process takes place, where the negatively charged particles from a negative passage are mixed with the positively charged particles from a positive passage. The close proximity of particles with opposite charges causes them to electrostatically attach to each other. These agglomerates enter the precipitator, where they are easily collected due to their larger size.[55]

(3) Advanced Baghouse Collectors

There are several types of advanced baghouse collectors designed specifically to remove $PM_{2.5}$ where most of the lead is found. The EPA's Environmental Test Verification (ETV) program recently verified the performance of the "Advanced Hybrid Particulate Collector"

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[51] See, e.g., Dorothy Lozowski. Dust Collection Focuses on Smaller Particles, Chemical Engineering, March 2006.
[52] McIlvaine Hot Topic Hour, Filter Media Selection for Coal-Fired Boilers, September 13, 2007, Presentation by Todd Brown, Daikin America, Inc. Voice recording available online to subscribers of McIlvaine Power Plant Knowledge System.
[53] USEPA, ETV Joint Verification Statement, Baghouse Filtration Products, W.L. Gore & Associates, L3650 .at http://epa.gov/etv/pubs/600etv06042s.pdf.
[54] McIlvaine Hot Topic Hour, Impact of PM2.5 on Power Plant Choices, November 2, 2006. Voice recording available online to subscribers of McIlvaine Power Plant Knowledge System.
[55] http://www.indigotechnologies-us.com/current_installations.php

(AHPC) system[56] "as providing the lowest filter outlet concentrations for both $PM_{2.5}$ and total mass concentration."[57] The AHPC system is installed at Otter Tail Power's Big Stone coal-fired power plant in South Dakota. Analyzing the performance of the system at that plant, the US Department of Energy explained that:

> The Advanced Hybrid™ consists of alternating electrostatic precipitation and fabric filtration elements in a single casing to achieve exceptional removal of particulate matter (PM) in a compact unit. Very high removal is achieved by removing at least 90 percent of the PM before it reaches the fabric filter and using a membrane fabric to collect the particles that reach the filter surface. . . . Combining precollection with the ESP elements and membrane filter bags results in a small, economical unit that can achieve very high collection of all particle sizes.[58]

The COHPAC is a pulse jet filter module operated at a very high filtration velocity (air-to-cloth ratio), installed downstream of another particle collection device. The function of a COHPAC is as a "polishing filter," collecting the particulate (especially fine particulate) that escapes the primary device. A full-scale COHPAC system has been installed at the Gaston coal-fired power plant near Birmingham, AL.[59]

(4) More Efficient SO_2 Control Device

The Application selected a generic wet scrubber designed to remove 97.5% of the SO_2. There are specific types of wet scrubbers that were not evaluated in the Application that have high removal efficiencies for $PM_{2.5}$. These include the Chiyoda jet bubbling reactor and Alstom's Turbosorp.

G. The BACT Analysis For Sulfuric Acid Mist Is Fundamentally Flawed.

The proposed sulfuric acid mist ("SAM") limit of 0.005 lb/MMBtu based on a 3-hour average does not satisfy BACT. The Application contains detailed analyses for Steps 1 – 4. However, in Step 5, the Application sets aside the analysis in Steps 1- 4 and plucks the excessively high SAM BACT limit of 0.005 lb/MMBtu out of thin air. Ap., 4-88.

First, Step 1 fails to identify all feasible control options. The following are omitted: (1) SCR catalyst washing; (2) a more efficient SO_2 scrubber; (3) air heater additives; and (4) combinations of these methods plus those identified, among others. NSR Manual, p. B.17

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[56] Since its original development, the name of this technology has been changed to "Advanced Hybrid™." The name was trademarked by W.L. Gore and Associates, Inc. *See* Ex. 126, "Demonstration of a Full-Scale Retrofit of the Advanced Hybrid Particulate Collector Technology," U.S. Department of Energy (February 2007) *available at http://204.154.137.14/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/otter/PPA_Otter%20Tail_PPA_Final%20for%20Posting.pdf*

[57] Ex. 127, EPA Test Program Verifies Performance of GORE® Filter Laminate (October 2006) *available at* http://www.gore.com/en_xx/news/epa_test_program_etv.html

[58] *See* Ex 126, "Demonstration of a Full-Scale Retrofit" at 12-13.

[59] R.L. Miller, Enhancing Aging ESP Performance Utilizing COHPAC Hybrid Fabric Filter Technologies, April 2003. http://hamon-researchcottrell.com/HRCTechnicalLibrary/EnhancingAgingESPPerformance.pdf.

("combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels...").

Second, Step 2 inappropriately eliminates two feasible control options --coal cleaning (or washing) and circulating fluidized bed scrubbers.

Coal washing is eliminated because the majority of the sulfur in the coal is alleged to be organic and thus not removed by coal washing. Thus, the Application argues, less than 1% of the sulfur would be removed by washing. Ap., p. 4-81. This is incorrect. For Illinois #6 coal, there is about a 50-50 split of organic to pyritic sulfur, which is the national norm for almost all coals. Further, coal washing increases the heat content of coal because it removes mineral matter (contrary to allegations elsewhere in the Application).

Sulfur emissions are measured relative to the BTUs burned, i.e., in pounds per million Btus. Thus, the reduction in sulfur content, expressed in lb/MMBtu would be much higher than the 1% claimed in the Application. We cannot correct the errors in the Application's analysis because it does not contain design basis coal quality, a sine quo non for BACT analysis and a fundamental flaw of the Application. However, we would expect, based on experience in the industry, that washing of the Illinois #6 coal would remove about 40% of the sulfur, expressed on a lb/MMBtu basis. Coal washing would result in further benefits not considered in the Application, namely, reduced transportation costs, higher heat content, improved boiler efficiency, and reduced operating costs. Coal washing, including of Illinois #6, is widely used. There is no basis for eliminating coal washing as technically infeasible. It should be required in combination with wet scrubbing as BACT for PM, PM_{10}, $PM_{2.5}$, SO_2, lead, fluorides, and SAM.

