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October 27, 2009

Via U.S. Certified Mail Return Receipt Requested

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Via U.S. Certified Mail Return Receipt Requested

Plant Washington Comments
Georgia Department of Natural Resources
Environmental Protection Division
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Re: Comments on Plant Washington draft Prevention of Significant Deterioration (PSD) and 112(g) Case-by-Case Maximum Achievable Control Technology (MACT) Determination Construction Permit No. 4911-303-0051-P-01-0.

Dear Jac:

Please accept these comments prepared by GreenLaw and the Southern Environmental Law Center on the Georgia Environmental Protection Division's ("EPD") proposed Prevention of Significant Deterioration (PSD) and 112(g) Case-by-Case Maximum Achievable Control Technology (MACT) Determination Construction Permit No. 4911-303- 0051-P-01-0 Plant Washington, Sandersville, Georgia. These comments are submitted on behalf of the following organizations:

Altamaha Riverkeeper
Center for a Sustainable Coast
Eco-Action
Fall-Line Alliance for a Clean Environment
Friends of the Chattahoochee

Georgia Coalition for the People's Agenda which includes among others:
American Federation of Labor - Congress of Industrial Organizations
Atlanta Black Agenda
Concerned Black Clergy
Friends of Sweet Auburn
Georgia Association of Black Elected Officials
Georgia Coalition of Black Women
The King Center, Laborers' International Union
MLK March Committee
National Association for the Advancement of Colored People
National Council of Negro Women Southern Christian Leadership Council
SCLC/W.O.M.E.N., Inc.
The Georgia Conservancy
Georgia Interfaith Power and Light
Georgia River Network
Georgia Women's Action for New Directions (WAND)
Georgians for Smart Energy
Georgia Youth for Energy Solutions
Mothers and Others for Clean Air
Ogeechee-Canoochee Riverkeeper
Savannah Riverkeeper
Sierra Club – Georgia Chapter
Southern Alliance for Clean Energy
Southern Energy Network

For the reasons stated below, this permit should be denied.

I. The BACT Emission Limitations in the Permit Are Inadequate.

A. General

The proposed plant will be a supercritical baseload,[1] 850 MW (net) coal-fired unit designed to burn PRB sub-bituminous coal or an alternate blend of 50:50 PRB and eastern bituminous (Illinois #6) coal.[2] The proposed blend is an alternate; the main fuel supply for the unit is PRB. Fuel characteristics are provided below, as taken from the application. 100% Illinois #6 coal is not proposed to be used in the unit.[3]

[1] Application submitted on December 3, 2008, p. 1-6.
[2] Application submitted on December 3, 2008, p. 1-1.
[3] *See* Permit No. 4911-303-0051-P-01-0, Condition 2.11

Table A-2 : Coal Design Data

Item (%) As Received (Wet Basis)	PRB		50/50 Blend		Illinois #6	
	Average	Abuormal	Average	Abnormal	Average	Abnormal
Moisture	29.61	32.05	19.81	21.19	10	10.32
Carbon	49.16	47.66	55.24	53.89	61.32	60.12
Hydrogen	3.43	3.29	4.45	4.10	5.46	4.9
Oxygen	11.31	12.25	9.75	9.77	8.19	7.28
Nitrogen	0.71	0.57	1.55	1.21	2.38	1.85
Sulfur	0.32	0.53	1.72	2.23	3.11	3.93
Ash	5.46	3.65	7.49	7.63	9.52	11.6
HHV (Btu/lb)	8500	8300	9950	9650	11,400	11,000
Trace Analysis (ppm) (Dry Basis)						
Chlorine	100	220	1400	2110	2700	4000
Fluorine	77	181	79	152	80	124
Mercury	0.1	0.25	0.1	0.2	0.09	0.15
Lead	4.63	10.8	7.7	18	10.8	25.3

B. The BACT Analysis Fails to Set Limits For Each Type of Coal.

Although the facility is being designed to burn PRB coal and an alternate blend of 50:50 PRB and Illinois #6 coal, separate BACT limitations have not been set for each type of coal, even though limits are required. A BACT determination must consider clean fuels. Accordingly, 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 permit should set separate BACT limits for each unique fuel, *e.g.*, PRB and 50:50 blend, and then stipulate that the applicable emission limit for any blend of the two shall be determine based on the relative proportions of each. The permit should do so for each pollutant where the parent compound in the coal affects the emission rate such as for SO2, H2SO4, mercury, HF, etc.

C. Comments on Draft Permit (Permit No. 4911-303-0051-P-01-0) Conditions.

The following comments are provided in addition to the more detailed comments on BACT and other issues as will be discussed later.

(a) On Page 2/30 of the permit, the coal unit and its controls are generally described as shown below.

S1	Supercritical Pulverized Coal Fired Boiler – 8300 MMBtu/hr Maximum Heat Input Capacity	LN1 CO2 CO1 CO3 SI1 SI2	Low NOx Burners/Over-fire Air Selective Catalytic Reduction Fabric Filter Baghouse Wet Limestone Scrubber Sorbent Injection for Sulfuric Acid Mist Activated Carbon Injection for Mercury

However, the permit contains no additional engineering design or other description of the coal unit itself, its operating conditions (i.e., steam conditions) or any engineering design or capacity descriptions of the various air pollution controls. These should be provided.

(b) Condition 1.1 states that "[a]t all times, including periods of startup, shutdown, and malfunction, the Permittee shall maintain and operate this source, including associated air pollution control equipment,….". However, the terms startup, shutdown, and malfunction are not defined. They should be.

(c) Condition 2.5 states that "[t]he Permittee shall install and operate, as BACT and MACT for CO and BACT for VOC on Coal Fired Boiler S1, good combustion controls." However, the term "good combustion controls" is not defined and is therefore unenforceable. It should be properly defined.

(d) Condition 2.7 states that "[t]he Permittee shall install and operate, as BACT for H2SO4 on Coal Fired Boiler S1, a Duct Sorbent Injection System." The wet limestone scrubber is also part of the BACT for H2SO4[4] and should be noted in this condition.

(e) Condition 2.9 states that "[t]he Permittee shall install and operate, as BACT and MACT for Mercury on Coal Fired Boiler S1, an Activated Carbon Injection System." However, no details as to the type of activated carbon or its injection rate are specified and they should be.

(f) Condition 2.13(a) states that "[t]he Permittee shall not discharge, or cause the discharge, into the atmosphere, from Coal Fired Boiler S1, any gases which Contain Nitrogen Oxides (NOx) in excess of 0.05 lb/MMBtu on a 30-day rolling average. The numerical limit should be specified to one additional significant digit, namely 0.050 lb/MMBtu. Without that additional significant digit, there may be confusion as to the stringency of this limit. However, please see further comments below on the BACT limit for NOx.

[4] *See* Appendix F, the PM2.5 BACT analysis, dated May 13, 2009.

(g) Condition 2.13(b) states that ". . . [c]ontain Carbon Monoxide (CO) in excess of 0.1 lb/MMBtu on a 30-day rolling average . . . ." The numerical limit should be specified to one additional significant digit, namely 0.10 lb/MMBtu.

D. Proposed NOx Emission Limit is Not BACT.

The NOx BACT limit of 0.05 lb/MMBtu on a 30-day average basis is inadequate. This limit is proposed to be achieved using a combination of low NOx burners and over-fire air to minimize NOx generation in the boiler itself, followed by a Selective Catalytic Reduction unit (SCR) using ammonia injection, for further NOx reduction.

First, neither the application nor the record contains any engineering details on any of these proposed controls. For example, the types of low NOx burners that may be used or even the technologies that comprise low NOx burner designs are not discussed. Furthermore, no details of the over-fire air strategies are provided. For example, will close-coupled or separate over-fire air be used or will both be used in combination. Finally, no details are provided for the SCR such as the type and amount of catalyst. In fact, the description provided likely underestimates the degree of NOx reduction by SCRs.[5] Thus, the selection of BACT was made not on the basis of what these technologies can achieve (i.e., what is achievable, which is the requirement for selecting BACT), but rather what has been achieved in the past.

Modern boilers employ sophisticated burner and combustion management systems that serve to optimize overall combustion conditions and often result in 15-20% NOx reduction in the boiler itself.[6] Yet, the record makes no reference to these technologies and their implementation as part of the BACT for NOx. The analysis is therefore incomplete.

As noted above, the NOx outlet emissions are a function of the NOx level generated in the boiler itself, followed by further reduction in the SCR. As part of the BACT analysis, the applicant and EPD have the obligation to carefully examine each of these steps and their combination in arriving at the lowest achievable emission rate, consistent with the regulatory BACT factors.

Boiler-Out NOx Emissions

The application states, without any support, that the boiler-out NOx level will be 0.22 lb/MMBtu.[7] This is wrong. Numerous PRB-fired coal boilers, currently operating (and operating since the last five years) have much lower boiler out NOx emission rates.

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[5] On page 4-29 of the application, it states that SCR is capable of NOx reduction efficiencies in the range of 70-90%. However, this does not reflect current SCR catalyst capabilities that provide over 90% NOx reduction. The application or the record does not contain any technical basis limiting the upper limit of SCR NOx reduction to 90%.

[6] *See*, for example, *http://www.neuco.net/library/case-studies/default.cfm*.

[7] Application, p. 4-36.

A survey of the EPA's acid rain database[8] shows, for example, lower monthly NOx levels from pulverized coal boilers, including Scherer Units 1-4 (Georgia), Labadie Units 1-4 (Missouri), Rush Island Units 1-2 (Missouri), Meramec Units 1-2 (Missouri), Newton Units 1-2 (Illinois), and Deely Units 1-2 (Texas). Each of these older units burns PRB coals, from various mines in the PRB with likely considerable variability in the coal nitrogen content,[9] and none of these units uses SCR so their NOx emission levels reflect the use of low NOx burners and other strategies (such as OFA) in the boiler itself. Tables containing these data are provided in Exhibit 145 to this letter.

It should also be kept in mind that these units are not subject to stringent NOx permit limits and are therefore not carefully maintaining NOx performance. In other words, likely lower NOx emissions from the boiler are possible, with careful control. Nonetheless, it is obvious from the tables that boiler-out NOx emissions from a new, well controlled and operated PRB coal combustion unit should be no more than 0.10 to 0.15 lb/MMBtu. Within this range, as the data shows, it should be possible to achieve levels closer to or lower than 0.10 lb/MMBtu.

Further support for these levels of boiler-out NOx levels is provided in many recent technical papers that were not discussed in the record and in the development of the BACT limits. Examples of these include:

- G.T. Bielawski, et al., "How Low Can We Go? Controlling Emissions in New Coal Fired Power Plants," U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: "The Mega Symposium," August 20-23, 2001 Chicago, Illinois, U.S.A., Ex. 129. This paper states that "[f]or PRB coal, emission levels down to 0.008 lb/MMBtu NOx, 0.04 lb/MMBtu SO_2, and 0.006 lb/MMBtu particulate with a high level of mercury capture can be achieved."

- A. Kokkinos, et al., "Which is Easier: Reducing NOx from PRB or Bituminous Coal, Power 2003," Ex. 130. This paper discusses retrofits at Georgia Power Company's Plant R.W. Scherer Units 3 and 4 (which burn PRB coal) with separated overfire air. The paper shows that Units 3 and 4 achieved 0.13 lb/MMBtu of NOx after the retrofit, with CO ranging from 114 to 121 ppm (3% O_2 basis). As such, this refutes the contention that low NOx levels can only be achieved with corresponding higher levels of CO (and VOC) emissions.

- Robert Lewis, et al., Summary of Recent Achievements with Low NOx Firing Systems and Highly Reactive PRB and Lignite Coal, Ex. 131: as Low as 0.10 lb NOx/MMBtu; Patrick L. Jennings, Low NOx Firing Systems and PRB Fuel, Ex. 132; Achieving as Low as 0.12 LB NOx/MMBtu, ICAC Forum 2002.

[8] *www.epa.gov/airmarkets*

[9] As such, these NOx levels should also be achievable using the 50:50 blend coals that may be used as the alternate fuel in the proposed unit.

- T. Whitfield, et al., Comparison of NOx Emissions Reductions with PRB and Bituminous Coals in 900 MW Tangentially Fired Boilers, 2003 Mega Symposium, Ex. 133.

- Galen Richards, et al., Development of an Ultra Low NOx Integrated System for Pulverized Coal Fired Power Plants, Ex. 134. "Baseline NOx emissions increased with coal rank 0.49, 0.56, and 0.66 lb/MMBtu for the PRB, hvb, and mvb coals, respectively. The optimized TFS 2000^{TM} firing system achieved NOx emissions of 0.11, 0.15, and 0.22 lb/MMBtu for the 3 fuels for approximately 70-75% reduction over the baseline NOx emissions. Additional NOx reduction of approximately 0.03 lb/MMBtu over the optimized TFS 2000^{TM} levels was achieved using the Ultra-Low NOx firing system technology."

It is striking that the Georgia EPD did not review the technical literature or the performance of even other Georgia units, such as the four Plant Scherer units in assessing the NOx BACT emissions levels.

In any case, there is no support for the contention that the boiler out NOx emissions levels will be as high as 0.22 lb/MMBtu. Rather, it should be closer to 0.10 lb/MMBtu on a 30-day average basis, especially for a new, well-run, baseload unit.

SCR NOx Control Efficiency

If the boiler out NOx is 0.10 lb/MMBtu, the current NOx BACT limit of 0.05 lb/MMBtu means that the SCR control efficiency necessary would only be 50%. If the boiler out NOx was as high as 0.15 lb/MMBtu, the current NOx BACT limit of 0.05 lb/MMBtu would imply an SCR control efficiency of 67%. Both of these are low, even by the assumptions made by the applicant (i.e., efficiency in the range of 70-90%).

Although the application makes vague reference to vendor discussions, there is no data from vendors provided with the Plant Washington permit application to support these low SCR efficiencies or why higher SCR efficiencies cannot be obtained. Modern SCRs routinely achieve NO_x removal efficiencies greater than 90%. Ex. 135.[10] Detailed analyses of EPA's Acid Rain database indicate that "90% removal efficiency was currently being achieved by a significant portion of the coal-fired SCR fleet . . ." Ex. 136,[11] even prior to the time of preparation of the Plant Washington permit application. More than 30 units have achieved greater that 90% NO_x reduction based on 2005 data.

[10] Clayton A. Erickson et al., *Selective Catalytic Reduction System Performance and Reliability Review, The 2006 MEGA Symposium Paper #121*, pages. 1, 15; Clayton A. Erickson et al., *Selective Catalytic Reduction System Performance and Reliability Review Slides*, page 30; Competitive Power College, PowerGen 2005. Selective Catalytic Reduction – From Planning to Operation, 77.

[11] Clayton A. Erickson et al., *Selective Catalytic Reduction System Performance and Reliability Review, The 2006 MEGA Symposium Paper #121*, at 15.

Ex. 136.[12] Ninety% NO_x removal was achieved on 10,000 MW of coal-fired generation in 2004. Ex. 137.[13] Many coal-fired units have been guaranteed to achieve greater than 90% NO_x reduction and are achieving greater than 90% reduction. [14] The McIlvaine reports, one of the sources that EPA states should be considered in a BACT analysis,[15] indicate three of Haldor Topsoe's SCR installations averaged over 95% NO_x reduction during the 2005 ozone season. Ex. 139.[16]

Given this impressive and growing track record with SCR installations, Plant Washington's BACT analysis must demonstrate why the proposed SCR cannot achieve even a minimum of 90% NO_x reduction years from now when SCR retrofits on old subcritical boilers fired on PRB coals are doing better today. The application contains no site-specific or technical factors that would preclude SCRs from achieving at least 90% NOx reduction, even with lower boiler out emissions in the range of 0.10-0.15 lb/MMBtu.

Based on review of the current state of catalyst technology and based on periodic, general and ongoing discussions with SCR and catalyst vendors such as Haldor Topsoe, Cormetech, and others, Plant Washington should be able to obtain at least a 90% removal guarantee for NO_x removal at the SCR.

Suggested NOx BACT Limit

Based on the discussions above, we believe that the NO_x BACT that is appropriate for Plant Washington is 0.02 lb/MMBtu on a 30-day average basis. This level should be readily achievable by (1) either a combination of 0.15 lb/MMBtu from the boiler (as discussed earlier), followed by 87% reduction at the SCR, (2) or a combination of 0.10 lb/MMBtu from the boiler followed by an SCR reduction of 80% or any combination in between. Since actual SCR performance can be better than 90% reduction and actual boiler out performance can be lower than 0.10 lb/MMBtu, a level of 0.02 lb/MMBtu should also provide sufficient compliance margin.

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[12] *Id.* at 1.

[13] Competitive Power College, PowerGen 2005. Selective Catalytic Reduction – From Planning to Operation, 77.

[14] Based on a comparison of ozone season (monthly average for June) and non-ozone season (monthly average for January) 2006 data from EPA's acid rain data base, these include the following: Chesapeake Energy Center Unit 3 (94.51%); John E. Amos Unit 1 (94.27%); John E. Amos Unit 2 (94.06%); Elmer Smith Unit 1 (93.6%); Mount Storm Unit 2 (93.53%); Dallman Unit 2 (93.39%); Dallman Unit 1 (93.24%); New Madrid Unit 1 (93.24%) and New Madrid Unit 2 (93.24).

[15] *Draft 1990 NSR Workshop Manual*, B 12.