The Application also erroneously eliminates circulating dry scrubbers because they have not yet been demonstrated on a coal-fired boiler greater than 250 MW. Ap., p. 4-83. In the SO_2 BACT analysis, the Applicant asserts the maximum size is only 100 MW. Ap., p. 4-72. Both assertions are incorrect and irrelevant. Circulating dry scrubbers are currently being bid at up to 440 MW and suppliers claim there is no technical obstacle to a single-module CDS absorber up to 700 MW.[60] Regardless, two 425 MW units in parallel could be used at the facility.

Third, Step 3 fails to rank the technologies that were selected, instead selecting wet scrubbing and sorbent injection without disclosing how much SAM removal would be achieved. Thus, there is no demonstration that the emission limit based on the maximum degree of reduction has been selected. Further, the Application is silent as to the degree of reduction represented by the proposed limit and silent as to whether it represents the maximum degree of reduction that is achievable.

Fourth, the SAM limit included in Application, 0.005 lb/MMBtu, is not BACT for SAM, even assuming the BACT analysis was properly performed. The Application contains a list of SAM limits permitted for other coal-fired boilers, compiled from EPA's RACT/BACT/LAER Cleanringhouse. Ap., Table 4-10, pp. 4-89/90. TWENTY ONE of these limits are LOWER than

[60] Sargent & Lundy, Flue Gas Desulfurization Technology Evaluation, Prepared for the National Lime Association, March 2007.

the SAM BACT limit proposed for the Washington County facility. No explanation is offered for why this facility cannot meet these lower limits. Further, there are many other lower SAM limits that were not included in the Application's RBLC tabulation, including those for Whelan 2, Parish 8, Springfield 2, Sandy Creek, Trimble 2, and Wygen 2.

Fifth, the Application justifies its choice by pointing to a recent draft permit for Toquop that proposes a similar BACT limit for SAM. Ap., p. 4-88. The most recent determination does not establish BACT. Rather, BACT should be based on the maximum degree of reduction that is achievable.

We note that for SAM, the Application relies on a proposed limit in a draft permit, Toquop, and rejects a stack test on a similar facility burning a similar coal (incorrectly claimed to be distinguishable). However, for other pollutants, the Application rejects the lowest limits when present in a draft permit, arguing instead that these permit limits are irrelevant because they have not been demonstrated. This is an intolerable inconsistency. The Santee Cooper coal cannot be both representative and thus the basis for BACT for fluorides (p. 4-75), lead (p. 4-68), VOC (p. 4-45), and PM (p. 4-20) and not representative and thus not establish BACT for SAM. In fact, both draft permit limits and stack tests are reasonable bases for selecting BACT. Best is best. The Applicant should not be allowed to shop for its BACT limit by selecting the highest among test results and draft permits, the reverse of a proper BACT analysis. The Applicant must apply a consistent analysis procedure for each pollutant that comports with the definition of BACT. Tossing out the lowest value is not consistent with BACT.

Sixth, once the control options that yield that the maximum degree of reduction have been identified, and we submit these must include washing of Illinois #6 coal, minimizing the amount of Illinois #6 coal that is burned, a SCR catalyst with an $SO_2$to SO_3 conversion rate of no more than 0.5%, advanced wet scrubbing, and a wet electrostatic precipitator, the Applicant should calculate the achievable SAM limit from vendor design information and coal quality.

Finally, even though the Application concludes that coal selection is technically feasible in Step 2, it fails to explain how coal selection was used in determining BACT. The BACT limits are based on a 50:50 blend of low sulfur PRB coal and high sulfur, high ash Illinois #6 coal. Much lower emission limits could be achieved by burning a higher percentage of PRB coal. This option, though concluded to be feasible, was not evaluated in subsequent steps of the BACT analysis.

H. The BACT Analysis Fails To Set Limits In Pounds Per Megawatt-Hour.

BACT limits should also be expressed 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." This analysis should consider more efficient combustion technologies, such as ultra supercritical boilers and IGCC.

I. The BACT Analysis Fails To Set Limits For Each Type Of Coal.

The facility is being designed to burn "up to" a 50:50 blend of PRB and Illinois #6 coal. Ap., p. 2-1. It is unclear exactly what "up to" means. We presume it means that the facility may burn anywhere from 100% PRB as well as various blends of PRB and Ilinois #6, so long as no more than 50% of the mix is Illinois #6. The Application should clarify the range of coals that would be burned. Because BACT must consider clean fuels, the specific blend that results in the lowest emissions should be evaluated in the BACT analyses. Alternatively, if the range of fuels is 100% PRB up to a 50:50 blend, the Application should set separate BACT limits for each unique fuel, e.g., PRB, Illinois #6, and then stipulate that the applicable emission limit for any blend of the two shall be determine based on the relative proportions of each. This approach was followed in the Longleaf permit.

J. The Applications Contains No BACT Analysis For Opacity.

The application fails to include a BACT determination for opacity. This exclusion is inconsistent with the definition of BACT. 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.

K. The Application Contains No BACT Analysis For $PM_{2.5}$.

The Applicant must do a BACT analysis for $PM_{2.5}$. 40 CFR § 52.21(j)(2) requires a new major stationary source to apply BACT to each regulated NSR pollutant that it emits in significant amounts. 40 CFR § 52.21 (b)(23) defines "significant." For a NSR pollutant not listed in 40 CFR § 52.21(b)(23)(i), "significant means . . . _any_ emission rate." 40 CFR § 52.21(b)(23(ii) (emphasis added). Because PM 2.5 is a regulated NSR pollutant that Plant Washington (a new major source) will emit in some quantity, the Applicant must apply BACT to PM 2.5.

The Application addresses the control of $PM_{2.5}$ emissions using PM_{10} as a surrogate. Ap., p. 3-11. However, PM_{10} should not be used as a surrogate for $PM_{2.5}$. PM_{10} and $PM_{2.5}$ are separate and distinguishable pollutants, with separate National Ambient Air Quality Standards. Thus, a separate BACT analysis and ambient air quality analysis should be prepared for $PM_{2.5}$.

L. The BACT Analysis For PM/ PM_{10} Is Fundamentally Flawed.

The Application improperly eliminates coal selection as technically infeasible without any analysis and based solely on erroneous, unsupported assertions. First, the Application claims that any lower ash fuel could have a higher sulfur content and thus cause increased SO_2 emissions. Ap., p. 4-16. While this is true for some coals, it is not true for all coals. PRB coal, for example, has much lower ash content and much lower sulfur content than the proposed Illinois #6 coal. Thus, 100% PRB coal (and other sub-bituminous coals) should have been evaluated in Steps 3-5 of the top down analysis. Second, the Application claims that coals are not typically sorted by ash content. *Id.* This makes no sense. Ash content is one of the parameters typically specified in coal contracts and one of the parameters typically measured at the mine. Regardless, coal sorting methods are not valid bases for eliminating a control option as technically infeasible.

The Application also improperly eliminates coal cleaning as technically infeasible for both PM/ PM_{10} and SO_2 without any analysis and based solely on erroneous, unsupported assertions.

First, the Application asserts that coal washing would lead to an increase in the amount of coal burned, thus increasing secondary pollutant emissions, such as SO_2. The Application should present calculations to support this contention. Our calculations indicate that SO_2, PM, PM_{10}, fluorides, mercury, lead and many other heavy metal emissions would be reduced not increased as coal cleaning also removes sulfur and these other constitutes. Further, any increase in other pollutants, such as NOx, CO or VOC, due to washing are de minimus compared to the reduction in particulate matter, SO_2, lead, mercury, and other heavy metals.

Second, the Application implies that PM and SO_2 emission reductions would be minimal, but fails to provide an estimate or any cite for this assertion. Regardless, minimal reduction is not a basis for eliminating a control option as technically infeasible. Coal cleaning combined with other control options, such as a baghouse and wet scrubber, must be evaluated and constitute BACT.

The Application incorrectly states that electro-catalytic oxidation is only in the pilot scale testing stages of development thus should not be considered available for BACT review for PM_{10}, NOx, etc. This is incorrect. The technology has been demonstrated on a commercial scale and is being quoted and has been selected for new coal-fired power plants as wells as retrofits of existing plants.

M. The BACT Analysis For VOC Is Fundamentally Flawed.

The Application proposes a VOC limit of 0.0034 lb/MMBtu on a 3-hr average. This determination is not BACT for VOCs. The flaws previously noted for the CO BACT analysis are also present in the VOC BACT analysis. Thus, the CO comments are incorporated here by reference except as noted below.

The Application argues that the VOC (and CO) limits should be sacrificed in favor of NOx, which is more "sensitive." However, this argument is especially egregious for VOC because many facilities with lower VOC limits also have lower NOx limits than proposed for Washington County, e.g., Parish Unit 8, Toquop, Desert Rock, and Trimble Unit 2. Note that a 24-hour or a 30-day average is much more stringent than an annual average (as proposed for Washington County), all else being equal.

N. The BACT Analysis For Fluorides Is Fundamentally Flawed.

The Application proposes a fluoride (called "HF" in the Application) BACT limit of 0.0003 lb/MMBtu on a 3-hr average. Ap., p. 4-75. This determination is not BACT for HF. The flaws previously noted for sulfuric acid mist are present in the HF BACT analysis, except as otherwise discussed below. Thus, the sulfuric acid mist comments are incorporated here by reference.

The Step 5 HF analysis makes the same erroneous analysis as proffered in Step 5 of the lead BACT analysis. It tosses out all lower permitted emission limits, arguing that they have not been demonstrated in practice and instead selects as BACT the limit from a single stack test at Santee Cooper Cross Unit 3. Ap., p. 4-75. However, elsewhere in the Application, it is argued that the Santee Cooper Cross coal is distinguishable. The Applicant has presented absolutely no data to support or refute the similarity between its coal and Santee Cooper's coal for any pollutant. Thus, it has no basis for relying on a single stack test in the face of numerous BACT determinations to the contrary. The Applicant's own summary of HF limits from the RACT/BACT/LAER Clearninghouse includes six facilities with lower HF limits, ranging from 0.0001 to 0.00024 lb/MMBtu. The HF limit should be estimated from the amount of fluoride in the coal and the control efficiency achievable by the proposed pollution control train. The design of the SO2 scrubber should be optimized to assure that the maximum degree of reduction of HF is achieved.

II. MACT ANALYSIS

With respect to the facilities emissions of hazardous air pollutants, including mercury, the comments submitted by the Southern Environmental Law Center are hereby incorporated by reference.

III. PRE-APPLICATION MONITORING REQUIREMENTS HAVE NOT BEEN MET.

Nothing in the application material suggests that the pre-application analysis required by 40 C.F.R. § 52.21(m), *see also* Georgia Rule Georgia Rule 391-3-1-.02(7)(b)(10) (incorporating 40 C.F.R. § 52.21(m) by reference), have been complied with. The application should be returned so that these requirements can be met.