[16] McIlvaine Utility e-Alert, No. 798. November 3, 2006. Mr. Nate White of Haldor Topsoe provided the following information: "Topsoe has over 100,000 hours of operating experience on PRB coal. In fact, three Topsoe supplied SCRs achieved the highest NO_x efficiency for all U.S. coal-fired high dust SCRs, averaging over 95% NO_x reduction over the 2005 Ozone season."

Plant Washington's support for its BACT level is erroneous since it relies exclusively on a look-back analysis of actual operating data from existing units (none of which are subject to low permit limits and therefore have no incentive or compulsion to achieve good performance). The selected BACT level is also deficient because it uses the wrong BACT standard (i.e., that it "matches the lowest levels, which have been proposed for BACT for similar projects."[17]). While it may be commendable that the proposed limit is comparable to other proposed low limits, that is not a relevant standard for BACT. BACT is selected on a case-by-case basis, to reflect the maximum degree of emission reduction achievable level, considering the other BACT factors of energy, environmental, and cost impacts. The application does not evaluate, for example, why levels lower than 0.05 lb/MMBtu, such as 0.04, or 0.03, or 0.02 or 0.01 lb/MMBtu are not BACT. These levels are technically feasible. If cost was a factor in failing to select one of these levels, the factor was not part of the BACT discussion.

Inconsistent Applicant Assumptions Regarding Variability

Instead, the application contains erroneous technical analysis pertaining to variability. For example, it contains an analysis noting coal nitrogen variability[18] that is detached from the other assumptions in the application. This analysis notes that the nitrogen content of Wyoming coal can vary from 0.38% to 2.05% relying on the USGS Coal Quality Database. However, its own design basis[19] shows that the PRB coal nitrogen content is 0.71% (normal) and 0.57% (abnormal). The analysis fails to note that the USGS data is derived, in many cases, from the 1970s, from mines and seams that are no longer in production. It also fails to note that since not all seams are uniform, the USGS data do not represent volume-average coal data. In any case, the applicant's analysis in this regard contradicts its own design basis assumption, as noted above.

Flaws in Applicant's Look-Back NOx BACT Analysis

Even relying on the look-back approach to set BACT, the permit fails to set the correct BACT limit. As the application notes, "a total of 25 boilers are achieving levels equal to or below the proposed BACT level (0.05 lb/MMBtu)."[20] Seven units achieved levels that were lower than 0.05 lb/MMBtu for the whole year 2007.[21] At least two similar units (Walter Scott Unit 4 and Colbert Unit 5) achieved emission levels lower than 0.05 lb/MMBtu consistently.[22]

[17] Application, p. 4-38.
[18] Application, p. 4-39.
[19] Application, Appendix A, Table A-2
[20] Application, p. 4-42.
[21] Application, p. 4-45.
[22] Application, p. 4-48.

Trade-off Between Lower NOx and Lower CO/VOC Emissions

Finally, it is incorrect that there is a trade-off between lower NOx and lower CO values.[23] Newer low NOx burners can achieve low NOx as well as low CO values. For example, the DRB-4Z NOx burners developed by Babcock and Wilcox have demonstrated via testing at Wygen Unit 1 that NOx values as low as 0.13 lb/MMBtu were achieved leaving the boiler, while simultaneously providing CO values as low as 100 ppm and very low Loss on Ignition (LOI), which is indicative of low volatile organic compounds (VOC). Wygen Unit 1 burns PRB coal. Ex. 140.[24]

Wygen is not the only example showing that lower NOx can be achieved while having low CO and VOC. Other vendors have provided examples of low NOx and low CO for non-PRB fuels. A different vendor, Foster Wheeler, in a presentation at Power-Gen Asia in September 2006, Ex. 141,[25] also provides examples of testing confirming this fact. Using proper air-fuel biasing technologies, Foster Wheeler was able to achieve very low NOx and CO emissions for different fuels. In one case study discussed in the paper, on a unit burning PRB coal, NOx emissions of 0.11 lb/MMBtu were achieved while keeping CO levels to 5 ppm. Incidentally, unburned carbon levels leaving the boiler were also low. This was demonstrated in 2002.

Averaging Time

Finally we note that the averaging time for the proposed NOx BACT limit of 0.05 lb/MMBtu (30-days) is not as stringent as the proposed NOx limit for the Taylor Energy Center which had a proposed limit of 0.05 lb/MMBtu but on a 24-hour average or the Trimble County Unit 2 which also has a NOx limit of 0.05 lb/MMBtu on a 24-hour average.

E. The Proposed SO2 Emission Limits are not BACT.

The permit for Plant Washington contains three BACT emission limits for SO2, as follows: Condition 2.13(f) limits SO2 to no more than 0.052 lb/MMBtu on a 12-month rolling average; Condition 2.13(g) limits SO2 to no more than 0.069 lb/MMBtu on a 30-day rolling average; and Condition 2.13(h) limits SO2 to no more than 959 lb/hr on a 3-hour rolling average. In addition, it contains a BACT control efficiency limit. Condition 2.14 requires that the wet scrubber SO2 removal efficiency be a minimum of 97.5% over a 20-day average period. In addition, Condition 2.13(p) limits SO2 to no more than 0.08 lb/MMBtu on a 24-hour average basis.

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[23] Application, p. 4-62.

[24] *B&W's AireJet™ Burner for Low NOx Emissions,* 2006 Power-Gen International, November 28-30, 2006, Orlando, Florida, U.S.A.

[25] *Fuel Injection for Pulverized Coal Fired Power Boilers – Automatic Air to Coal Biasing For Lower Overall Emissions*, presented at 2006 Power-Gen Asia, Hong Kong, Hong Kong, September 5-7, 2006.

Explicit Permit Limit When Burning PRB coals

Let us examine the effect of these various permit conditions. First, we consider the limits when the main fuel, namely PRB coal is to be used at the boiler. Using the design coal specifications,[26] the sulfur content of the PRB coal under normal conditions is 0.32%. Using the heating value of 8500 Bu/lb, and assuming that all of the sulfur in the coal is fully converted to SO2 and that none of the SO2 is converted to SO3 nor lost via bottom ash in the boiler (both conservative assumptions), the boiler out SO2 emission rate is 0.75 lb/MMBtu. For these conditions, the annual limit of 0.052 lb/MMBtu implies a SO2 removal rate in the scrubber of 93.1% and the 30-day average limit of 0.069 lb/MMBtu implies a removal rate of 90.8% in the wet FGD. Clearly, the controlling condition is the need to maintain 97.5% removal via condition 2.14. Since this requirement is to be maintained for a 30-day average, it will also be maintained on an annual basis. Using the boiler out emissions level of 0.75 lb/MMBtu and a 97.5% removal rate in the wet scrubber, the outlet emission limit is 0.019 lb/MMBtu. Thus, the permit condition for SO2 should explicitly state that the SO2 limit is 0.019 lb/MMBtu for the 30-day and the annual averaging time periods. This is equivalent to the current permit conditions, when burning the main fuel, i.e., PRB coals in the proposed boiler.

That 0.019 lb/MMBtu should be the explicit permit limit when burning PRB coals is also supported by actual data from the Pleasant Prairie Unit 1, a PRB unit with a wet scrubber. The attached Table (Exhibit 145 to this letter) shows that this unit has been achieving SO2 levels of 0.019 or 0.020 lb/MMBtu consistently throughout 2008 and 2009 on a monthly and annual average basis. Since it is not constrained with such a limit, we believe that its performance can be further improved.

Permit Limit for All Fuels

It is our opinion that this same limit should also apply, regardless of the fuel used at the plant. For the alternate fuel (50:50 blend of PRB and Illinois #6), the blend average normal sulfur content is 1.72% assuming no coal washing (since this assumes that the Illinois #6 coal has a sulfur content of 3.11%) and the SO2 uncontrolled emissions rate from the boiler (again, assuming no loss of SO2 to SO3 or to bottom ash) is 3.46 lb/MMBtu. Thus, meeting a limit of 0.019 lb/MMBtu would require a scrubber SO2 removal efficiency of 99.55%. Assuming no washing of the coal but a loss of 15% SO2 in the boiler to bottom ash, the scrubber efficiency required to meet the 0.019 lb/MMBtu limit would be 99.36%. However, assuming a coal washing sulfur loss of 40% (which is conservative given the relatively high pyritic sulfur content of the bituminous coal), and a 15% loss to bottom ash, the required wet scrubber efficiency to meet the limit of 0.019 lb/MMBtu is 99.14%. This assumes that there is no improvement in the bituminous coal heating value as a result of the washing, which is conservative.

We believe that the wet scrubber can be designed to meet a removal efficiency of 99.14% on a 30-day or longer average basis when using the blended coals, and that the

[26] Application Appendix A, Table A-2.

limit of 0.019 lb/MMBtu can therefore be met. As the application itself suggests, a minimum efficiency that can be expected for these conditions is 98.5%,[27] based on the applicant's analysis of existing scrubber performance, as discussed in the application.

We believe that the 99.14% removal efficiency can be met based on current vendor designs and possibly using additives like dibasic acid, if needed. Ex. 142.[28] Of course the application does not contain any details of the actual wet scrubber design or even the type of wet scrubber that is proposed. So, it is quite likely that the scrubber design itself can accomplish the necessary 99.14% removal efficiency or greater, without need for any additives. In particular, the BACT analysis failed to consider a combination of controls such as a dry scrubber followed by a wet scrubber that would result in greater SO2 removal efficiency. Such configurations have been proposed for Trimble Unit 2 and Cliffside Unit 6.[29] Assuming even a 50% efficiency of the dry scrubber, the combined efficiency (along with 98.5% removal from the wet scrubber) is 99.25%.

There are numerous other examples of scrubbers that have achieved 99% or greater control for SO2. WFGD performance guaranteed to achieve a minimum of 99% efficiency (especially over a long averaging period such as 30 days) is readily possible today and will become increasingly more the norm by the time these plants are built. This is discussed below.

First, over twenty years ago, Mitchell power station Unit 3 (Alleghany Power), a 292-MW generating unit near Pittsburgh, was retrofitted in 1982 with a magnesium-enhanced lime ("MEL") wet FGD system pursuant to a Consent Decree.[30] Data is available for four months during 1983 and 1984 for that unit. Ex. 143. The daily average SO_2 emission rate was 0.009 lbs/MMBtu and the daily average SO_2 removal efficiency was 99.76%. The maximum monthly average during these four months was 0.029 lb/MMBtu, corresponding to a 99.72% SO_2 reduction. Thus, over 99% reduction of SO_2 was being achieved more than two decades ago.

Second, a 2003 paper discussing the actual operating performance of the Chiyoda JBR or CT-121 wet scrubber technology in Japan notes that SO_2 removal efficiency of greater than 99% was achieved for all load levels and that a "[s]table SO_2 removal

[27] Application, p. 4-108.
[28] *See* technical note titled *"Testing INVISTA Dibasic Acid (DBA) in Wet Scrubbers."* The note discusses how addition of 500 ppm DBA increased scrubber removal efficiency from 92% to 97% in one case. We believe that increasing the efficiency from 98.5% (which is the conservative, expected efficiency by the applicant), to 99.14% can be achieved by addition of DBA.
[29] Ex. 168, Cliffside Permit.
[30] *See* EPA Docket EPA-HQ-OAR-2005-0031-0123.

efficiency of over 99 percent" was achieved. Ex. 144.[31] Additionally, Chiyoda's experience list shows at least three instances of 99% removal.[32]

Third, Mitsubishi Heavy Industries ("MHI"), another reputable vendor of wet scrubbers has a design called the High Efficiency Double Contact Flow Scrubber ("DCFS"), which has achieved SO_2 removal efficiencies as high as 99.9%. A presentation on the DCFS scrubber highlights the fact that it can be designed to achieve SO_2 removal efficiencies as high as 99.9% on a unit that burns high sulfur coals without the use of buffer additives. Ex. 146.[33] The manufacturer, MHI, guarantees SO_2 removal of 99.8%.[34] A 2004 paper discussing the DCFS scrubber technology notes that this technology was recently selected at least two years ago by TVA for their Paradise Plant Unit 3, which will start up in early 2007. Ex. 147.[35] This paper also reports on several recent commercial operating successes with this technology "including super high desulfurization performance (*i.e*., 99.9%) with a single absorber."[36] The paper also notes that the COSMO oil Yokkaichi unit is an outstanding example of high SO_2 removal by a single counter current DCFS. Commercial operation at COSMO began in 2003, and the FGD system has achieved a cumulative availability of 100% since startup. The system is designed at 99.5% and operates at 99.9% SO_2 removal efficiency.

Fourth, a different variant of the wet scrubber technology –FLOWPAC – has demonstrated an SO_2 removal efficiency of over 99%. Ex. 148.[37] From November 2002 to March 2003, Karlshamn Unit 3 operated for 2152 continuous hours while firing a heavy fuel with an average sulfur content of 2.4%. The SO_2 emissions during this period were kept to 21 mg/Nm3, which is an SO_2 efficiency of 99.5% with an S efficiency of 99%. During this period the FGD system was 100% available.

Fifth, another vendor, Alstom, recently discussed high efficiency scrubbing on high sulfur fuels. As noted in the paper "[t]o date, the wet flue gas desulfurization system

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[31] *Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant*, Paper #27, by Yasuhiko Shimogama, et al., MEGA Symposium, Washington DC, May 22, 2003.

[32] *http://www.bwe.dk/pdf/ref-11%20FGD.pdf*. Several US companies such as American Electric Power (AEP) are currently installing the Chiyoda JBR scrubber. For example, AEP's Cardinal Units 1 & 2 with JBR scrubbers are scheduled to begin operating in late 2007-early 2008.

[33] *High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market*, Paper No. 135, by Dr. Jonas S. Klingspor, et al, MEGA Symposium, Washington DC, May 22, 2003.

[34] *Id.*

[35] *Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD Paper #33*, by Yoshio Nakayama, et al, MEGA Symposium, Washington DC, August, 2004.

[36] *Id.*

[37] *FLOWPAC – Major WFGD Advance in Flue Gas Contact, Paper # 114*, by Kjell Nolin, MEGA Symposium, Washington, DC, August 2004.

has achieved 100% availability while achieving the plant SO_2 emissions limits throughout the operating duration . . . as indicated . . . the WFGD system has achieved SO_2 removal efficiencies up to 99+% without the use of organic additives." Ex. 149.[38]

Sixth, the Coal Utilization Research Council within the Electric Power Research Institute (CURC/EPRI) concluded in its September 2006 Roadmap that up to 99% SO_2 removal for FGD was commercially available in 2005. Ex. 150.[39] The CURC/EPRI Roadmap also projects removals of up to 99.6% in 2010 and 99.9% in 2015.[40]

In summary, the various permit conditions relating to the BACT limits, namely conditions 2.13(f), 2.13(g), and 2.14 should be replaced by a simple condition limiting the SO2 emissions to 0.019 lb/MMBtu on a 30-day rolling average basis.

Short Term Emissions Limit

As to the 3-hour permit mass limit of 959 lb/hr, at the maximum heat input rate of 8,300 MMBtu/hr, this corresponds to 0.1155 lb/MMBtu. Even with the worst case (i.e., blend coal without coal washing and no loss to bottom ash), this implies that the scrubber would be operating at an efficiency of 96.7% SO2 removal efficiency. Of course the controlled SO2 emission rate would be greater if the actual heat input is lower than 8,300 MMBtu/hr and the scrubber efficiency would be even lower. There is no basis for assuming such a low value of scrubber efficiency. At a minimum, even under startup conditions (when the scrubber would or should be operational before coal is fired into the boiler), the minimum scrubber efficiency should be no lower than 98.5%, as assumed by the applicant. At the maximum heat input rate of 8,300 MMBtu/hr and using blended coals, the controlled emissions rate should be 0.052 lb/MMBtu and the corresponding mass limit should be 430.4 lb/hr. Thus, the 3-hour average SO2 BACT limit of 959 lb/hr in the draft permit fails to reflect BACT for Plant Washington.

F. Proposed PM/PM10 Emission Limits Are Not BACT.

The proposed PM/PM10 permit limits are 0.012 lb/MMBtu for filterable (3-hr rolling average, using CEMS) and 0.018 lb/MMBtu for total (3-hr average). While these limits are comparable to PM/PM10 limits for other facilities, they do not appear to have been set considering what is achievable using current baghouse technology.

The PM/PM_{10} emissions that will be achieved at the proposed unit will depend largely on the design and operation of the fabric filters that will be used. It is well known that, by design and by operation, the fabric filter is not a constant control efficiency device in which its outlet emissions level is simply a fixed fraction of the inlet emissions

[38] *State of the Art Wet FGD System for High-Sulfur Fuels in Florina/Greece*, by G. Catalano, *et al*., Power Gen Europe, 2005.
[39] *CURC/EPRI Technology Roadmap Update, September 20, 2006*, Available at *www.coal.org/PDFs/jointroadmap2006.pdf.*
[40] *Id.*

level. In fact, fabric filters control PM (of any size fraction) emissions generally to the same level of outlet concentration, irrespective of the PM loading at the inlet. This fact has long been recognized by others including EPA.[41] Particulate matter (of various sizes) is captured on the fabric filter as well as the filter cake that develops on the fabric as the device is run over time. The control or removal efficiency achieved depends not only on the inlet emissions levels but also on all of the variables that affect the development, maintenance, morphology, and other characteristics of the filter cake, and the variables associated with the cleaning cycle of the baghouse. In short, the outlet concentration depends more on the design of the fabric filter, the choice of filter materials, and the manner of operation and maintenance of the filters. Yet, given these technical facts, the application or the record does not contain any detailed technical discussion of any of these aspects.