IV. GEORGIA EPD MUST CONSULT WITH FISH AND WILDLIFE SERVICE REGARDING THE EFFECT OF CARBON EMISSIONS ON ENDANGERED SPECIES.

The Endangered Species Act (ESA) was enacted to conserve endangered and threatened species and the ecosystems which they depend upon. *See* Endangered Species Act, 16 U.S.C. § 1531(b). Under the statute, "all Federal departments and agencies shall seek to conserve endangered species and threatened species and shall utilize their authorities in furtherance of the purposes of the Act." 16 U.S.C. § 1531(c)(1) (ESA § 2(c)(1)). The ESA defines "conservation" to mean "the use of all methods and procedures which are necessary to bring any endangered species or threatened species to the point at which the measures provided pursuant to [the Act] are no longer necessary.'" 16 U.S.C. § 1532(3) (ESA §3(3)).

Section 7 consultation is required for "any action [that] may affect listed species or critical habitat." 50 C.F.R. § 402.14. Agency "action" is defined in the implementing regulations to include:

> all activities or programs of any kind authorized, funded, or carried out, in whole or in part, by Federal agencies in the United States or upon the high seas. Examples, include, but are not limited to: (a) actions intended to conserve listed species or their habitat; (b) the promulgation of regulations; (c) the granting of licenses, contracts, leases, easements, rights-of-way, permits or grants-in-aid; or (d) action directly or indirectly causing modifications to the land, water, or air.

50 C.F.R. § 402.02. EPA has been clear that the section 7 consultation requirement of the ESA applies to the issuance of PSD permits by a state agency such as EPD acting under a delegated PSD program. *See In re Indeck-Elwood, LLC*, PSD Appeal No. 03-04, slip op. at 109, 13 E.A.D. __ (Sept. 27, 2006).

The most significant environmental issue associated with Plant Washington is the enormous global warming emissions resulting from the burning of pulverized coal. In short, the action of granting this permit will allow the emissions of millions of tons of carbon dioxide per year for the foreseeable future.

Greenhouse gas emissions are having a direct and indirect impact on numerous listed species. The IPCC has reported that 30 percent of animal and plant species could be at an increased risk of extinction if global warming continues unabated.[61] Another recent report chronicles the various types of extinction threats posed by global warming.[62]

Undeniably, the global warming pollution associated with Plant Washington "may affect" endangered species, which triggers the consultation requirement.

V. GEORGIA EPD SHOULD CONDUCT AN ALTERNATIVES ANALYSIS THAT CONSIDERS GLOBAL WARMING IMPACTS.

Georgia EPD, as the delegated permitting authority, should require an evaluation of CO_2 emissions and establish appropriate permit conditions or otherwise address these emissions. EPA's Office of Air and Radiation, Office of General Counsel, and the Environmental Appeals Board have expressed the opinion that permitting authorities have broad discretion to consider alternatives, conduct or require analyses, and impose permit conditions to address issues under CAA section 165(a)(2) beyond the required BACT analysis. *See In re Prairie State*, PSD

[61] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007:* Fourth Assessment Report, Synthesis Report, *available at* http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr_spm.pdf

[62] Randall, J., *Climate Change, Wildlife and Endangered Species (2007).*

Appeal 05-05, 12 E.A.D. __ (Aug. 24, 2006); *In re Knauf Fiber Glass*, 8 E.A.D. 1212, (EAB 1999); *In re Hillman Power*, 10 E.A.D. 673, 692 (EAB 2002).[63] The EAB has consistently held that states have broad discretion to consider various options, including, among other things, broad discretion to independently evaluate options and alternatives, and to adopt conditions or requirements that they deem appropriate. For example, the Board has held that a permitting authority may require "redefinition of the source," including requiring or restricting certain fuels. *Hillman Power*, 10 E.A.D. at 692.

EPA has recognized that "a PSD permitting authority still has an obligation under section 165(a)(2) to consider and respond to relevant public comments on alternatives to the source," and that a "PSD permitting authority *has discretion under the Clean Air Act to modify the PSD permit based on comments raising alternatives* or other appropriate considerations." BRIEF OF THE EPA OFFICE OF AIR AND RADIATION AND REGION V, *In re Prairie State*, PSD Appeal 05-05, 12 E.A.D. __ (EAB, Aug. 24, 2006). Moreover, the EAB has made clear that a permitting authority has discretion to modify a permit based on consideration of "alternatives" whether or not the issues are raised by commenters:

> Indeed, the permit issuer is not required to wait until an "alternative" is suggested in the public comments before the permit issuer may exercise the discretion to consider the alternative. Instead, the permit issuer *may identify an alternative on its own*. This interpretation of the authority conferred by CAA section 165(a)(2)'s reference to "alternatives" is consistent with the Agency's longstanding policy that, . . . "this is an aspect of the PSD permitting process in which *states have the discretion to engage in a broader analysis if they so desire*."

See In re Prairie State, PSD Appeal 05-05 (Aug. 24, 2006) (quoting the NSR Workshop Manual at B.13).

In fact, under this authority, a permitting authority can engage in a wide-ranging exploration of options, including fuel switching, and other generation and non-generation alternatives.[64] Under this authority EPD clearly has the discretion to require specific evaluation and control of CO_2 emissions, and/or to require other action to mitigate potential global warming impacts. Failure to do so in this case is a material breach of the agency's obligations to the people of Georgia and the United States.

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[63] This discretion even extends to requiring specific additional BACT analysis. In *Knauf*, the Board explained that although "[s]ubstitution of a gas-fired power plant for a planned coal-fired plant would amount to redefining the source . . . redefinition of the source is not always prohibited. This is a matter for the *permitting authority's discretion. The permitting authority may require consideration of alternative production processes in the BACT analysis when appropriate. See* NSR Manual at B.13-B.14; Old Dominion, 3 E.A.D. at 793 (permit issuer has discretion "to consider clean fuels other than those proposed by the permit applicant.")." *Knauf*, 8 E.A.D. at 136 (emphasis added).

[64] For a thorough analysis of the factors, including CO_2 emission reductions options, to be considered in the alternatives analysis for new power plants, see the article by EPA Office of General Counsel attorney Gregory Foote entitled, "Considering Alternatives: The Case for Limiting CO_2 Emissions From New Power Plants Through New Source Review." 34 Envt'l L. Rev. 10642 (2004).

Among the alternatives EPD should consider under § 165(a)(2) of the Act is the "no-build" option, under which EPD would deny the PSD permit based on policy considerations related to CO_2.[65] The state of Georgia is rich in alternative sources of energy which, if developed, would provide an alternative to building Plant Washington. Such alternatives include renewables and energy efficiency.

VI. THE MODELING ANALYSIS IS FUNDAMENTALLY FLAWED.

A. The Class I Areas Modeling Analysis is Flawed.

1. Air quality and visibility impact modeling used meteorological data whose validity and accuracy have not been evaluated.

The Calpuff model is the principal model used for air quality and visibility impact analyses of the proposed Plant Washington. Normally, the Calpuff modeling uses meteorological data generated by appropriate mesoscale models for three consecutive years and at spatial resolution fine enough to simulate accurately pollutant transport in the study region. In this modeling study, meteorological data used by the Calmet preprocessor to generate the hourly, three-dimensional windfields required by the Calpuff modeling are based on outputs of the mesoscale model MM5 that were generated by VISTAS for the years 2001-2003. These MM5 runs used coarse grid resolutions of 12 km for 2001 and 2002, and 36 km for 2003. These coarse MM5 data are then used by the Calmet preprocessor to generate three-dimensional wind fields for use by the Calpuff model. The Calmet/Calpuff wind fields are based on a horizontal resolution of four kilometers. The wind fields and meteorological inputs generated by the Calmet preprocessor have not been evaluated before their use in the Calpuff modeling. A quantitative performance evaluation of these meteorological inputs against actual measurements in the modeling region should be performed to evaluate their validity and accuracy. Similar to the 2002 MM5 evaluation performed by VISTAS, both graphical and statistical measures should be used in the performance evaluation.[66] Further, the meteorological inputs should be shown to be applicable to assessment at the PSD Class I areas, e.g. backward/forward trajectories should be generated to show whether or not pollutant plumes from Plant Washington will be transported to and impacting those areas. Such trajectory analysis will provide information on the magnitude, duration and frequency of Plant Washington plumes impacting the PSD Class I areas.

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[65] The Board has said:

> We are unable to reconcile the view that consideration of need for a facility is outside the scope of section 165(a)(2) of the Clean Air Act with the text of the statute and prior decisions. The statutory text's plain meaning does not lend itself to excluding public comments that request consideration of the "no build" alternative to address air quality concerns. Moreover, the Board's and Administrator's prior decisions would appear to recognize that consideration of "need" is an appropriate topic under section 165(a)(2). *See In re EcoEléctrica*, LP, 7 E.A.D. 56, 74 (EAB 1997)

In re Prairie State, PSD Appeal 05-05, 12 E.A.D. __ (EAB Aug. 24 2005).

[66] Abraczinskas, M.A. et al., 2004. *Characterizing Annual Meteorological Modeling Performance for Visibility Improvement Strategy Modeling in the Southeastern US.* Available from the VISTAS website http://www.vistas-sesarm.org

2. Air quality and visibility impacts have been understated due to the omission of emissions of auxiliary boilers and other low-level sources.

In the Calpuff modeling of air quality and visibility impacts at PSD Class I areas, only emissions from the main boiler were modeled, and emissions from the auxiliary boiler 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 the auxiliary boiler and other low-level sources. For a conservative modeling analysis, emissions from these sources should be added to those from the main boiler.

3. SO_2 3-hour impacts are underestimated due to low emissions.

The same SO_2 emissions rate (125.50 g/s or 996 lbs/hr) was used in the modeling of both SO_2 3-hour and 24-hour impacts. A higher emission rate is usually used in modeling 3-hour impacts due to load fluctuations and startup conditions.

4. No $PM_{2.5}$ PSD Class I increment analysis has been performed.

US EPA has proposed in September 2007 PSD increments and significant impact increments for $PM_{2.5}$ (particulate matter with less than 2.5 microns in diameter). $PM_{2.5}$ emissions from Plant Washington should be quantified and their impacts modeled at PSD Class I areas. $PM_{2.5}$ impacts should include not only the concentrations from the $PM_{2.5}$ primary emissions but also the secondary contributions due to chemical conversion of precursor emissions of SO_2, NOx and VOC. These secondary contributions can be larger than the $PM_{2.5}$ concentrations from primary emissions. The modeled impacts should be compared against the EPA-proposed PSD Class I increments of 2 ug/m3 (24-hour) and 1 ug/m3 (annual).

5. Visibility impacts are understated due to the use of a low relative humidity.

A maximum relative humidity (RHMAX) of 95% has been used in the visibility impact modeling. This 95% value is lower than the 98% value that is the default in Calpost. It is also recommended in the FLAG manual (FLAG, 2000). Visibility impacts are substantially lower when using a lower maximum relative humidity.

6. Visibility impacts are understated due to the use of a low ammonia background concentration.

A background ammonia concentration of 0.5 ppb has been used in the visibility impact modeling. This 0.5 ppb value is lower than the 1.0 ppb value that is the default in Calpost. It is also recommended in the FLAG manual (FLAG, 2000). Visibility impacts are substantially lower when using a lower ammonia background.