The application notes that the filterable PM limit for Desert Rock is 0.010 lb/MMBtu, using CEMS. Yet, this was rejected simply because the facility has not yet been built at this time. This is not an adequate basis to reject a permit limit determined to be BACT by another agency, in this case the EPA.

Source test data have shown that lower emission levels can be achieved. At least 147 performance tests at coal-fired plants in Florida, as early as May 2004, measured filterable PM/PM_{10} at less than 0.010 lb/MMBtu and 82 recorded PM/PM_{10} emissions less than 0.005 lb/MMBtu. The lowest reported PM/PM_{10} emission rate was 0.0004 lb/MMBtu. Ex. 151.[42]

In light of these discussions, the filterable PM/PM10 limit should be reassessed and based on the actual capabilities of the best types of coated bag filter available. At a minimum, the limit should take into account the numerous low test data results that are provides and other similar data that are available from other states. The total PM/PM10 limit, which includes the condensable (which will all likely be $PM_{2.5}$ in size or smaller) should be reassessed as well to realistically reflect the BACT degree of control of the major condensables, namely H2SO4 and certain VOCs. Please see the BACT discussion for these pollutants.

G. Proposed $PM_{2.5}$ BACT Limits are Incorrect.

First, in addition to the criticisms provided below, we note that although the Plant Washington application[43] contains proposed emission limits for both filterable $PM_{2.5}$ (0.00636 lb/MMBtu) and total $PM_{2.5}$ (0.01236 lb/MMBtu), the permit only contains the total limit.[44] It is not clear why the filterable $PM_{2.5}$ limit, even as proposed by the applicant, is not included in the permit. The Plant Washington permit must contain BACT limits both for filterable and total $PM_{2.5}$.

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[41] *See, e.g.* 73 Fed. Reg. 34076 and 73 Fed. Reg. 34077, June 16, 2008.
[42] Florida Source Tests compilation.
[43] Application, Table F-2, May 13, 2009.
[44] *See* draft permit condition 2.13(e).

Second, to the extent that a significant portion of the condensable $PM_{2.5}$ emissions may be comprised on H2SO4 and condensable VOC emissions, proper BACT controls and limits for those pollutants would also result in lower condensable $PM_{2.5}$ emissions. EPD's proposed emission limits for these pollutants fail to reflect BACT and, therefore, the total $PM_{2.5}$ limit fails to reflect BACT. Please see discussions regarding the improper BACT limits for H2SO4 and VOCs.

Third, the $PM_{2.5}$ BACT analysis notes correctly that NOx emissions are precursors for secondary $PM_{2.5}$ emissions. Therefore, please see previous discussion regarding the inadequacy of the current NOx limit of 0.05 lb/MMBtu as BACT, not just for NOx but also in its role as precursor for secondary $PM_{2.5}$ emissions. Similarly, SO2 emissions are also precursors for secondary $PM_{2.5}$ formation. Therefore, please see previous discussion regarding the inadequacy of the current SO2 limits as BACT, not just for SO2 but also in its role as precursor for secondary $PM_{2.5}$ emissions.

Fourth, the applicant proposed a filterable $PM_{2.5}$ BACT emissions limit using particle size distribution data from AP-42, Table 1.1-6 for the case of coal combustion with a baghouse and its proposed filterable PM10 BACT limit of 0.012 lb/MMBtu. Hence, the filterable portion of $PM_{2.5}$ (as a fraction of PM) is assumed to be 53%. But this is inadequate. The filterable fraction as well as the control efficiency (and therefore the outlet emission rates) of the various sizes of PM, including $PM_{2.5}$, will depend on the type of bag materials that are selected.

The media Ryton, for example, is commonly used in similar applications for PM control. This media removes 99.9% of larger particles, but operates at far lower efficiencies for the smaller particles. Thus, other media must be considered in a $PM_{2.5}$ BACT analysis. Filtration media are available that allow 99.99% of the $PM_{2.5}$ fraction to be removed. These include Daikin's AMIREX^{TM}, PTFE membrane filters,[45] and W.L. Gore's L3650.[46] *See* summary of U.S. EPA's ETV test results in Ex. 41.[47] Thus, the size distribution of filterable $PM_{2.5}$ emissions will be different for different types of bags. Therefore, the applicant should have obtained the particle size distribution data and the baghouse outlet emission rates from baghouse vendors for the various types of bags

[45] *McIlvaine Hot Topic Hour, Filter Media Selection for Coal-Fired Boilers*, September 13, 2007, Presentation by Todd Brown, Daikin America, Inc. Ex. 39. Voice recording available online to subscribers of McIlvaine Power Plant Knowledge System and available for purchase.

[46] USEPA, *ETV Joint Verification Statement, Baghouse Filtration Products*, W.L. Gore & Associates, L3650, Ex. 40 *(http://epa.gov/etv/pubs/600etv06042s.pdf)*.

[47] Fabric Filtration Media are certified by the U.S. EPA Environmental Technology Verification Program using the "Generic Verification Protocol for Baghouse Filtration Products" to Achieve 99.99% Removal of PM2.5.

available, as opposed to just relying on AP-42 to characterize filterable $PM_{2.5}$ BACT emissions for Plant Washington.[48]

The company should have evaluated the various types of bags available in its top-down BACT analysis for $PM_{2.5}$. A bag leak detection system should also be considered as part of the BACT determination.

Other technologies that control $PM_{2.5}$ emission exist and are readily available today. For example, a wet electrostatic precipitator (WESP) placed after a fabric filter would eliminate significant amounts of $PM_{2.5}$ emissions. Ex. 42.[49] The applicant failed to evaluate this combination of controls for $PM_{2.5}$ BACT. EPA and others have recognized that wet ESPs reduce $PM_{2.5}$ emissions. Exs. 43[50] and 44.[51] Indeed, "the WESP is the ultimate device capable of . . . removing ultrafine particles." Ex. 43 at 6-7.

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[48] Curiously (*see* Appendix F, the PM2.5 BACT analysis, dated May 13, 2009), the applicant implies that coated bags are not currently available ("….evaluate coated bags for removal of PM2.5 as they become available in the future."). This is incorrect. Coated bags of many types are currently available and have been for some time. EPA has tested many of these bags with regards to PM2.5 efficiency. *See http://www.epa.gov/nrmrl/std/etv/vt-apc.html#bfp.*

[49] *Report of Expert Witness Hal Taylor, Feasibility of Conducting PM2.5 BACT Analysis for the Highwood Generating Station*, September 2007. *See also* Ex. 42 at 9 ("A wet ESP placed after the fabric filter would eliminate up to 99% of the 130 tons of filterable PM2.5 emissions projected in the Highwood facility air permit. In addition, it would eliminate a similar percentage of the 161 tons of condensable PM that this unit will emit"). Notably, the Wet ESP system "has been in successful commercial operation since 1986."

[50] Moretti et al., *Application of Wet Electrostatic Precipitators to Address Fine Particulate Emission Requirements from Fossil-Fueled Combustors*, ICAC 2005.

[51] "*Evaluation of Potential PM2.5 Reductions by Improving Performance of Control Devices: Conclusions and Recommendations*," Prepared for: U.S. Environmental Protection Agency by E.H. Pechan & Associates, Inc., EPA Contract No. 68-D-00-265 at 23 (September 30, 2005) *available at http://www.epa.gov/pm/measures/pm25_recommend_2007.pdf* (describing Wet ESP as an "innovative control system" that "yield[s] higher PM2.5 emissions reductions than the methods identified to improve existing control device performance"). *See also Candidate Stationary and Area Control Measures*, Chicago PM2.5 Workshop, June 21, 2007, Tim Smith, USEPA at slide 15 (recognizing Wet ESP's as "innovative PM2.5 controls)" *available at http://earth1.epa.gov/ttn/naaqs/pm/presents/control_measures_stationary_and_area-tim_smith.ppt. See also*
CIBO Industrial Emissions Control Technology II Conference, August 2 - 4, 2004 Portland, Maine at 6 (explaining that Wet ESP's are an effective control technology for PM2.5: "There are no moving parts in a wet ESP. The [fine] particles never really reach the electrode and are constantly washed away by the water flow)" *available at* http://www.cibo.org/emissions/2004/summary.pdf.

Examples of facilities using wet ESP technology include: (1) Xcel Energy, Sherburne County, Units 1 and 2;[52] (2) First Energy, Mansfield, Unit 2; (3) Duke Power, Cliffside, Units 6 and 7; [53] (4) AES, Deepwater (operating since 1986), Ex. 42 at 9, 10; and (5) New Brunswick Power, Coleson Cove, Ex. 43 at 6.[54]

In addition to the wet ESP, other options are available to reduce $PM_{2.5}$ emissions. For example, the EPA's Environmental Test Verification (ETV) program recently verified the performance of the "Advanced Hybrid Particulate Collector" (AHPC) system[55] "as providing the lowest filter outlet concentrations for both $PM_{2.5}$ and total mass concentration."[56] The AHPC system was installed at Otter Tail Power's Big Stone 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% 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.[57]

Power4Georgians improperly eliminated this technology as not being available, but it was installed on a full-scale basis at Big Stone and, thus, is a commercially available technology.

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[52] There are 24 WESP modules installed at this plant, 12 each on the two 750-MW units. Ex. 43.

[53] Ex. 168, Cliffside Permit.

[54] In 2002, New Brunswick Power elected to install high-efficiency WESPs following two new limestone-based, wet FGD scrubbers at its 1050-MW Coleson Cove station. Ex. 43 at 6.

[55] 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. *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*

[56] 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*

[57] *See 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*, at 12-13.

A 2005 report prepared for the EPA listed numerous innovative control techniques that yield high $PM_{2.5}$ emissions reductions. Included in the list of controls are: (1) Compact Hybrid Particulate Collector, Ex. 44;[58] (2) Indigo Particle Agglomerator, Ex. 44,[59] 45,[60] 46;[61] (3) Wet ESP, Ex. 47;[62] and (4) Wet Membrane ESP, Ex. 44.[63] Neither Powre4Georgians nor EPD fully evaluated these technologies for limiting $PM_{2.5}$ emissions from Plant Washington.

In summary, Power4Georgian's and EPD's BACT analysis for $PM_{2.5}$ is significantly flawed. Rather than conduct an independent BACT analysis for filterable $PM_{2.5}$, the company and EPD simply relied on the BACT analysis for filterable PM10 and improperly derived a filterable $PM_{2.5}$ limit which EPD wrongfully did not even propose as a BACT emission limit. As we have shown above, there were several $PM_{2.5}$ controls that Power4Georgians and EPD failed to fully evaluate. Further, the proposed total $PM_{2.5}$ BACT limit is based on BACT determinations for VOCs, H_2SO_4, SO_2, and NOx which are also flawed as discussed in these comments. Thus, the proposed emission limits both the filterable and total $PM_{2.5}$ fractions fail to reflect BACT and must be re-analyzed.

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[58] The Compact Hybrid Particulate Collector (COHPAC) is "a pulse jet filter module operated at a very high filtration velocity (air-to-cloth ratio), installed downstream of an ESP. The function of a COHPAC is as a "polishing filter," collecting the particulate (especially fine particulate) that escapes an ESP. A full-scale COHPAC system has been installed at the Gaston power plant near Birmingham, AL (Southern Company, 2004)." Ex. 44 at 26.

[59]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 attaché to each other. These agglomerates enter the precipitator, where they are easily collected due to their larger size." Ex. 44 at 26.

[60] Rodney Truce and others, *Reducing PM2.5 Emissions Using the Indigo Agglomerator*, Mega 2006.

[61] *Indigo Agglomerator: Reducing Particulate Emissions & Reducing, McIlvaine Hot Topic Hour*, November 3, 2006.

[62] *Wheelabrator Air Pollution Control, Inc., PM2.5 Control with Wet Electrostatic Precipitators*, November 2, 2006.

[63] The wet membrane ESP "attempts to avoid problems of water channeling and resulting dry spots than can occur with wet ESPs, and avoiding the higher-cost metals that must be employed to avoid corrosion in a traditional wet ESP. The membranes are made from materials that transport flushing liquid by capillary action effectively removing collected material without spraying (Southern Environmental Corporation, 2004)."

H. Proposed VOC Emission Limit is Not BACT.

The proposed VOC BACT emission limit is 0.0030 lb/MMBtu on a 3-hour average basis. Although it is a slight improvement from the initially proposed limit of 0.0034 lb/MMBtu, our conclusion is that this limit still does not represent BACT for VOCs.

Just like the so-called NOx versus CO trade-off (shown to be incorrect in the previous NOx discussion), the application argues[64] that the VOC limits should be sacrificed in favor of NOx, which is more "aggressive." However, this argument is especially egregious for VOC because many facilities with lower VOC limits also have lower NOx limits than proposed for Plant Washington, *e.g.*, Parish Unit 8; Toquop, Exs. 161A and 161B; Desert Rock, Ex. 162; and Trimble Unit 2.

A well controlled boiler should be able to achieve low VOC and low NOx emission levels. There is no basis for rejecting lower VOC emission limits such as 0.0027 lb/MMBtu for the Intermountain Power Generating Station in Utah, Ex. 160, or the limit of 0.0024 lb/MMBtu for the Santee Cooper Cross Generating Station in South Carolina.

BACT for VOC should be 0.0024 lb/MMBtu on a 3-hour average basis.

I. Proposed H_2SO_4 Emission Limit is Not BACT.

We conclude that the proposed limit of 0.004 lb/MMBtu on a three-hour average basis does not represent BACT for H_2SO_4. Although the application goes through the motions of a top-down BACT analysis, it ultimately plucks the excessively high SAM BACT limit of 0.004 lb/MMBtu out of thin air. While recognizing that " . . . multiple facilities have proposed or achieved emission levels lower than that proposed for Plant Washington, this level (i.e., 0.004 lb/MMBtu) of control was determined to be the maximum amount of control achievable for Plant Washington . . ."[65] This is not carefully supported analysis. It is the exact opposite and an arbitrary selection of BACT.

First, the BACT analysis fails to carefully consider several options to minimize H2SO4 emissions such as: (1) proper (i.e., low conversion) SCR catalysts; (2) a more efficient SO_2 scrubber; (3) air heater additives; and (4) combinations of these methods plus those identified, among others.[66]

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[64] Application, p. 4-73.
[65] Application, p. 134-135
[66] *Draft 1990 NSR Workshop Manual*, p. B.17, "…combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels…"

Second, while that application notes that most of the Illinois #6 coal is washed, the permit does not require that any Illinois #6 coal that will be used as part of the blend be washed.

Third, the application erroneously eliminates circulating dry scrubbers because they have not yet been demonstrated on a coal-fired boiler greater than 250 MW. 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. Ex. 152.[67] Regardless, two 425 MW units in parallel could be used at the facility.

Fourth, Step 3 fails to provide any technical basis for the ranking of the technologies that were selected. The control efficiency of the wet scrubber for H2SO4 will depend on its design and various operational parameters. However, these are not discussed. Similarly, the degree of reduction of H2SO4 using sorbent injection will depend on the type of sorbent selected, the injection rate, the location of injection, etc. These are not discussed either. Thus, there is no demonstration that the emission limit based on the maximum degree of reduction has been selected.

Fifth, the cost-effectiveness analysis provided by the applicant[68] for rejection of wet-ESPs is unsupported. No design information for the wet-ESP provided. Clearly, the cost and expected performance of any control device will depend, at a minimum on its design. Yet, the capital cost of the wet-ESP is assumed to be $290 million and its efficiency is assumed to be 98%. As such, this "analysis" should be set aside until supporting data are provided.

Sixth, as the application itself notes, numerous facilities have limits lower than 0.004 lb/MMBtu. Yet, no reasoned explanation is offered for why this facility cannot meet these lower limits.

Let us examine the likely H2SO4 emissions starting from the sulfur in the fuel. Using a sulfur content of 0.32% in the PRB coal results in an uncontrolled SO2 emissions rate of 0.75 lb/MMBtu from the boiler assuming the heating value of PRB assumed in the design basis. Assuming a 1% conversion of SO2 to SO3 and thence to H2SO4 (as assumed by the applicant),[69] the uncontrolled H2SO4 rate is 0.0092 lb/MMBtu. Assuming a 98% removal efficiency using the combination of sorbent injection and wet FGD controls (which is low and very conservative), the controlled H2SO4 emission rate is 0.00018 lb/MMBtu. Compared to the limit of 0.004 lb/MMBtu, this rate is almost 22 times higher. Starting from the sulfur content of the blend of 50:50 PRB/Illinois #6 coals, the resulting maximum H2SO4 emissions are 0.00085 lb/MMBtu. Again, an efficiency of 98% was conservatively used. Even in this case, the emission limits is almost 5 times higher.

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[67] Sargent & Lundy, *Flue Gas Desulfurization Technology Evaluation*, Prepared for the National Lime Association, March 2007.
[68] Application, p. 4-132.
[69] Application, p. 4-132.