7. PM_{10} emissions were modeled incorrectly in the visibility impact modeling and the results of the visibility analysis are invalid.

PM_{10} emissions from Plant Washington were modeled as fine particulate matter (PM) in the visibility impact modeling. This is a gross error and, therefore, the results of the visibility analysis in the PSD Permit Application are considered to be erroneous and invalid. As shown in the VISTAS BART Protocol, PM_{10} emissions should be divided into filterable and condensable species (VISTAS, 2005). Filterable species are further separated into elemental carbon, soil/ $PM_{2.5}$ and coarse PM. Condensable species include sulfates, non-sulfate inorganics and organic carbon.

8. Visibility impacts are understated due to the omission of organic carbon emissions

Organic carbon (OC) from PM emissions has been neglected in the visibility impact modeling. National Park Service has recommended 9.8% of total PM_{10} as OC for a coal-fired boiler burning pulverized coal with wet FGD (NPS, 2006). As shown in Table 3-1 of the PSD Permit Application, the PM_{10} emission rate of the main boiler will be 654 tons per year. Using the 9.8% value, the OC emissions will be 64.1 tons per year. Visibility impacts are substantially lower when neglecting organic carbon.

9. Visibility impacts are understated due to the omission of sulfuric acid and hydrogen fluorides.

Table 3-1 of the PSD Permit Application indicates that Plant Washington will emit 182 tons per year in sulfuric acid (H2SO4) and 10.91 tpy in hydrogen fluorides (HF). These H2SO4 and HF emissions have been omitted in the visibility impact modeling. Visibility impacts are substantially lower when neglecting sulfuric acid and hydrogen fluorides.

10. 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 Plant Washington, there are several facilities in the cumulative SO_2 inventory that have large emissions of SO_2. These facilities not only emit SO_2 but also large amounts of NO_x and PM that can cause visibility impairment. Thus, cumulative visibility impacts at seven PSD Class I areas that are located within 300 km of Plant Washington need to be performed as recommended by the FLAG manual.

B. The Class II Areas Modeling Analysis is Flawed.

1. Air quality impacts have been underestimated due to the use of coarse receptors.

Air quality modeling for PSD Class II areas was performed with the Aermod model. This modeling used two grids of receptors: an inner grid within 2 km of the plant with a 100-m resolution and an outer grid from 2 km to 10 km with a 500-m resolution. If the maximum concentration is predicted to occur within this outer grid (e.g. 24-hour SO_2 screening modeling), only four receptors around the modeled maximum receptor have been added to the modeling. This may lead to missing the true maximum impact. To accurately model the maximum impact, a refined grid of 100 (=10x10) receptors at a 100-m resolution should be placed around the modeled maximum receptor.

2. $PM_{2.5}$ emissions have been estimated using AP-42 data deemed unreliable by Georgia EPD.

Exhibit A of the PSD Permit Application shows that $PM_{2.5}$ emissions from the main boiler have been estimated as 57.10% of the PM_{10} emissions. The source of this speciation factor is AP-42 Section 1.1. This factor has received an E rating in AP-42. It has been judged to be inaccurate and unreliable by Georgia EPD during its review of our comments submitted for the Longleaf PSD Application. The Applicant should be required vendor-specific data regarding this issue.

3. $PM_{2.5}$ impacts have been underestimated and may cause violations of $PM_{2.5}$ standards.

The Plant Washington PSD Permit Application does 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.

As shown in Comment 2 above, $PM_{2.5}$ emissions from the main boiler has been estimated from AP-42 data that has been judged to be unreliable by Georgia EPD. Nevertheless, the $PM_{2.5}$ modeling results presented in the PSD Permit Application has underestimated the $PM_{2.5}$ impacts since they only include the primary emissions but not the secondary formation due to chemical conversion. Secondary $PM_{2.5}$ formation is known to contribute more than 50% to $PM_{2.5}$. $PM_{2.5}$ impacts from Plant Washington can have serious consequences for Washington County. A review of $PM_{2.5}$ monitoring data in Sandersville, Washington County indicates that in the most three recent years (2005-2007), the annual standard of 15 ug/m3 has been exceeded in 2006 (16.1 ug/m3). This standard has been almost exceeded in both 2007 (14.8 ug/m3) and 2005 (14.7 ug/m3). The 24-hour standard of 35 ug/m3 has not been exceeded by the 98th percentiles recorded during 2005-2007 (28 ug/m3 in 2007, 30 ug/m3 in 2006 and 32 ug/m3 in 2005). However, the highest 24-hour measurements in 2007 (39 ug/m3) and 2005 (36 ug/m3) are above the standard.

Modeling results shown in Table 5-5 of the PSD Permit Application show that a maximum annual-averaged concentration of 0.19 ug/m3 has been predicted by the Aermod model with the primary $PM_{2.5}$ emissions and the 1989 meteorological data. To account for secondary formation, combined $PM_{2.5}$ is assumed to be twice the concentration modeled solely with primary emissions. Maximum $PM_{2.5}$ annual concentration from Plant Washington will then be 0.38 ug/m3. When added to the 2007 background of 14.8 ug/m3, total $PM_{2.5}$ concentration from Plant Washington (0.38+14.8=15.18 ug/m3) alone will exceed the annual standard of 15 ug/m3.

4. Project startup and shutdown were modeled incorrectly.

Project startup and shutdown were modeled for specific modeling days using the option HOUREMIS in the Aermod model. This is incorrect since startup and shutdown may not be known in advance and the selected modeling days may not represent worst-case meteorological conditions. The option HROFDAY should be used for modeling startup and shutdown emissions.

5. Cumulative SO_2 modeling was only performed for receptors located within the significant impact areas.

Screening modeling for SO_2 in Table 5-9 of the PSD Permit Application indicates that significant impact levels (SIL) are exceeded for all averaging times (3-hour, 24-hour and annual). The significant impact area (SIA) for 3-hour averages has a radius of 1.85 km around the proposed facility, a radius of 5.38 km for 24-hour averages and a radius of 1.65 km for annual averages. Cumulative modeling have been performed with only receptors located within the significant impact areas (SIA). This use of SIL and SIA to limit the modeled receptors has not been recommended or approved by the US EPA. Cumulative modeling should use 100-m receptors located within 50 km of Plant Washington. This 50-km radius is the limit of applicability of the Aermod model. With extended receptors, Plant Washington and other cumulative facilities may cause violations of NAAQS and/or exceedances of PSD Class II increments.

6. Short-term SO_2 cumulative impacts have been understated due to the use of annual-averaged emissions.

Short-term (3-hour and 24-hour) cumulative modeling used the same annual-averaged emissions for cumulative facilities in the annual cumulative modeling. The US EPA NSR Workshop Manual has recommended the use of maximum allowable or permitted emissions in cumulative modeling (US EPA, 1990). Maximum short-term (3-hour and 24-hour) emissions that are higher than annual-averaged emissions will result in higher impacts.

7. Project will emit several toxic chemicals and their health risks have not been fully quantified.

A coal-fired power plant such as Plant Washington will emit several toxic chemicals that are known to be carcinogens and/or to cause noncancer acute and chronic health effects. Table 6-2 of the PSD Permit Application shows that the project will emit several toxic substances, including arsenic, dioxins, fluorides, mercury and PAH. 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 10.91 tpy.

An ambient assessment of toxic emissions was performed and documented in Section 6 of the PSD Permit Application. This assessment follows the EPD toxic assessment guideline (Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions, EPD, GA DNR, Revised June 1998). The EPD guideline only recommends the comparison of maximum short-term and annual concentrations against acceptable ambient concentrations. Hence, only inhalation risks have been considered and the toxic assessment ignores health risks from non-inhalation pathways. For some substances such as arsenic and mercury, non-inhalation risks such as risks from ingestion of food, soil and drinking water can be much larger than those from inhalation risks alone. The EPD guideline also does not consider the additive effects of toxic substances. As shown in Table 6-2, several substances such as anthracene, benzo(a)pyrene and chrysene have been analyzed separately. All these substances should be combined as a single compound known as PAH. Further, the EPD guideline does not consider combined health risks to specific target organs and toxicological endpoints such as blood, lungs, liver. Thus, by following the Georgia EPD guideline, the toxic assessment has underestimated the health risks from Plant Washington.

A full health risk assessment quantifies the cancer risks from carcinogens due to both inhalation and non-inhalation pathways. For noncancer health effects, it computes hazard indices for acute and chronic exposure for specific target organs and toxicological endpoints. Such a risk assessment will need to be conducted to assess potential health effects of the toxic chemicals emitted by Plant Washington as part of public health and environmental justice concerns.

8. Health effects of mercury emissions have been understated.

Exhibit A of the PSD Permit Application shows that the main boiler will emit a significant amount of mercury (0.06 tpy=120 lbs/yr). These mercury emissions were used in the toxic assessment based on the EPD toxic assessment guideline. As shown in Comment 7 above, only the inhalation risk has been considered in the toxic assessment. Mercury is known to be a neurotoxin and its greatest health risks are from ingestion of fish that are contaminated with methylmercury.

9. The toxic assessment used the obsolete ISCST3 model.

For toxic substances that exceed the acceptable ambient concentrations such as arsenic, hexavalent chromium, hydrogen chloride and sulfuric acid, refined modeling was performed with the ISCST3 model. According to the US EPA Modeling Guidelines, the ISCST3 model has been officially replaced by the Aermod since December 2006. The toxic assessment should use the Aermod model for refined modeling. The EPD toxic guideline should also be updated to reflect this model change.

10. Building downwash was not considered in ISCST3 modeling.

A review of the ISCST3 modeling indicates that the effects of building downwash were not considered. Building dimensions generated by the program BPIP developed by the US EPA should be used to generate the appropriate building dimensions for input to the ISCST3 model.

11. Project impacts on ozone air quality may be significant but they have not been addressed.

The proposed Plant Washington will emit large amounts of NO_x (1,836 tpy) and VOC (124 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 NOx emissions from Plant Washington to form high levels of ozone. Ozone modeling was not performed to assess the impacts of project emissions on ozone air quality in Washington County and other nearby areas. There is no ozone monitor in Washington County. Section 5.1 of the PSD Permit Application has noted that the 8-hour ozone standard of 0.08 ppm has been exceeded in 2006 by a maximum of 0.09 ppm recorded in neighboring counties (Bibb, Columbia and Richmond). In June 2007, US EPA has proposed to lower the 8-hour ozone NAAQS from 0.08 ppm to 0.07-0.075 ppm. Additional precursor NOx and VOC emissions from the Plant Washington will exacerbate the existing ozone air quality and may lead to the declaration of the non-attainment of the new lower 8-hour standard in Washington County and neighboring areas.

12. Project SO_2 emissions can cause significant impacts on sensitive soils and vegetation.

Section 8.2 of the PSD Permit Application has identified several plant species in the area around Plant Washington that are sensitive to sulfur dioxide and ozone. For sulfur dioxide and other pollutants, Table 8-2 indicates 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 (1980). For SO_2, US EPA has recommended 917 ug/m3 for 1-hour averages and 786 ug/m3 for 3-hour averages. These screening levels were based on studies in the 1970s and more recent research, especially in Europe, have indicated that they are not protective of sensitive plant species. United Kingdom and several countries in the European Union have adopted a 1-hour ambient standard of 350 ug/m3. Poland has a short-term standard of 250 ug/m3 for sensitive plants and crops (Regional Environmental Center, 1998). Table 8-2 shows that total 1-hour SO_2 concentration from Plant Washington will be 276 ug/m3 that exceeds the short-term standard of 250 ug/m3 adopted by Poland. Thus, maximum project SO_2 1-hour concentrations will exceed the threshold level for sensitive plants, and can cause significant impacts on local sensitive soils and vegetation.