There is simply no basis and no justification for the 0.004 lb/MMBtu BACT emission rate. We recommend a limit of 0.001 lb/MMBtu as being consistent with the BACT standard. As noted, many other facilities have been permitted with similar limits, lower than the applicant's proposed limit of 0.004 lb/MMBtu. The Newmont Mining plant in Nevada has a BACT limit of 0.001 lb/MMBtu. Ex. 163.[70] The NRG Parish Unit 8 in Texas has a limit of 0.0015 lb/MMBtu. The Santee Cooper Cross plant has a limit of 0.0014 lb/MMBtu.

J. The Permit Must Not Exempt Plant Washington from BACT or MACT Limits During Startup and Shutdown.

Condition 7.23.a. of the draft Plant Washington permit provides that:

> "Excess emissions resulting from startup, shutdown, malfunction of any source which occur though ordinary diligence is employed *shall be allowed* provided that …" certain operational conditions are met.

This provision must be modified to clearly state that no exemption from meeting the BACT or MACT limits is allowed. BACT and MACT are defined under the Clean Air Act as "emission limitations" (CAA §169(3), 40 C.F.R. 52.21(b)(12), 63.41) and "emission limitation" is defined as a requirement "which limits the quantity, rate, or concentration of emissions of air pollutants *on a continuous basis*." CAA § 302(k). The EAB has found on numerous occasions that BACT must be met on a continuous basis, and that The U.S. Court of Appeals has also vacated the provision of 40 C.F.R. §63.6(e)(1) allowing for an exemption from emission standards during startup and shutdown.[71]

Specifically, the EAB has concluded that, in order to provide for any different requirements than BACT emission limits for periods of startup, shutdown, and malfunction, state and local permitting authorities must first make a determination available to the public for review and comment, and show that compliance with BACT emission limits during startup, shutdown and malfunction is infeasible. In addition, permitting authorities should, in such cases, establish secondary numerical emission limits or work practice standards that the agency must justify as satisfying BACT. Further, the agency must show that such secondary requirements or standards will provide for compliance with NAAQS and the PSD increments. In cases where a permitting agency would allow the development and submittal of a plan to address emissions during startup, shutdown, and malfunction, the EAB has stated that the contours of plans be noticed and fully subjected to public review and comment as well as to right to appeal such a plan. *See In Re Tallmadge Generating Station*, PSD Appeal No. 02-12, at 24-28 (EAB, May 21,2003)(Ex. 9); *In Re Indeck-Niles Energy Center*, PSD

[70] Newmont Final Permit

[71] *Sierra Club v. Envtl. Prot. Agency*, 551 F.3rd 1019 (D.C. Cir. 2008).

Appeal No. 04-01, at 15-18 (EAB, September 30, 2004) (Ex. 10); *In Re RockGen Energy Center*, 8 E.A.D. 536, at 551-555 (EAB, August 25, 1999) (Ex. 11).

As recently as September 10, 2008, EPA reaffirmed and expounded upon these longstanding legal principles in the context of issuing an order granting, in part, a challenge to a combined PSD and Title V operating permit for a coal-fired power plant in Trimble County, Kentucky. *In the Matter of Louisville Gas and Electric Company, Trimble County, Kentucky, Title V/PSD Permit #V-02–043 Revision 2*, at 9-11 (EPA September 10, 2008) (attached as Ex. B). In EPA's *Trimble* Order, it stated in pertinent part:

> EPA's long held interpretation is that emission limitations in PSD permits apply at all times and may not be waived during periods of startup and shutdown. *See, e.g.*, Memorandum from John B. Rasnic, EPA Stationary Source Compliance Division, to Linda M. Murphy, EPA Region 1, *Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD* (January 28, 1993); *see also Tallmadge Energy Center*, slip op. at 24. A PSD BACT limit must apply at all times, unless the permitting authority determines the need to establish alternative BACT limits for periods of startup or shutdown***, and justifies such limits as part of a complete BACT analysis.*** RockGen Energy Center, 8 E.A.B. at 554. To establish a work practice standard as an alternative BACT limit during such periods, the permitting authority must determine that technological or economic limitations on the application of a measurement methodology to a particular unit would make the imposition of an emissions standard infeasible during such periods.

Id. at 10 (emphasis added). EPA then went on to conclude in the *Trimble* order that the permitting authority had not provided "a sufficient analysis to justify [the] exemption as an alternative BACT limit for periods of startup and shutdown." *Id.*

Therefore, the Plant Washington permit must make clear that no excess emissions are allowed from BACT or MACT emission limits. If EPD intended to allow for any exemptions from meeting BACT limits during periods of startup or shutdown, EPD must show that meeting BACT or MACT during those periods is infeasible, and EPD must propose other emission limitations for public comment that truly reflect BACT or MACT for those periods of operation in the Plant Washington permit

K. The Application Failed To Evaluate IGCC as BACT.

The draft permit improperly failed 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 has been an issue in Georgia played out in the litigation over the Longleaf PSD permit. In that litigation, the Georgia Court of Appeals ruled that the ALJ in the Longleaf matter correctly ruled that EPD did not need to consider IGCC as part of the BACT determination in Longleaf. The Court of Appeals' decision, however, was completely reliant upon a misinterpretation of EPA's "redefining the source" policy. EPA has now clarified the parameters of that policy, and correct application of the policy requires consideration of IGCC as part of the BACT determination in this matter.

By way of background, 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).[72] 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(emphasis added).* 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.

As the Court of Appeals stated in *Longleaf*, EPA policy is that a BACT determination does not require the permitting authority to "redefine the source," but the Court of Appeals' decision failed to explore the proper application of that policy. EPA's Environmental Appeals Board has now filled that void in In *re Desert Rock Energy Company, LLC*, PSD Appeal No. 08-03, 2009, 14 E.A.D. ___, slip op. at 56-78 (EAB Sept. 24, 2009), Ex. 153. In this opinion, the EAB acknowledged that under EPA policy, in setting BACT emission limits, a balance must be struck. On the one hand, the statute mandates that alternative processes and innovative combustion techniques must be considered.[73] On the other hand, the EAB acknowledges the permit applicant's "prerogative to define certain aspects of the proposed facility." *Id*. The EAB went on to conclude that there was no question that EPA had the authority to limit redefinition of the source, but that there was also a real question on how the interpretation should properly be applied." Id. at 62-63.

EPA answered this question by saying that the "redefining the source" policy requires that a permitting agency examine "which design elements are inherent for the applicant's purpose and which design elements 'may be changed to achieve pollutant

[72] S*ee also* Georgia Rules for Air Quality Control 391-3-1-.02(7)(a)(2).
[73] Ex. 153, *Desert Rock* slip op. at 62 (citing CAA § 169(3), 42 U.S.C. § 7479(3).

emissions reductions without disrupting the applicant's ***basic business purpose*** for the proposed facility.'" *Id*. at 64 (quoting *In re Prairie State Generating Co*., PSD Appeal No. 05-05, slip op. at 30 (EAB Aug. 24, 2006) (emphasis added).

In this permitting action, there has been no analysis whether use of IGCC would disrupt the applicant's basic business purpose. In fact, it would not. In *Desert Rock*, "the applicant itself believed that IGCC was consistent with the proposed facility's purpose, objective, or basic design." *Desert Rock*, slip op. at 65. That the applicant in *Desert Rock* should so conclude is not surprising given a review of the legislative history underlying the BACT definition. This history shows 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.
>
> 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.[74]

In *Desert Rock*, the EAB reviewed this history and noted that "[b]ased on Senator Huddleston's clarification and his explanation of the addition of the language 'innovative combustion techniques' to CAA section 169, it appears that the amendments were intended to broaden the definition of BACT so that actions such as the production of gas from coal via gasification would generally be considered in the BACT analysis. While the "redefining the source policy" may play a role in determining on a case-by-case basis what technologies should be considered in a BACT analysis for a facility, as the Seventh Circuit intimated in *Sierra Club v. EPA*, an interpretation that would completely read a statutory term out of the BACT definition would be questionable." *Desert Rock*, slip op. at 77-78, n. 82 (*citing Sierra Club v. EPA*, 499 F.3d 653, 656 (7th Cir. 2007)).

Given the plain language of the Act, the relevant legislative history, and the proper interpretation of EPA's redefining the source policy as reflected in *Desert Rock*, and given the applicant's apparent business purpose, IGCC should be considered as part of any BACT determination for this project.

When IGCC is considered, the applicant should be aware that the U.S. EPA 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. Exs. 154[75] and 155.[76] As such, IGCC plainly fits within the definition of control measures that must be evaluated during the BACT process.

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

[75] *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

[76] *U.S. EPA's Clean Air Gasification Initiative*, Presentation at the Platts IGCC Symposium, June 2, 2005, slide 11

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.

Ex. 156.[77]

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. Ex. 164.[78] 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, Ex. 193;
- Excelsior Energy's 1200 MW (two 600MW plants) Mesaba I & II IGCC plants, Minnesota, Ex. 190;[79] 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. Ex. 165.[80]

[77] NSR Manual, B.6.
[78] U.S. Department of Energy, *Tracking New Coal-Fired Power Plants*, October 10, 2007.
[79] Mesaba Permit Application
[80] 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,[81] 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.[82]

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."[83]

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. The table 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.

[81] Harry Jaeger, *Gasification & IGCC Forum, http://gasification-igcc.blogspot.com/2006/10/hell-bent-on-going-nowhere-october.html.*
[82] Bobby Carmichael, *Tech Could Reduce Coal Facilities' Emissions*, USA Today, December 26, 2007, available at *http://www.stoptoquop.org/?m=200712*
[83] Phil Amick, Gasification Technologies Council, *Experience with Gasification of Low Rank Coals*, June 28, 2006, at 5.

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 (filterable)	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 (filterable) (3-hr ave)	0.0026 (3-hr ave)	0.036 (24-hr ave)	0.006 (24-hr ave)
Erora Cash Creek, Ex. 193	IGCC	0.0246 (24-hr ave)	0.0117 (3-hr ave)	0.0063 (filterable) (3-hr ave)	0.0026 (3-hr ave)	0.036 (24-hr ave)	0.006 (24-hr ave)
Mesaba I & II, Ex. 190[84]	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* below. Ex. 157.[85]

[84] Mesaba Permit Application.

[85] *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	0.634	0.089	0.589	0.541	0.488
CO	0.217	0.880	0.824	0.737	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	7,730	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	0.05 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. Ex. 156.[86]

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

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

Energy Impacts

As shown in the table below, Ex. 157,[87] 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%. Ex. 166.[88] 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%. Ex. 157.[89]

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.[90] 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. Ex. 159.[91]

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

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

plants produce 30-50% less solid waste than PC plants.[92] Lastly, an IGCC plant uses approximately one-half to two-thirds less water than a pulverized coal plant,[93] a significant advantage in Georgia.

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. Ex. 158.[94] If a traditional PC plant was required to achieve the same emissions levels as an IGCC plant, IGCC would achieve cost parity. Ex. 167.[95] 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. Ex. 167.[96] According to the EPA, there are only small differences between the operating costs between the two types of technologies. Ex. 157.[97]

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. Ex. 169.[98] In July 2006, independent power producer Tenaska, Inc. purchased a 50% development-stage interest in the proposed Taylorville Energy Center.[99] 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.[100]

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[92] *Id.* at 1-28.
[93] *Id.* at 2-61.
[94] NPS White Pine comments on draft air permit.
[95] Energy Center of Wisconsin, *IGCC Engineering and Permitting Issues Summary*, April 2006, at 4.
[96] *Id.*
[97] U.S. EPA, *Environmental Footprints and Costs*, at ES-5.
[98] GE Press Release, *GE Unit Makes First Investment in Infrastructure Project Using Gasification Technology*, Jan. 23, 2007.
[99] Tenasksa Press Release, *Tenaska Purchases 50% Development Interest in Illinois Clean Coal Generation Plant*, July 11, 2006, *available at http://www.elyconsultinggroup.com/pressReleases.html*
[100] Elizabeth Souder- DallasNews.com, *NRG Wants a Deal with Texas*, February 15, 2007, available at *http://www.dallasnews.com/sharedcontent/dws/bus/stories/021507dnbuscoal.13fec25.html*

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.

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.

L. There is No BACT Determination for CO_2.

This permit is defective because it contains no BACT emission limits for CO_2. The Georgia Court of Appeals concluded in the *Longleaf* litigation that: "[b]ecause no provisions of the CAA or the Georgia SIP control or limit CO_2emissions, CO_2 is not a pollutant that 'otherwise is subject to regulation under the [CAA].'" Since the Longleaf permit was issued however, regulations issued under the Clean Air Act that control or limit CO_2emissions have been issued.

On June 30, 2009, EPA authorized the state of California to implement its motor vehicle greenhouse gas emission standards pursuant to Section 209(b) of the Clean Air Act, 42 U.S.C. § 7609(b), 74 Fed. Reg. 32,744 (July 8, 2009). As a result, CO_2 was immediately subject to emission limits not only in California, but also in ten of the 14 other states that have imposed these same standards pursuant to their independent authority under Section 177 of the Act, 42 U.S.C. § 7507. Therefore under the Court of Appeals' analysis, carbon dioxide is now "subject to regulation." Accordingly, CO_2 emissions from major emitting facilities are now unambiguously subject to "best available control technology" ("BACT") emission limits. *See* 42 U.S.C. §§ 165(a)(4) & 169(3) (requiring BACT for all pollutants "subject to regulation" under the Act).

California's grams-per-mile standards (the "CO_2 Emission Limits") are effective for model years 2009 through 2016:

> [California's] regulation covers large-volume motor vehicle manufacturers beginning in the 2009 model year, and intermediate and small manufacturers beginning in the 2016 model year and controls greenhouse gas emissions from two categories of new motor vehicles – passenger cars and the lightest trucks (PC and LDT1) and heavier light-duty trucks and medium-duty passenger vehicles (LDT2 and MDPV).

Id. at 32,746. Because Model Year 2010 began on January 2, 2009 (and Model Year 2009 began on January 2, 2008, *see* 40 C.F.R. § 85.2304), the "CO_2 Emission Limits" are currently in effect and govern CO_2 emissions from all new motor vehicle sales and registrations.

The CO_2 Emission Limits are in effect not only in California, but also in 10 other states that have also promulgated these standards for Model Years 2009 or 2010 as follows: Connecticut, Maine, Massachusetts, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington.[101]

Each of these states adopted the CO_2 Emission Limits pursuant to Section 177 of the Clean Air Act, 42 U.S.C. § 7507. Section 177 expressly grants other states the authority to adopt California's vehicle emission standards:

> Section 177 of the Act contains an "opt-in" provision that allows any other state to "adopt and enforce for any model year standards relating to control of emissions from new motor vehicles" if "such standards are identical to the California standards for which a waiver has been granted for such model year" and are adopted "at least two years before commencement of such model year." 42 U.S.C. § 7507.

Am. Auto. Man'fs Assoc. v. Cahill, 152 F.3d 196, 198 (2d Cir. 1998).

[101] Cal. Code Regs. tit. 13, § 1961.1(a); Conn. Agencies Regs. § 22a-174-36b(b)(3); 06-096-127 Me. Code R. § 1(B)(4); 310 Mass. Code Regs. 7.40(2)(a)(6); N.J. Admin. Code § 7:27-29.13; N.Y. Comp. Codes R. & Regs tit. 6, § 218-8.2; Or. Admin. R 340-257-0050(2)(e); 25 Pa. Code 124.412; *see also* 36 Pa. Bull. 7424; 12-031 R.I. Code R. § 37.2.3; 12-031-001 Vt. Code R. § 5-1106(a)(5); Wash. Admin. Code 173-423-090(2). In three more states and the District of Columbia, these standards will come into effect in subsequent model years. Ariz. Admin. Code § R18-2-1801; Md. Code Regs. 26.11.34.03; N.M. Code R. § 20.2.88.101; D.C. Law 17-0151.

States have been exercising their Section 177 authority for almost two decades beginning with New York which adopted California's original Low Emission Vehicle standards in 1992. *Motor Vehicle Mfrs. Assoc. v. New York State Dep't of Envtl. Conservation*, 17 F.3d 521, 529 (2d. Cir. 1994). Not only have states adopted these emission standards under their Section 177 authority, but each state has historically incorporated these standards into their State Implementation Plans ("SIP") under Section 110 of the Act, 42 U.S.C. § 7410. *See, e.g.*, 40 C.F.R. § 52.370(c)(79) (EPA approval of §177-adopted standards as part of Connecticut's SIP); 40 C.F.R. § 52.1020(c)(58) (Maine); 40 C.F.R. § 52.1120(c)(132) (Massachusetts); 40 C.F.R. §52.1570(c)(84)(i)(A) (New Jersey); 40 C.F.R. § 52.2063(c)(141)(i)(C) (Pennsylvania). Once incorporated into a SIP, these requirements become CAA standards, and numerous provisions authorize both EPA and citizens to enforce such SIP requirements, *see e.g.*, 42 U.S.C. § 7413; 42 U.S.C. § 7604(a)(1), (f)(3).[102]

Because the CO_2 Emission Limits are no different than any other vehicle emission standards that states have been adopting and enforcing under the Clean Air Act for decades, it is clear that CO_2 is now "subject to regulation" under the Act. In fact, two federal courts have found that these very CO_2 Emission Limits are indeed federal Clean Air Act standards. In *Central Valley Chrysler-Jeep, Inc. v. Goldstene*, 529 F.Supp.2d 1151, 1165 (E.D. Cal. 2007), the court rejected the notion that even when approved under Section 209 of the Act, the CO_2 Emission Limits "are and remain state regulations and therefore subject to preemption" by the federal Energy Policy and Conservation Act ("EPCA"), stating "[t] he court can discern no legal basis for the proposition that an EPA-promulgated regulation or standard functions any differently than a California-promulgated and EPA-approved standard or regulation." *Id*. at 1173.