13. Project ozone impacts on sensitive crops and plants have not been analyzed.

Section 8.2 of the PSD Permit Application has identified several plant species in the area around Plant Washington that are sensitive to sulfur dioxide and ozone. Ozone is a secondary pollutant that is formed under sunlight from precursors NOx and VOC. Plant Washington will emit large amounts of NO_x (1,836 tpy) and VOC (124 tpy). The PSD Permit Application has not presented an impact analysis of either ozone or VOC as a surrogate. US EPA (1980) has recommended VOC screening levels of 392 ug/m3 (1-hour), 196 ug/m3 (4-hour) and 118 ug/m3 (8-hour). It should be noted that these screening levels were based on studies in the 1970s and may not be protective of crops and plants in the area around Plant Washington.

In addition to those sources described above, this section of the comments also relied upon the following sources, all of which are available upon request:

Federal Land Managers Air Quality Related Values Workgroup (FLAG), Phase I Report (2000).

National Park Service, 2006. Particulate Matter Speciation- Coal-fired Boilers PM_{10}. Available at http://www2.nature.nps.gov/air/permits/ect/ectCoalFiredBoiler.cfm

Regional Environmental Center, 1998. Reduction of SO_2 and Particulate Emissions. Available at http://www.rec.org/REC/Publications/SO2/SO2.pdf

Tran, Khanh, 2001b. *ACEHWCF – A Comprehensive Risk Assessment Model for Hazardous Waste Combustion Facilities*. A&WMA Hazardous Waste Combustors Specialty Conference, Kansas City, March 2001. Available from AMI's website http://www.amiace.com

US EPA, 1990. *New Source Review Workshop Manual. Draft October 1990.*

U.S. EPA, 1980. *Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*, EPA 450/2-81-078, December 1980.

VISTAS, 2005. *Protocol for the Application of the CALPUFF Model for BART.*

VII. THE APPLICATION MUST BE SUBMITTED AND REVIEWED BY PROFESSIONAL ENGINEERS LICENSED IN GEORGIA.

In Georgia, "it shall be unlawful for any person other than a professional engineer to practice or to offer to practice professional engineering in this state." O.C.G.A. § 43-15-7. The terms "professional engineer" and "professional engineering" are defined by statute. O.C.G.A. § 43-15-2.

The term "Professional engineering" means:

> [T]he practice of the art and sciences, known as engineering, by which mechanical properties of matter are made useful to man in structures and machines and shall include any professional service, such as consultation, investigation, evaluation, planning, designing, or responsible supervision of construction or operation, in connection with any public or private utilities, structures, buildings, machines, equipment, processes, works, or projects, wherein the public welfare or the safeguarding of life, health, or property is concerned or involved, when such professional service requires the application of engineering principles and data and training in the application of mathematical and physical sciences. A person shall be construed to practice or offer to practice professional engineering, within the meaning of this chapter who by verbal claim, sign, advertisement,

> letterhead, card, or in any other way represents or holds himself out as a professional engineer or engineer or as able or qualified to perform engineering services or who does perform any of the services set out in this paragraph. Nothing contained in this chapter shall include the work ordinarily performed by persons who operate or maintain machinery or equipment.

O.C.G.A. § 43-15-2(11) (emphasis added). The term "professional engineer" means:

> [A]n individual who is qualified, by reason of knowledge of mathematics, the physical sciences, and the principles by which mechanical properties of matter are made useful to man in structures and machines, acquired by professional education and practical experience, to engage in the practice of professional engineering and who possesses a current certificate of registration as a professional engineer issued by the board.

O.C.G.A. § 43-15-2(10) (emphasis added). The term "the board" as used in the above definition means "the State Board of Registration for Professional Engineers and Land Surveyors." O.C.G.A. § 43-15-2(1).

Thus, in order to lawfully practice professional engineering in the State of Georgia, one must be a professional engineer as defined by Georgia law. In order to be considered a professional engineer in Georgia, one must receive certification from the Georgia Board of Registration for Professional Engineers and Land Surveyors.

Absent this certification, it is unlawful to practice professional engineering. As stated in the Georgia Code, it is "unlawful for any person other than a professional engineer to practice or to offer to practice professional engineering" in Georgia. O.C.G.A. § 43-15-7.

In order to issue a PSD Permit, both the Applicant and EPD make BACT determinations. The Georgia Board of Registration for Professional Engineers and Land Surveyors has ruled that BACT determinations constitute the practice of engineering. Minutes, Meeting of the Georgia Board of Registration for Professional Engineers and Land Surveyors, December 6, 1994; Minutes, Meeting of the Georgia Board of Registration for Professional Engineers and Land Surveyors, December 10, 1991. As such, EPD must ensure that both the determinations made by the Applicant and the permitting agency are performed by properly licensed professional engineers.

For the reasons stated above, we respectfully request that the Plant Washington Application be returned to the Applicant. If you have any questions about these comments, would like any of the source material referenced in these comments, or require any additional information, please do not hesitate to contact us at (404) 659-3122.

Thank you for your consideration of this important matter.

Sincerely,

George Hays w/p WHT

George Hays
Senior Attorney

Justine Thompson
Executive Director

Ela Orenstein
Staff Attorney