Faced with the identical argument, the court in *Green Mountain Chrysler v. Crombie*, 508 F.Supp.2d 295, 350 (D. Vt. 2007) (emphasis added), also rejected the idea that the CO_2 Emission Limits were not federal standards, concluding "that the preemption doctrine does not apply to the interplay between Section 209(b) of the CAA and EPCA, *in essence a claim of conflict between two federal regulatory schemes*."

Because carbon dioxide became "subject to regulation" under the Clean Air Act no later than June 30, 2009, Section 165(a)(4) requires permitting authorities, including Georgia EPD, to establish BACT emission limits for CO_2 emissions from facilities.

[102] Because the CO_2 Emission Limits also provide significant criteria pollutant benefits (74 Fed. Reg. 32,744, 32,758 (July 8, 2009)) California has already included these emissions reductions into its 2007 ozone and PM SIP submittals to EPA. *http://www.arb.ca.gov/planning/sip/2007sip/2007sip.htm.* Other states will presumably now begin doing so as well.

II. Air Dispersion and Mercury Deposition Modeling

A. The Air Dispersion Modeling Results Are Invalid Due to Flaws in the Meteorological Data.

The Draft Permit relies on air dispersion modeling conducted using off-site meteorological data that do not represent conditions at the project site. As a result, the air dispersion modeling results do not accurately predict the project's air quality impacts and are invalid. In particular, the meteorological data used for the Plant Washington dispersion modeling are not representative of the meteorological conditions at the project site near Sandersville for the following reasons: (1) the upper-air data site is located at a significant distance from the project site even though a closer and more representative site exists and should have been chosen; (2) the surface characteristics at the AERMOD measurement site differ significantly from the project site; and (3) Plant Washington's proposed emission point is a 450-foot tall stack and the AERMOD data are based on surface measurements which do not represent meteorological conditions at or near plume height. Use of these non-representative data violate applicable EPA dispersion modeling guidance and skew the modeling results, rendering the modeled predictions inaccurate and invalid. *See* 40 C.F.R. § 51 App. W; *see also* Ex. 170.[103] To correct these errors, Power4Georgians should conduct an on-site meteorological monitoring program to collect representative meteorological data for use and input to the Plant Washington air quality dispersion modeling. Commenters will first outline EPA's position regarding proper air dispersion modeling protocols and then describe the flaws in the meteorological data inputs that undercut Power4Georgian's air dispersion modeling results in greater detail below.

Meteorological Data Must Represent Conditions at the Project Site

To insure that air dispersion modeling results accurately predict the fate and transport of projected air pollution from a new source and its resulting air quality impacts, EPA has made it clear that all meteorological data used for air dispersion modeling must represent conditions at the project site and at all locations that may be affected by a proposed new source. For new source modeling, EPA has determined that "[i]t is important that [meteorological] data be representative of the atmospheric dispersion and climatological conditions at the site of the proposed source or modification, and at locations where the source may have a significant impact on air quality." Ex. 171.[104] "For this reason," EPA directs that "site-specific data are preferable to data collected elsewhere." *Id.*

With specific reference to the AERMOD air dispersion modeling program used in this case, EPA guidelines provide:

[103] U.S. EPA, *AERMOD Implementation Guide* (Rev. March 19, 2009).
[104] EPA, *Draft New Source Review Workshop Manual* (Oct. 1990).

> Regulatory application of AERMOD requires careful consideration of minimum data for input to AERMET. Data representativeness, in the case of AERMOD, means utilizing data of an appropriate type for constructing realistic boundary layer profiles. Of paramount importance is the requirement that all meteorological data used as input to AERMOD must be both laterally and vertically representative of the transport and dispersion within the analysis domain.

40 C.F.R. § 51, App. W § 8.3, Ex. 172.[105]

Several site-specific meteorological and geographic parameters are crucial for assuring the predictive validity of AERMOD dispersion modeling results. Specifically, "measured profiles of wind, temperature, vertical and lateral turbulence may be required . . . to adequately represent the meteorology affecting plume transport and dispersion." *Id.* § A.1. Each of these variables is independently sensitive to the particular meteorological, geographic, and physical conditions of a particular site. EPA has determined that, "since the spatial scope of each variable could be different, representativeness should be judged for each variable separately." *Id*. § 8.3. As an example, EPA notes that "for a variable such as wind direction, the data may need to be collected very near plume height to be adequately representative, whereas, for a variable such as temperature, data from a station several kilometers away from the source may in some cases be considered adequately representative." *Id*. Thus, EPA has concluded that "[s]patial or geographic representativeness is best achieved by collection of all of the needed model input data in close proximity to the actual site of the source(s). Site specific measured data are therefore preferred as model input." *Id*. § 8.3.3.1.

Contrary to EPA's directives, however, the meteorological data inputs for Plant Washington were collected from distant locations that are not representative of the meteorological, geographic, and physical conditions that will determine plume fate and transport at the Plant Washington site. The Plant Washington PSD permit modeling is based on surface meteorological data collected over a five-year period between 1987-1991 from Middle Georgia Regional Airport at Macon, GA, with upper air data collected from Centreville, AL. The Centreville, AL upper air site is approximately 250 miles (400 km) west of Sandersville; the Macon surface weather site is approximately 55 miles (90 km) west of Sandersville. Additionally, despite the fact that the proposed coal-fired boiler stack height at Plant Washington is designed to be 450 feet (137 meters) above grade, the Macon surface meteorological observations were collected at a height of 23 feet (7 meters). As demonstrated next, these spatial and vertical deviations make a difference in this case and translate into meteorological data inputs that do not represent conditions at the Plant Washington site, rendering the air dispersion modeling results inaccurate and invalid.

[105] EPA, *Guideline on Air Quality Models*.

The Upper Air Data Site Does Not Represent Conditions near the Project Site

Obtaining accurate measurements of upper air level atmospheric conditions near the Plant Washington site is critical to determining the fate and transport of the air pollution that the plant will emit if constructed. The AERMOD program Power4Georgian's used in this case relies on the upper air sounding to define the temperature structure of the atmosphere at or near sunrise in order to estimate the convective boundary layer growth during the day. This, in turn, helps predict the effects of weather systems on the fate and transport of the plant's air pollution plumes. Despite the availability of more representative upper air data, however, Power4Georgians' used upper air data taken from the National Weather Station in Centreville, AL, which is located about 250 miles (400 km) from the project site in Sandersville, GA. But these data are not representative of the upper air level meteorology at the Plant Washington site, and the Draft Permit improperly relies on these readings for its AERMOD data inputs.

The large distance between Centreville and the project site in Sandersville introduces the potential for substantial errors in accurately defining the vertical temperature profile. Situations where significant errors may be introduced include periods of active weather where fronts or convective storms propagate from west to east. In these cases, the active weather may lie between Centreville and Sandersville at the time of the morning sounding, causing differences in important air mass characteristics between these two locations. The model will treat the Sandersville as if it lies behind the weather front, when in fact, the Sandersville would lie ahead of the weather front in a completely different air mass. The probability for such an occurrence increases with increasing distance between the project site and the measurement site.

This area of the state also regularly experiences "backdoor" cold fronts, which move into Georgia from the northeast. When these cold fronts slide south, the Appalachian Mountains act as a barrier to movement of the weather front so that these fronts typically do not move further west into Alabama. This also results in sharp differences in air masses between Centreville, AL and Sandersville, GA that in turn introduce errors in defining the vertical temperature profile used by AERMOD.

Instead of using the Centreville, AL upper air sounding to define the vertical temperature profile for the project site, Power4Georgians should have used the upper air sounding from Athens, GA, which would have minimized these errors. Based on the data archives at the National Climatic Data Center ("NCDC"), Athens has upper air data up through 1994, which falls in the 1987-1991 period used for this modeling study. Athens is approximately 75 miles (125 km) from Sandersville and the proximity of Athens compared to Centreville would minimize potential errors introduced by significant air mass differences. Despite this, however, the record does not describe or demonstrate the technical basis for selecting Centerville, AL over Athens, GA to represent the vertical temperature profile at the Plant Washington site.

The Surface Air Data Site Does Not Represent Conditions near the Project Site

Surface characteristics at the data measurement site also influence boundary layer parameter estimates in AERMOD. As with upper air data, obtaining surface characteristics data that closely correlate to the conditions at the project site is vital to the predictive validity of the AERMOD results. EPA's modeling guidance requires that the characteristics of the measurement site should align closely with those of the project site where the data are being applied to insure the representativeness of off-site data. Otherwise, different data (or on-site data) should be used for input to AERMOD.

In this case, Power4Georgians used surface data from Middle Georgia Airport at Macon, GA, ("Macon Airport") to define the surface winds and temperature data for input to AERMOD. The Macon Airport is about 55 miles (90 km) from the proposed plant site at Sandersville, GA, and appears to be the closest available National Weather Service ("NWS") surface station with complete data. As demonstrated below, however, there are important differences in the surface characteristics between the Macon Airport measurement site and the Plant Washington site, which require using different data or on-site measurements in the AERMOD model.

Surface characteristic influences for the AERMOD model are quantified by three parameters: (1) surface albedo; (2) Bowen ratio; and (3) surface roughness length. Comparing the Macon Airport measurement site to the Plant Washington site, reveals important and unresolved differences in each of these three parameters.

Albedo is a measure of the total incident radiation that is reflected by the surface back to the atmosphere without absorption. Lower values mean that most of the radiation is absorbed, warming the near surface layers of the atmosphere, rather than reflected. Higher values mean that most of the incoming radiation is reflected and does not contribute to warming in the lower layers of the atmosphere. Albedo varies by ground cover (*i.e.*, land use) and season. Albedo can increase significantly during the winter, either due to snow on the ground, which is highly reflective, or because vegetation is dormant or leafless, reducing its capacity to absorb incident solar radiation.

The Bowen ratio is the measure of the sensible heat flux to the latent heat flux and is a general indicator of low-level moisture. This parameter affects the planetary boundary layer during convective conditions. Again, this parameter tends to vary by season and by land use. A higher Bowen ratio typifies more arid (dry) conditions.

Tables 1 and 2 describe the recommended albedo and Bowen ratio input data from the *AERMET User's Guide*. Ex. 173.[106] Following the User's Guide, winter conditions apply only during periods of snow cover and sub-freezing temperature. For Sandersville, GA, the "winter" conditions probably do not exist except on rare occasions.

[106] U.S. EPA, *AERMET User's Guide*.

Based on current EPA guidance, Ex. 170,[107] both albedo and Bowen ratio are determined based on a simple unweighted arithmetic mean for a 10 km by 10 km domain centered on the site. This area is roughly approximated by a 3 km diameter circle. Figures 5-3 and 5-4 from the Plant Washington PSD permit application show an aerial photography of the Macon Airport measurement site and the Plant Washington site near Sandersville. The 3 km circle on each figure has been drawn in by the applicant. By using Google Earth, it is possible to compare these figures along with other aerial photographs of the Macon Airport site and the Plant Washington site to assess the surface characteristics of each.

AERMOD allows the user to subdivide the surface characteristics among different sectors where differences exist. In the permit application, each figure has been broken into four sectors. The identified sector differences are more evident at the Macon Airport site than the Plant Washington site, where the land use is more homogeneous.

At the Macon Airport, Sector 1 is predominantly airport property (best described as grasslands), with some buildings associated with airport operations (best described as urban). There is also significant coverage by deciduous trees in the northern part of Sector 1. In Sectors 2 and 3, the coverage is mostly buildings (urban) along with deciduous trees. Sector 4 also has significant coverage from deciduous trees, particularly to the south of the Houston-Bibb County line.

At the Plant Washington site, on the other hand, the land use as determined using aerial photography is fairly uniform, consisting of mostly cultivated lands. There is some minor coverage by deciduous trees along a small creekbed cutting through Sections 1 and 2 and also a small industrial property in Section 4 (since the industrial site has been cleared of vegetation, it may be best described as desert shrublands using the categories in Tables 1 and 2). However, the industrial site does not cover a significant fraction of the sector, so its influence would be minimal.

This review of surface characteristics demonstrates that much of the land use around the airport (urban and deciduous forest) yields a higher albedo and higher Bowen Ratio compared to the cultivated lands that typify the Plant Washington project site (*See* Tables 1 and 2). Therefore, the Macon Airport measurement site is not generally representative of the Plant Washington site in terms of land use and the resulting surface characteristics.

The final characteristic for determining surface characteristic data representativeness is surface roughness, defined as the height at which the mean horizontal wind speed drops to zero. Surface roughness is generally dependent on the height of nearby obstacles to the wind flow, such as trees and buildings, and is approximated by one-tenth of the height of the obstructing objects. Following EPA's AERMOD Implementation Guide, surface roughness is determined using the land use in the nearest 1 kilometer ("km") to the site. Also, these calculations are based on an

[107] U.S. EPA, *AERMOD Implementation Guide* (*Rev. March 19, 2009*).

inverse-weighted geometric mean, meaning that obstacles closer to the site are weighted more heavily in calculating of surface roughness. Table 3 contains recommended values for surface roughness from the *AERMET User's Guide*, based on land use and season.

In the nearest 1 km to the Macon Airport monitoring site, the land characteristics are mostly described by the open grounds of the airport property. The airport buildings appear to be outside the 1 km circle, so these buildings either would not affect surface roughness in Sector 1 or, if they did so, the impact would be felt over only a small part of the sector. There are some deciduous trees in Sector 2, but these trees occur near the 1 km limit such that these effects would not be heavily weighted in the surface roughness determination. However, Sector 4 shows significant growth of deciduous trees close to the monitoring site to the south and the surface roughness in this sector would be dominated by these trees. Overall, the surface roughness for the Macon Airport site is best characterized by "grassland" for Sectors 1, 2, and 3 (with typical surface roughness values ranging from 0.01 to 0.1 meters depending on the season) and by "deciduous trees" in Sector 4 (with typical surface roughness values ranging from 0.8 to 1.3 meters depending on the season).

By contrast, the project site at Sandersville is generally characterized by cultivated lands or low vegetation that appears similar to cultivated lands with crops. There are some deciduous trees covering parts of Sectors 2 and 3, but these are near the 1 km limit and would not weigh heavily in the calculation of surface roughness. Based on the prevailing land uses, the surface roughness for the Plant Washington site is in the range of 0.03 to 0.2 meters, depending on the season.

The Georgia EPD Technical Support Document and the applicant's PSD application contain only a cursory review of the relative surface characteristics between the two sites; the record does not demonstrate a rigorous analysis following EPA's AERMOD Implementation Guide. Table 5-4 in the PSD application contains the applicant's analysis of the relative surface characteristics. The applicant's analysis does not distinguish between different types of vegetation in assessing characteristics for albedo; it does not consider vegetative cover or land use in assessing Bowen ratio; and it appears to extend significantly beyond the recommended 1 km radius when assessing surface roughness. Based on these errors, Power4Georgians' comparison of surface characteristics, as documented by Table 5-4 of the PSD application, violates EPA guidance. *See* Ex. 170.[108]

A proper assessment of surface characteristics following the procedures outlined in the applicable EPA guidelines (*e.g.*, *AERMOD Implementation Guide* (Rev. March 19, 2009)) show that significant differences exist between the Macon Airport site where the meteorological data were collected and the Plant Washington site and near Sandersville. As a result, the Macon Airport surface meteorological data cannot be used for AERMOD modeling of Plant Washington emissions without introducing substantial error and uncertainty into the analysis.

[108] U.S. EPA, *AERMOD Implementation Guide* (Rev. March 19, 2009).

The Measurement Data Do Not Represent Conditions at the Emission Point

As with the upper air and surface data characteristics, the selected meteorological data must represent physical conditions at the actual emission point in order to assure accurate AERMOD predictions. For the Plant Washington modeling, the "vertical representativeness" is very important because the stack height for the coal-fired boiler is significantly higher than the measurement height for the surface meteorological station (450 feet vs. 23 feet).

AERMOD is designed to allow user-input of the vertical profile for winds, temperature, and turbulence parameters based on actual measurements. In this case, however, Power4Georgians relied solely on the Macon Airport surface data, and failed to use the advanced features developed specifically for AERMOD. Although AERMOD can model using only a single measured value to define the vertical profile for the meteorological parameters, without additional measured values to define the vertical profile of winds, temperature, and turbulence, AERMOD must construct a theoretical, idealized vertical profile for these parameters based on similarity theory. But EPA's Modeling Guidelines require use of actual data to define the vertical profile where such data are needed to accurately represent important meteorological variables. Even where not otherwise required, use of actual data to define the vertical profile is preferred and provides increased model accuracy.

The potential errors introduced into AERMOD by the lack of actual measurements in the vertical domain are exacerbated in this case by the tall stacks being simulated for the proposed facility. In this case, the proposed stack height is 450 feet, with plume heights extending significantly above the stack top height. Because emissions from the source in question are distributed across a very large vertical cross-section, the proper characterization of winds, temperature, and turbulence in the vertical domain are critical to an accurate modeling simulation. But this has not been done for the Plant Washington modeling, and the failure to do so creates significant uncertainty in the modeling results. Further, some of the modeling results in this case show impacts that fall within a small percentage of the regulatory threshold (*i.e.*, 24-hour average PM_{10} of 4.951 vs. a significant impact limit of 5.0 micrograms per cubic meter). In light of this small range of deviation from the regulatory threshold, the uncertainties in model results introduced by the selected meteorological data undermine the validity of the regulatory conclusions on which the Draft Permit relies.

EPA has made clear its preference for on-site meteorological data to drive the model input. *See* Ex. 172.[109] For most large emission sources, such as coal-fired power plants with stack heights significantly above ground-level, the emission sources routinely use on-site meteorological data for the PSD permit modeling. Relying only on surface data measurements for modeling major emissions points with stack heights of 450 feet is unusual and improper, principally due to the difficulty of making the necessary regulatory demonstration that surface data are representative of conditions at the emission

[109] 40 C.F.R. § 51, App. W § 8.3 (U.S. EPA, *Guideline on Air Quality Models*).

point. The PSD application and Georgia EPD Technical Support Document describing the AERMOD modeling studies lack any demonstration or discussion of how the selected meteorological data are representative of the vertical profile for expected wind, temperature, and turbulence parameters.

Rather than relying on near ground-level data from the Macon Airport measurement site that has not been shown to duplicate conditions at the source stack height, the Georgia EPD should invoke its authority under the PSD program to require an on-site meteorological monitoring program. On-site measurements of key meteorological parameters should have been collected by Power4Georgians during the initial application process, either using an instrumented tall tower (100-meters) or through a remote sensing device like a Doppler acoustic SODAR. These technologies are widely used to collect data necessary to conduct an accurate and defensible dispersion modeling study for complex sources such as coal-fired power plants. Most other proposed coal-fired power plants undergoing PSD permit review have conducted on-site meteorological measurements, and Georgia EPD should require Power4Georgians to resubmit a revised application reflecting representative meteorological data. In fact, it would constitute clear error to issue a final permit based on AERMOD modeling that violates EPA modeling guidance by not requiring on-site, representative meteorological monitoring.

Therefore, Georgia should reject the Draft Permit and direct Power4Georgians to conduct an on-site monitoring program at the proposed Sandersville site. At the conclusion of the monitoring program, the dispersion modeling studies relied upon by Georgia EPD in issuing the proposed Draft Permit should be re-run and compliance with applicable air quality standards and increments validated using on-site data. All of these activities should be completed before a final permit is issued for the proposed plant.

Conclusions

Power4Georgians has submitted, and the Georgia EPD has relied upon, dispersion modeling conducted using off-site meteorological data that does not meet the various tests for data representativeness required under applicable EPA dispersion modeling guidance. *See* Exs. 170 and 172.[110] The meteorological data used for the Plant Washington dispersion modeling are not representative of the project site near Sandersville for the following reasons: 1) the upper-air data site is located at a significant distance from the project site even though a closer and more representative site exists and should have been chosen; 2) the surface characteristics at the AERMOD measurement site differ significantly from the project site where the modeling data have been applied; and 3) Plant Washington's proposed emission point is a 450 foot-tall stack and the AERMOD data are based on surface measurements which are not representative of meteorological conditions at or near plume height. As a result, the air dispersion modeling results do not accurately predict the project's air quality impacts and are invalid. Compliance with the EPA Air Dispersion Modeling Guidelines, Exs. 170 and

[110] 40 C.F.R. § 51, App. W; and (EPA, *AERMOD Implementation Guide* (Rev. March 19, 2009)).

172,[111] requires an on-site meteorological monitoring program to collect representative meteorological data for use and input to the Plant Washington air quality dispersion modeling.

B. The Draft Permit Improperly Relies on PM_{10} Modeling That Violates EPA Guidelines.

Introduction

The PM_{10} modeling that forms the basis for the Draft Permit under-predicts actual PM_{10} emissions from Plant Washington and does not provide a legitimate basis for the Draft Permit for two major reasons. First, the emissions inventory used in the PM_{10} model fails to account for PM emissions under reasonable "worst-case" scenarios. As a result, the modeled results under-predict PM_{10} impacts attributable to Plant Washington. Second, various parameters selected for the AERMOD model are inconsistent and violate regulatory guidance and sound scientific practice. These inconsistencies and irregularities introduce errors into the analysis that cannot be quantified without correcting the model inventory inputs and running the model in accordance with accepted procedures. These errors are fatal to the validity of the Draft Permit, particularly because the modeled PM_{10} impacts purportedly fall below the significant impact level (SIL) by a razor thin margin, and any deviation would trigger a more comprehensive, cumulative impacts analysis.

The PM_{10} modeling described in the PSD permit application used the AERMOD dispersion model, which is the approved model for this situation based on the U.S. Environmental Protection Agency (EPA) *Air Quality Modeling Guideline*, promulgated at 40 C.F.R. § 51, App. W. Ex. 172.[112] These comments focus on the 24-hour average PM_{10} modeling because the PSD application reports a maximum 24-hour average PM_{10} concentration of 4.951 μ/m^3 ("micrograms per cubic meter"). The regulatory threshold used by the Georgia Environmental Protection Division (EPD) is 5.0 μ/m^3, which represents the SIL that triggers a cumulative analysis of Plant Washington emissions with all other nearby PM_{10} emission sources. The 24-hour PM_{10} concentration listed in the PSD permit application and EPD application review is 99% of the regulatory threshold. This means that even a small error in the AERMOD modeling would alter EPD's regulatory conclusions reached in the PSD permit review.

As the technical review described more fully below demonstrates, the 24-hour PM_{10} concentrations reported for Plant Washington are inaccurate. When the modeling errors documented below are corrected, the resulting PM_{10} impacts from Plant Washington will exceed 5.0 μ/m^3 for 24-hour average PM_{10} concentrations. Therefore, EPD should not issue the PSD permit for Plant Washington until a cumulative PM_{10} modeling analysis is performed for the project area.

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[111] *Id.*

[112] 40 C.F.R. § 51, App. W § 8.3 (U.S. EPA, *Guideline on Air Quality Models*).

Plant Washington's PM_{10} Inventory Does Not Reflect Peak Emissions

The PM_{10} emissions inventory used for the Plant Washington PSD modeling studies contain several errors and omissions that render the inventory unsuitable for a PSD permit analysis. To comply with preconstruction PSD requirements, the emissions inventory must represent the reasonably expected "worst-case" scenario in order to identify the peak daily PM_{10} emissions expected from Plant Washington emission sources. The Plant Washington PM_{10} inventory fails this basic test, as more fully explained below. EPD should direct Power4Georgians to correct any errors in the Plant Washington emissions inventory and then rerun the AERMOD analysis for PM_{10} before a final PSD permit can be issued. Specific problems with the PM_{10} emissions inventory are more fully explained below.

Paved and Unpaved Road Emissions Factors

The Plant Washington calculation for paved and unpaved road emissions relies on data from EPA's AP-42 emissions factor document. For these sources, the PM_{10} emissions are a function of several variables that are then used to calculate an emissions factor in units of pounds per vehicle miles traveled (lb/VMT). The PSD application, however, omits critical emissions data, which makes it impossible to independently verify all of the important data using the information in the PSD application or EPD analysis. As a result, the record does not adequately support important model assumptions, many of which are suspect, or the Draft Permit provisions on which those modeled results are based.

Specifically:

- Mean Vehicle Weight: The AP-42 calculations for both paved and unpaved road emissions use the mean vehicle weight as a variable. This weight is listed in the PSD application as 12.5 tons on paved roads and 50 tons for the unpaved roads. The type of vehicle using these roads is not fully described in the PSD application, but it appears that the unpaved roads will be used for ash hauling to the disposal site. Traffic along the paved roads is not explained in the PSD application. Most importantly, the applicant's data does not demonstrate that the model inputs properly incorporated the weight added by the load carried by the truck, or whether they are based solely on the empty truck weight. The correct application of AP-42 requires that the average weight of the truck be calculated including the truck load where appropriate. For example, if the truck has an empty weight of 25 tons and carries a 50 ton load, then the 50 ton mean weight is appropriate assuming that the travel distances are equal for empty vs. full trucks. In order to support this important model assumption, Power4Georgians must demonstrate in the record all relevant details regarding the mean vehicle weight calculation in order to independently verify the accuracy of the AP-42 unpaved and paved road emissions factor.

- Surface Material Silt Content (Unpaved Roads): The AP-42 calculations for unpaved road PM_{10} emissions uses the silt content of the roadbase as a variable in the emissions equation. Based on data in the PSD permit application, the silt content value used by Plant Washington is 6%. The applicant cites AP-42, Table 11.9-3 (Bulldozers-Coal) as the source of this information. Ex. 174.[113] According to the AP-42 document, however, the source in question (Bulldozers – Coal) actually represents data from bulldozers working an active coal pile. Consequently, the silt content used by Power4Georgians in the PM_{10} emission calculations is actually the silt content for a coal pile and not that for the roadbed of an unpaved road. Furthermore, the applicant's choice of 6% is actually the low end of the range for the AP-42 "Bulldozers – Coal" data. Thus, even if Power4Georgians properly used the "Bulldozers – Coal" silt content table, it misapplied the AP-42 data by selecting a silt content value at the lowest end of the range. The appropriate choice for silt content of the road base would be from AP-42 Table 13.2.2-1, which lists relevant data for a variety of industries. Most of the AP-42 data from Table 13.2.2-1 would suggest that the road base silt content is over 6%. Therefore, Power4Georgians underestimated the unpaved road PM_{10} emissions factor.

- Vehicle Miles Traveled (VMT) Data: Power4Georgians' PM_{10} emissions data specify the VMT based on the road distances and an assumed number of vehicle trips. However, Power4Georgians does not explain how it derived the number of vehicle trips figure. The number of trips should be estimated using the expected volume of materials to be shipped in and out of the facility and the average vehicle load per trip. Additionally, since the modeled PM_{10} emissions are based on the worst-case 24-hour emissions, the number of truck trips should not be annualized, but instead should represent a worst-case day. Power4Georgians, however, does not demonstrate whether the truck traffic VMT estimate is annualized or for a worst-case day. This omission introduces significant potential error in the modeling. For example, if certain activities do not occur on weekends or holidays, then the daily number of truck trips needs to be adjusted upward so that the required annual volume can be delivered on just the operating days. Power4Georgians must document in the record the details of the VMT calculations to allow an independent verification of these data.

Paved Road PM_{10} Emissions Mitigation

To calculate the PM_{10} modeling inventory for Plant Washington PM_{10}, Power4Georgians has assumed a 90% "control efficiency" for dust control from truck traffic on paved roads. The Draft Permit record does not document the proposed emissions controls that will purportedly achieve a 90% reduction in PM_{10}. Instead, the Draft Permit (Condition 2.22) merely requires Power4Georgians to "take all reasonable

[113] EPA, AP-42 Emissions Factors Table 11.9-3.

precautions to prevent fugitive dust from becoming airborne" for a variety of emission sources including roadway particulate sources. Further, Condition 7.17 of the Draft Permit requires Power4Georgians to "develop and implement a Dust Suppression Plan."

The absence of concrete, enforceable permit conditions to achieve a 90% level of dust control renders the Draft Permit unlawful. Attaining 90% control of fugitive dust emissions from paved roadways represents an extremely aggressive emissions mitigation program.[114] Because the Draft Permit does not detail specific control measures that will reliably yield a 90% fugitive dust control level, it is impossible to confirm Power4Georgians' fugitive dust control plan will actually achieve the level of control stated in the Draft Permit. Nevertheless, the PM_{10} dispersion modeling assumes and depends on achieving a 90% level of fugitive dust control. Thus, it is critical that the Draft Permit specify and require the emissions controls that will achieve the 90% control level used in the dispersion modeling. Power4Georgians must describe the specific controls planned for mitigating fugitive dust from paved roadways. These proposed controls should be subject to review by the public to allow an independent assessment of whether the 90% emissions control level can actually be achieved. And, assuming Power4Georgians can demonstrate that a 90% fugitive dust emissions control level can be consistently maintained, the controls that yield those results should be included as enforceable permit conditions.

If, on the other hand, the proposed controls are not capable of achieving a 90% reduction of fugitive dust emissions from paved road surfaces, then Power4Georgians has underestimated the emissions, making unreliable the modeling results which do not demonstrate that the 24-hour PM_{10} impacts will be less than the 5.0 μ/m^3 SIL concentration.

Furthermore, the modeled emissions are required to represent the worst-case 24-hour average emissions. As a result, the frequency and consistent efficacy of the applied mitigation measures for fugitive dust control is critical. If the mitigation actions are not applied with sufficient frequency to achieve a 90% reduction in PM_{10} emissions consistently every day, then Power4Georgians cannot use the 90% control number for the 24-hour PM_{10} modeling. The 24-hour PM_{10} modeling must use the lowest control value achieved by the applicant's fugitive dust control plan on any given day. The record, however, does not demonstrate compliance with this fundamental modeling requirement.

[114] Achieving a 90% dust suppression control efficiency is possible only with the use of chemical dust suppressants. Water suppressants alone are capable of achieving no more than a 50% control efficiency. Ex. 192, Howroyd, George C., U.S. Department of Energy, *Technical Guide for Estimating Fugitive Dust Impacts from Coal Handling Operations,* Table 4-6, Estimated Dust Control Efficiencies for Storage Pile Maintenance and Traffic/Material Handling and Processing Activities, Activity A: Vehicular Traffic Around Storage Piles, at 4-9 (Sept. 1984).

Finally, the AP-42 equation used to calculate paved road emissions uses the road surface silt loading (sL) as a variable. Ex. 175.[115] In the "uncontrolled" equation, Power4Georgians assigned a value of 8.2 grams per square meter to define the silt loading. In the AP-42 equation, PM_{10} emissions are related to sL to the 0.65 power. *Id.* Due to this nonlinear relation, the actual silt loading of the road surface must decrease by substantially more than 90% in order to achieve a 90% reduction in PM_{10} emissions. If a 90% control value is assigned to reflect the applicant's dust mitigation strategy, the "controlled" silt loading calculated using AP-42 equates to 0.12 grams per square meter. *Id.* This corresponds to a reduction of approximately 98.5% from the "uncontrolled" silt loading of the road surface. Such an extraordinarily high level of emissions control is very difficult, if not impossible, to achieve. Conversely, if Power4Georgians' mitigation measures reduce the "silt loading" value by 90% from the uncontrolled level, the PM_{10} emissions control actually equates to 77.6% based on AP-42. *Id.*

Since Power4Georgians has calculated the "controlled" silt loading value using the AP-42 emissions equation, the Draft Permit should require that Power4Georgians sample the paved road surface for "silt content" using the Methods appearing in the AP-42 Appendix to verify that the proposed paved road PM_{10} controls are actually achieving the 90% emissions reduction goal. The sampling frequency for this testing should be sufficiently frequent to provide confidence that the silt loading limit (0.12 grams per square meter) is being achieved for each and every 24-hour period that truck traffic occurs. If the measurements show a silt loading above 0.12 grams per square meter along the paved road surface during any test, then the fugitive dust control program would not meet the required 90% level of PM_{10} control.

The bottom line is the PM_{10} emissions modeled in the AERMOD analysis for paved road emissions are not consistent with the Draft Permit conditions. The paved road emissions input to the model are based on a very aggressive program for reducing fugitive dust that is not reflected in the stringency of the Draft Permit requirements. Either the permit should be corrected to add testing and monitoring to verify that a 90% PM_{10} emissions control is consistently being achieved at this source, or the PM_{10} emissions from the paved roads must be revised upwards to reflect a more realistic control level for the emissions mitigation actually proposed by the applicant. The Draft Permit must require monitoring and testing to verify that the planned fugitive dust controls are effective and achieve the assumed level of control. The recordkeeping requirements in the Draft Permit will not effectively demonstrate whether the fugitive dust control plan achieves the required level of stringency assumed in Power4Georgians' emission inventory calculations.

Inappropriate Application of the AP-42 Precipitation Mitigation Factor

Power4Georgians erroneously applied annual precipitation mitigation factors to estimate 24-hour PM_{10} emissions. The AP-42 emissions factor equations for paved and unpaved road emissions applies a correction factor to account for the effect of

[115] EPA AP-42 Emissions Factors – Paved Roads.

precipitation on PM_{10} emissions. Exs. 175 and 176.[116] For unpaved roads, the equation estimates the number of days with 0.01 inches or greater of precipitation and assumes that no road dust emissions would occur on such days. Ex. 176.[117] The paved road mitigation factor is more complex, but is also based on the number of days in a year with precipitation of 0.01 inches or more. Ex. 175.[118]

However, it is inappropriate to use these AP-42 emissions factor equations to compute 24-hour PM_{10} emissions. The AP-42 calculation is based on the annual occurrence of precipitation. As a result, the precipitation correction factor is inappropriate for use in estimating the PM_{10} emissions over a 24-hour period. Based on the number of precipitation days reported for the Plant Washington site (120 per year), there are also 245 days in each year during which no precipitation occurs with no corresponding emissions mitigation. The 24-hour average PM_{10} modeling is supposed to be based on the peak 24-hour PM_{10} emissions period. Therefore, the emissions inventory for paved and unpaved roads should not include the precipitation correction factor when modeling PM_{10} emissions on a 24-hour basis. This error significantly underestimates the PM_{10} emissions from paved and unpaved roads for the Plant Washington 24-hour modeling.

The Draft Permit Improperly Uses Annualized Emissions

Information for the 24-hour PM_{10} Modeling Analysis

The Plant Washington AERMOD modeling incorrectly uses the same PM_{10} emissions rate for the annual modeling and 24-hour average modeling at several emission sources. The specific sources in question are:

- Transfer Point for PRB Coal (A6, A8)
- Transfer Point for Illinois Basin Coal (A7, A9)
- Limestone Transfer Point (A10)
- Bottom Ash Transfer Point (A3)

The emission calculations for each of the above point sources are expressed as a lb/ton emission factor times the annual production for each point. This is improper. Under normal operating conditions over the course of a year, daily emissions are not equally distributed with the same production and throughput for all 365 days in a calendar year. These emissions should instead be estimated based on the peak daily production for each emissions point. By failing to do so, the Draft Permit, relies on PM_{10} modeling results that underestimate actual peak daily PM_{10} emissions. Because Plant Washington's PM_{10} modeling results fall below EPA's SIL by such a slim margin, even a

[116] EPA AP-42 Emissions Factors – Paved Roads and EPA AP-42 Emissions Factors – Unpaved Roads, respectively.
[117] EPA AP-42 Emissions Factors – Unpaved Roads.
[118] EPA AP-42 Emissions Factors – Paved Roads.

very small error undermines the basis for EPD's regulatory conclusion that PM_{10} concentrations are below the SILs.

The PM_{10} Emissions Data Are Incomplete

Because of the very small compliance margin for the 24-hour PM_{10} concentrations at Plant Washington, it is vitally important that the PM_{10} inventory is accurate and complete. Even minor PM_{10} emission sources from processes normally considered as "insignificant activities" must be included in the PM_{10} modeling analysis because of the razor-thin margin of compliance. Any failure to include minor PM_{10} emissions could invalidate EPD's PM_{10} modeling conclusion.

Power4Georgians' AERMOD modeling, therefore, must consider all PM_{10} emission sources associated with operation of Plant Washington, regardless of emissions magnitude. The Draft Permit depends on Power4Georgians' demonstration of PM_{10} compliance without the need for a more extensive cumulative emissions modeling study, and there is no margin of error in the current modeling.

But Power4Georgians has failed to account for all PM_{10} emission sources. Examples of minor emission sources that may contribute to the 24-hour PM_{10} impacts, but which are not factored into the PM_{10} source modeling inventory, include back-up generators, fire water pumps, and other emergency equipment. Although such equipment does not normally operate for extended periods (except during emergency situations), the associated emissions would occur periodically during testing of the unit. In this case, in particular, emissions associated with any equipment testing should be part of the worst-case 24-hour PM_{10} emissions inventory considered in the Plant Washington modeling. Operation of any emergency equipment for testing should also be limited in the final PSD permit based on the modeling assumptions used (otherwise the PM_{10} model results will be invalid).

Other potential PM_{10} emission sources include the coal stockpiles. In Power4Georgian's PM_{10} inventory, the emissions account for load-in to the stockpiles (via conveyor or other means) along with wind erosion. But there are no emissions associated with material load-out from the stockpiles. Thus, it must be assumed the stockpile load-out emissions are controlled via the baghouse emission points. The Draft Permit, however, does not require these controls. There are no fugitive emissions in the AERMOD model associated with any of the coal handling and transfer operations other than load-in to the stockpile which, to qualify as a valid assumption, would require total enclosure of any material transfers along the conveyor system. The Draft Permit includes no such requirements. The final PSD permit must explicitly require total enclosure of these coal transfer operations and establish a no visible emissions standard for these points as part of the required Best Available Control Technology (BACT) controls.

Additionally, the Plant Washington modeling analysis does not include any fugitive emissions associated with coal stockpile maintenance. This means that no equipment (such as graders or front-end loaders) will ever be used by Plant Washington

for stockpile maintenance or coal handling. If any such emissions are expected by Plant Washington, the associated PM_{10} emissions must be included in the emissions inventory and any associated PM_{10} modeling. These types of emissions are common at locations that have open coal storage piles. Therefore, the final PSD permit must explicitly prohibit use of such equipment for coal handling and stockpile maintenance at Plant Washington unless the associated PM_{10} emissions are disclosed and modeled.

Finally, the Draft Permit lists the inactive stockpiles as having no PM_{10} emissions from wind erosion. The only modeled PM_{10} emissions are associated with loading coal to the inactive piles. Since Power4Georgians has assigned 100% control on wind erosion emissions to the inactive piles, the final PSD permit must establish a no visible emissions standard under the PM_{10} BACT requirements for these sources. If the Power4Georgians' mitigation truly achieves 100% control, no visible emissions should occur at any time from the inactive stockpiles.

Even so, however, at some point, Power4Georgians' certainly will reclaim coal from the inactive stockpiles for short time periods. The PM_{10} emissions associated with reclaiming coal from the inactive piles have not been quantified in the Draft Permit. These types of activities at the inactive stockpiles will produce higher emissions compared to normal operations. The PM_{10} modeling must factor the potential emissions associated with periodic coal reclaim activities on the inactive stockpiles. Otherwise, the Plant Washington PSD permitting analysis is incomplete and inaccurate.

C. AERMOD Modeling of PM_{10} Emissions

In addition to the above-described errors in developing an appropriate PM_{10} emissions inventory, the PM_{10} modeling in this case was applied in a manner that violates AERMOD implementation guidelines and sound scientific practice. Ex. 170.[119] As a result, the modeled predictions are inaccurate and do not form a valid basis for the Plant Washington PSD permitting decision.[120]

Modeling Line Sources with the Volume Source Approach

The Plant Washington AERMOD modeling for paved and unpaved roads violates EPA guidance for modeling of line sources using multiple volume sources. Properly applied, AERMOD modeling using the volume source approach is an appropriate and common technique for modeling line source emissions, such as traffic on paved and unpaved roads. The Plant Washington PM_{10} modeling uses these methods to model both the paved road and unpaved road PM_{10} emissions.

The volume sources used to define the road emissions in the Plant Washington PM_{10} modeling are spaced at intervals of approximately 30.5 meters (100 feet) along the

[119] U.S. EPA, *AERMOD Implementation Guide* (Rev. March 19, 2009).
[120] Although these comments focus on PM_{10} modeling, the findings are also applicable to the AERMOD modeling for other pollutants.

road. The modeling assumes that emissions will occur equally along the road, as all volume sources are assigned the same PM_{10} emissions for a given road segment. This approach, however, does not comply with EPA guidance for modeling of line sources using multiple volume sources. The recommended approach is illustrated in Figure 1-8 of the *Industrial Source Complex (ISC) Model User's Guide – Volume II*.[121] Ex. 177.[122] Since the spacing between individual volume sources is 30.5 meters (100 feet), the implied road width based upon EPA's guidance for "line source represented by separated volume sources" is 15.25 meters (50 feet). But this overstates the true road width for a typical two-lane road. By overestimating the road width, the model dilutes the PM_{10} emissions and, thus, underestimates modeled PM_{10} concentrations.

Additionally, the implied road width calculated from Power4Georgians' volume source spacing does not match the implied road width based on Power4Georgians' choice of the initial sigma-y parameter. The guidance for calculating the initial sigma-y is found in the *AERMOD Model User's Guide,* Table 3-1. Ex. 178.[123] Following this guidance, the initial sigma-y should be the center-to-center distance between volume sources divided by 2.15. *Id.* Based on Power4Georgians' volume source spacing, this would yield an initial sigma-y of 14.19 meters. But Power4Georgians' AERMOD input for initial sigma-y is 4.48 meters. Assuming that Power4Georgians derived this initial sigma-y value, then the implied road width would be 4.82 meters (15.8 feet), which is appropriate for a single lane of traffic, but not for a two-lane road.

Furthermore, Power4Georgians also applied an incorrect initial sigma-z parameter. Power4Georgians' set the initial sigma-z value at 1.7 meters, which following the applicable guidance in the Table 3-1 of the *AERMOD Model User's Guide*, results in an implied volume depth of 3.655 meters (12 feet). *Id.* This appears to be reasonable. But Power4Georgians then selected the PM_{10} source release height at 2.44 meters (8 feet). As a result, the selected release height is above the mid-point of the volume source. The proper modeling practice for a surface-based emission source is to use the mid-point of the volume as the release height, which in this case would generate a release height of 1.83 meters (6 feet). In fact, for a surface-based emission source, more emissions will occur in the lower part of the volume. Thus, the proper release height for grade-level or near grade-level roadway emission sources should be below the mid-point of the volume, not above it. This is significant, because a lower release height would produce higher PM_{10} modeled concentrations.

Instead, by selecting a release height above the mid-point of the volume source, the Plant Washington road dust emissions profile is actually lifted off the ground by 0.61 meters (2 feet). This is totally inappropriate for surface-based emission sources; it violates all technical, scientific, and regulatory protocols.

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[121] Although AERMOD has replaced ISC as the dispersion model of choice, the guidance provided by ISC for representing line sources as multiple volume sources still applies for AERMOD.
[122] EPA, *Industrial Source Complex (ISC) Model User's Guide – Volume II*.
[123] EPA, *AERMOD Model User's Guide,* Table 3-1.

Overall, the volume source parameters Power4Georgians selected for the AERMOD modeling are internally inconsistent and violate established scientific practices and applicable regulatory guidance. These problems introduce an unknown error into the PM_{10} modeling analysis. Given the small margin for compliance (AERMOD predictions are 99% of the significant impact level) and also because road dust emissions appear to be a significant contributor to the modeled PM_{10} concentrations, EPD should direct Power4Georgians to correct the Plant Washington PM_{10} modeling and re-submit AERMOD modeling results prior to issuing a final PSD permit. If the new results increase the predicted PM_{10} concentrations, EPD should require Power4Georgians to conduct a cumulative PM_{10} modeling analysis before issuing a final PSD permit.

The Draft Permit Modeling Violates EPA's *AERMOD Implementation Guide*

The *AERMOD Implementation Guide* contains EPA-recommended procedures for the application of AERMOD in regulatory analyses. Ex. 170.[124] The Plant Washington PM_{10} modeling does not conform to the current EPA guidelines in the *AERMOD Implementation Guide*. Specifically, the *AERMOD Implementation Guide* includes appropriate modeling techniques for terrain-following plumes in sloping terrain. *Id.* For Plant Washington, many of the PM_{10} emission sources are fugitive in nature and are released at or near ground-level—*e.g.*, paved and unpaved roadways. These emissions are the type of "terrain-following" emissions covered by the *AERMOD Implementation Guide*. *Id.*

Under the AERMOD default option, PM_{10} concentration calculations are performed as the weighted sum of two plume states: 1) a horizontal plume state, where the plume elevation is calculated using the release height and plume rise effects; and 2) a terrain-responding plume state where the plume is assumed to be terrain-following. *Id.* According to the *AERMOD Implementation Guide*, for situations such as Plant Washington where the receptor elevations are lower than the base elevation of the source, AERMOD will predict pollutant concentrations that are lower than would be estimated from an otherwise identical flat-terrain situation. *Id.* The flat terrain modeling approach better represents situations with terrain-following plumes. In order to correct for these situations, the *AERMOD Implementation Guide* recommends applying AERMOD's non-default option to assume flat and level terrain. *Id.* But Power4Georgians did not follow this EPA modeling guidance in the Plant Washington PM_{10} modeling.

Based on the Plant Washington AERMOD output files, the worst-case receptor (with a predicted 24-hour average PM_{10} concentration of 4.951 μ/m^3) occurred at a receptor with UTM coordinates of 337337 E by 3660911 N and an elevation of 132.98 meters. This receptor is below the base elevation for all Plant Washington PM_{10} emission sources (all Plant Washington emission sources were modeled as having a base elevation

[124] U.S. EPA, *AERMOD Implementation Guide* (Rev. March 19, 2009).

of 139.3 meters[125]). The *AERMOD Implementation Guide* anticipates these types of scenarios in which the worst-case receptor location is below the base elevation of all PM_{10} emissions sources, and Power4Georgians should have followed the appropriate EPA regulatory guidance, but did not. *Id.* Given the Plant Washington situation, where only some of the emission sources release terrain-following plumes, the correct approach would be to model PM_{10} using both the conventional (default) approach and the non-guideline approach according to the *AERMOD Implementation Guide*. *Id.* EPD should then use the worst-case AERMOD result to define the maximum PM_{10} concentrations.

D. AERMOD Does Not Account for Secondary Particle Formation.

Although AERMOD is the approved EPA regulatory model for near-field (within 50 km) dispersion modeling analyses, AERMOD does not account for secondary particle formation. Based on data in EPD's files, Ex. 179,[126] the secondary $PM_{2.5}$ concentrations associated with the Plant Washington emissions could exceed 4.0 μ/m^3 (24-hour average) in the near-field. In light of the fact that AERMOD predicts primary PM_{10} concentrations at 4.951 μ/m^3, any contribution from secondary particle formation will cause an exceedance of the 5.0 μ/m^3 regulatory threshold. Therefore, EPD should consider the CAMx model results for secondary $PM_{2.5}$ and PM_{10} before issuing a final PSD permit. If modeling all PM_{10} emission sources and including secondary particle formation demonstrates that PM_{10} concentrations will exceed regulatory significance levels, EPD should require Power4Georgians to conduct cumulative impact modeling to include all nearby PM emissions sources.

E. Power4Georgians' PM_{10} Modeling Lacked Sufficient Receptors.

Additionally, Georgia regulations for PSD modeling for PM_{10} and $PM_{2.5}$ specify that receptors must be spaced less than 100 meters apart.[127] Power4Georgians' PM_{10} modeling violated this requirement. The PM_{10} modeling input files includes only 90 fence line receptors. Computing the distance between Power4Georgians' receptor points (336599.6, 3660653) and (337166.2, 3660850), however, results in receptor spacing nearly **600** meters apart.[128] The excessive spacing between receptors dilutes and underestimates PM_{10} impacts. EPD should require Power4Georgians to re-run its PM_{10} modeling using an appropriate number of fence line receptors spaced in accordance with Georgia air dispersion modeling requirements.

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[125] The associated implication from the AERMOD modeling data that the Plant Washington site will be perfectly flat is not verified and is unlikely.

[126] Georgia EPD PowerPoint Presentation, *Plant Washington CAMx Modeling for $PM_{2.5}$ and Ozon*e, *Draft.*

[127] Georgia Department of Natural Resources, *Georgia Air Dispersion Modeling Guidance* (Dec. 1, 2006), available at *http://www.georgiaair.org/airpermit/downloads/sspp/modeling/AirDispModelingGuid_v2.pdf*.

[128] Distance (meters) = $[((337166.2-336599.6)^2) + ((3660850\ 0 - 3660653)^2)]^{1/2}$ = 599.9 meters.

F. Conclusion

Power4Georgians' PM_{10} dispersion modeling suffers from fundamental errors involving the selection of improper PM_{10} emissions data for model input and from basic errors in the application of AERMOD. Additionally, the Plant Washington PM_{10} modeling fails to conform to accepted scientific practice and applicable EPA regulatory guidelines for use of AERMOD. In this case, any modeling error is fatal to the Draft PSD permit. The EPA PM_{10} SIL is 5.0 μ/m^3. The Plant Washington AERMOD dispersion modeling predicts a maximum 24-hour average PM_{10} concentration of 4.951 μ/m^3. Thus, the predicted concentration from AERMOD is 99% of the regulatory significant impact threshold. Correcting the emissions and modeling errors described above would yield a different conclusion regarding compliance with the significant impact threshold for PM_{10}. Given the small compliance margin based on the current Plant Washington PM_{10} modeling analysis, even small errors would alter EPD's regulatory conclusion and all such modeling errors must be corrected before EPD can legitimately render a PSD regulatory decision.

Therefore, EPD should direct Power4Georgians to correct the errors summarized above and provide a revised PM_{10} modeling analysis—which should include a comprehensive cumulative modeling study for PM_{10} emissions including nearby emission sources—for public review and comment before issuing a final PSD permit for Plant Washington.

G. $PM_{2.5}$ Emissions Will Exceed Significant Impact Levels.

The Draft Permit ignores record evidence that Plant Washington's emissions of particulate matter (PM) pollution exceed significant impact levels (SILs) and will cause or exacerbate $PM_{2.5}$ nonattainment. There is no question that Plant Washington's projected emissions of PM pollution trigger full PSD review. The PSD review process for PM require, among other things, air quality modeling to determine if increased ambient PM concentrations due to emissions from the facility will exceed PSD SILs. The applicable SILs for PM are listed in Table 1, below.

Table 1 USEPA Prevention of Significant Deterioration Significant Impact Levels		
Pollutant	Averaging Period	Significant Ambient Impact Level ($\mu g/m^3$)
$PM_{2.5}$	24-hour	1.20
	Annual	0.30
PM_{10}	24-hour	5
	Annual	1

In an effort to demonstrate compliance with this PSD modeling requirement, Power4Georgians used EPA's AERMOD model to determine maximum 24hr and annual PM impacts for Plant Washington. According to the results of the screening model used

to justify the Draft Permit, listed in Table 2 below, the projected $PM_{2.5}$ and PM_{10} concentrations would not exceed the PSD SILs.

Table 2 AERMOD Screening Run Model Results for Plant Washington		
PM 24-hour Results		
Year of Model Run	Maximum $PM_{2.5}$ ($\mu g/m^3$)	Maximum PM_{10} ($\mu g/m^3$)
1987	1.17	3.19
1988	1.08	3.52
1989	1.01	4.57
1990	1.11	2.97
1991	1.10	3.25
PM Annual Results		
Year of Model Run	Maximum $PM_{2.5}$ ($\mu g/m^3$)	Maximum PM_{10} ($\mu g/m^3$)
1987	0.15	0.57
1988	0.14	0.65
1989	0.16	0.71
1990	0.15	0.65
1991	0.15	0.51

But these results do not fully account for Plant Washington's $PM_{2.5}$ impacts and do not provide an adequate basis for the Draft Permit. In fact, the full body of evidence in the record refutes Power4Georgians' claim that Plant Washington's projected $PM_{2.5}$ and PM_{10} concentrations will not exceed the PSD SILs. The record includes a draft PowerPoint presentation by Georgia EPD describing CAMx modeling results for Plant Washington, which demonstrates that $PM_{2.5}$ impacts from Plant Washington will exceed SILs and will cause or exacerbate $PM_{2.5}$ nonattainment problems. Ex. 179.[129] Figures 1, 2, and 3, below, are taken from that presentation. These CAMx modeling results demonstrate that emissions from Plant Washington will produce annual and 24-hour $PM_{2.5}$ increases in large areas that will be greater than PSD SILs, with maximum projected 24-hour $PM_{2.5}$ impacts of 7 $\mu g/m^3$ near the plant.

The Technical Support Document (TSD) prepared by Georgia EPD to support the Draft Permit presents only a limited subset of these data. But the information in the TSD is incomplete and, as a result, mistaken, because it omits important and valid $PM_{2.5}$ modeling that refutes the conclusions that underpin the Draft Permit. The TSD (*See* Table 2, App. E) does not discuss Plant Washington's projected near-field impacts on ambient $PM_{2.5}$ concentrations. Instead, the TSD provides information on $PM_{2.5}$ only for the more remote Federal Reference Method ("FRM") monitoring locations, and then only

[129] Georgia EPD PowerPoint Presentation, *Plant Washington CAMx Modeling for $PM_{2.5}$ and Ozon*e, *Draft.*

for mean annual $PM_{2.5}$ levels—the TSD does not present projected changes in 24-hour $PM_{2.5}$ concentrations.[130]

CAMx modeling results demonstrate that predicted $PM_{2.5}$ increases from Plant Washington exceed EPA's SILs and exacerbate nonattainment problems in existing nonattainment areas. Ex. 179.[131] On September 21, 2007, EPA proposed SILs for average 24-hour $PM_{2.5}$ impacts ranging from 1.2 to 5.0 μ/m^3. Figure 2 from the CAMx modeling presentation demonstrates that modeled 24-hour $PM_{2.5}$ increases from Plant Washington would cause impacts ranging from 1.2 to 2.0 μ/m^3 in Newton and Henry Counties in the Greater Atlanta $PM_{2.5}$ non-attainment area and also a small sliver of Bibb County in the $PM_{2.5}$ non-attainment area near Macon. *Id.* Based on the lower range of the 2007 SILs proposed by EPA, the Plant Washington emissions would be predicted to have a significant impact on $PM_{2.5}$ non-attainment in areas already designated as exceeding the $PM_{2.5}$ NAAQS.

Additionally, according to the readings contained in Georgia's *2007 Georgia Ambient Air Surveillance Report*, Sandersville exceeded the annual mean $PM_{2.5}$ NAAQS for the 3-year average for the periods 2004-06 and 2005-07. The predicted increase in $PM_{2.5}$ attributable to Plant Washington (above 0.4 μ/m^3) would be significant at the lower end of EPA's 2007 proposed annual SIL, which ranges from 0.3 to 1.0 μ/m^3. Based on EPA guidance, if a source has a significant impact at a non-attainment receptor, that impact must be cured either through reductions in emissions at the source in question or from a neighboring source. Despite evidence that Plant Washington will have a significant impact on a non-attainment receptor, however, the Draft Permit does not require additional $PM_{2.5}$ emissions reductions from Plant Washington to cure those impacts, and the record does not demonstrate that additional reductions will be required from neighboring sources.

Moreover, the large maximum 24-hour increase in $PM_{2.5}$ modeled by CAMx in the immediate vicinity of the plant could create an additional $PM_{2.5}$ 24-hour non-attainment area in Sandersville. The current 24-hour standard for $PM_{2.5}$ levels in the ambient air is 35 $\mu g/m^3$. The highest 24-hour $PM_{2.5}$ measurement recorded at Sandersville in 2008 was 29.8 $\mu g/m^3$, which is 5.2 $\mu g/m^3$ below the 35 $\mu g/m^3$standard. Meanwhile, the CAMx modeling results indicate that Plant Washington would contribute up to an additional 7.0 μ g/m^3, thus exceeding the $PM_{2.5}$ NAAQS on high PM days. Ex. 179.[132]

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[130] The TSD's Table 2 data matches the PowerPoint slides for the FRM monitors, corroborating the accuracy of the other results in the PowerPoint slides, including the CAMx modeling results.

[131] Georgia EPD PowerPoint Presentation, *Plant Washington CAMx Modeling for $PM_{2.5}$ and Ozon*e, *Draft.*

[132] Georgia EPD PowerPoint Presentation, *Plant Washington CAMx Modeling for $PM_{2.5}$ and Ozon*e, *Draft.*

But the Draft Permit does not account for these important CAMx modeling results. The Draft Permit ignores CAMx results that show Plant Washington's significant modeled $PM_{2.5}$ impacts on existing and potential nonattainment areas and relies, instead, on AERMOD results. This constitutes error in this case. The discrepancies between the AERMOD and CAMx modeled PM25 impacts result from:

1. Inappropriate meteorological data used in the AERMOD modeling (discussed above); and,

2. The fact that AERMOD does not properly model secondary $PM_{2.5}$ impacts, which are much larger than the primary $PM_{2.5}$ impacts (Figure 3, below).

In light of these discrepancies and the greater predictive values CAMx modeling affords under these circumstances, it would be arbitrary, capricious, and not in accordance with the facts or the law to finalize the Draft Permit, which neither accounts for nor cures the CAMx modeled demonstration that Plant Washington's $PM_{2.5}$ impacts would exceed EPA's SILs and cause or exacerbate existing nonattainment for $PM_{2.5}$ pollution.

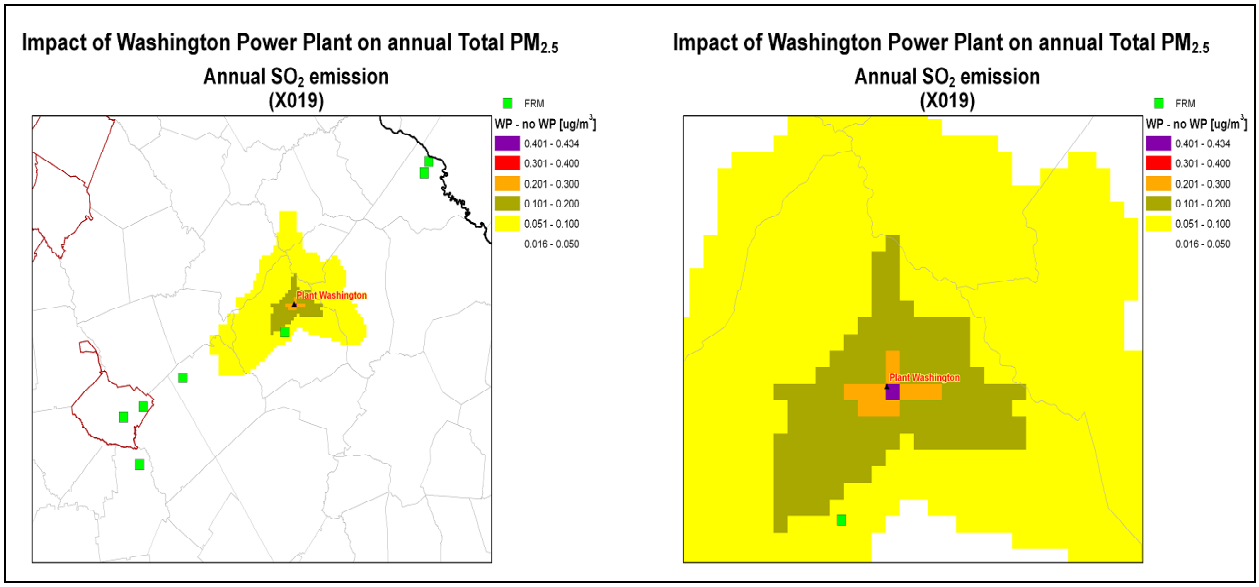

Figure 1: Georgia EPD CAMx regional and near-field modeled annual total (primary & secondary) $PM_{2.5}$ concentration impacts due to Plant Washington.

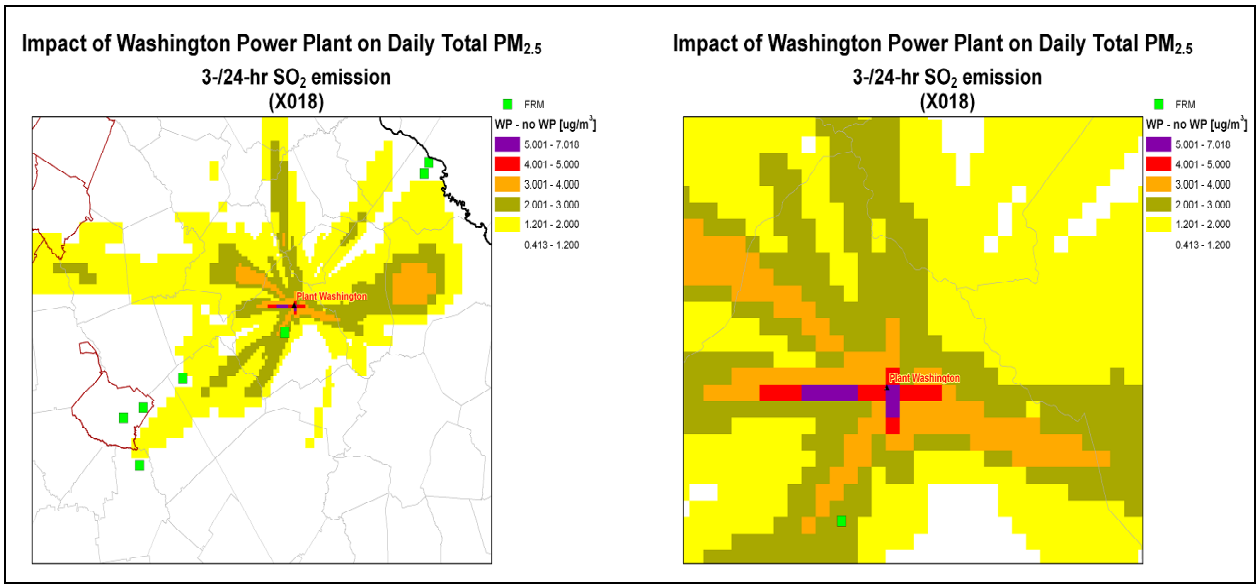

Figure 2: Georgia EPD CAMx regional and near-field modeled maximum 24-hour total (primary & secondary) $PM_{2.5}$ concentration impacts due to Plant Washington.

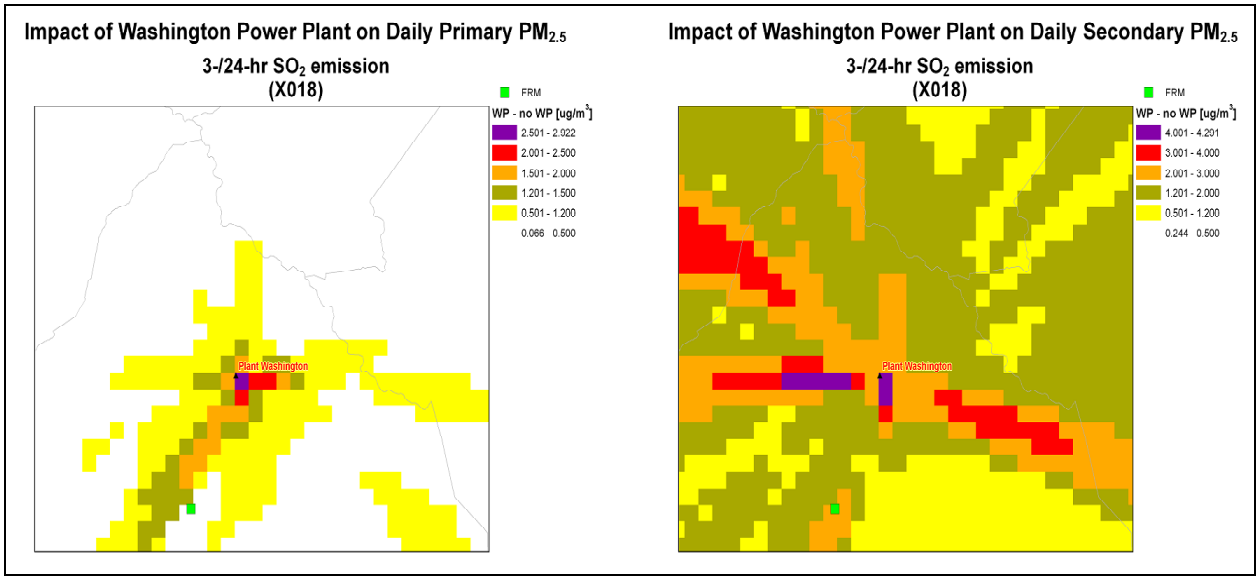

Figure 3: Georgia EPD CAMx modeled near-field maximum 24-hour primary & secondary $PM_{2.5}$ concentration impacts due to Plant Washington.

H. Class I Area Impact Modeling

Introduction

Power4Georgians relied on CALPUFF dispersion modeling to assess the impacts of Plant Washington emission sources to PSD Class I areas located more than 50 km downwind of the proposed source. CALPUFF is the EPA approved long-range transport

dispersion model for receptors located more than 50 kilometers (km) from emissions sources. *See* Ex. 172.[133] In particular, Power4Georgians used CALPUFF modeling to assess the impact of Plant Washington on the following PSD Class I areas located more than 50 km downwind:

- Great Smoky Mountains National Park (NC/TN)
- Cohutta Wilderness ((GA/TN)
- Shining Rock Wilderness (NC)
- Joyce Kilmer/Slickrock Wilderness (NC)
- Cape Romain National Wildlife Refuge (SC)
- Wolf Island National Wildlife Refuge (GA)
- Okefenokee National Wildlife Refuge (GA)

As discussed more fully below, the CALPUFF modeling results reported for Plant Washington are inaccurate and invalid, particularly for visibility impacts to Class I areas. When the modeling errors documented below are corrected, the modeled visibility impacts will exceed the levels reported in the Plant Washington PSD application. As a result, EPD should not finalize the Draft Permit for Plant Washington until the visibility modeling is corrected and the revised results are subject to appropriate agency and public review.

Particle Speciation Profile

Following current Federal Land Manager (FLM) guidance for application of CALPUFF for visibility modeling analyses, the emissions inventory for the visibility modeling should include those particulate matter (PM) species that have significantly greater visibility impact as compared to standard PM emissions. FLM guidance for preparing the "particle speciation" emissions inventory is provided at the National Park Service website. Ex. 180.[134]

For coal-fired boilers like that proposed for Plant Washington, the particle speciation approach requires consideration of both the "filterable" and "condensable" fraction of the PM_{10} emissions. Based on the proposed emission limits from the Draft Permit, Plant Washington will have "filterable" PM_{10} emissions of 0.012 lb/MMBtu and "condensable" PM_{10} emissions of 0.006 lb/MMBtu. Thus, the condensable fraction will account for 33% of the total PM_{10} emissions from Plant Washington.

The filterable fraction of the emissions includes a small fraction of unburned fuel, which should be input to CALPUFF as elemental carbon (EC). EC has a light extinction coefficient of 10, compared to 1 for fine particulate matter (FPM), which means that the EC emissions have visibility impacts that are 10 times greater than FPM for an equal ambient pollutant concentration. The FLM guidance for coal-fired boilers directs sources

[133] 40 C.F.R. § 51, App. W (EPA, *Air Quality Modeling Guideline*).
[134] U.S. National Park Service Guidance on Particulate Matter Speciation, available at: *http://www.nature.nps.gov/air/Permits/ect/ectCoalFiredBoiler.cfm.*

to consider 3.7% of the filterable particulate matter fraction as EC. *Id.* Using the Plant Washington emissions data (0.018 lb/MMBtu total PM, which equates to 18.82 grams per second), the EC emissions following the FLM guidance should be 0.47 grams per second (g/sec). *Id.* But Power4Georgians quantified the EC input at 0.188 g/sec for the Plant Washington modeling. This error greatly under-predicted Plant Washington's Class I visibility impacts.

In the condensable fraction, the PM emissions are broken down into sulfates (with a light extinction coefficient of 3 times f(RH)) and secondary organic aerosols ("SOA") (with a light extinction coefficient of 4). The FLM guidance designates the "inorganic" condensable PM mass as sulfate and the "organic" condensable PM mass as SOA. *Id.* In the absence of other data, the FLM recommends a condensable PM ratio of 80% "inorganic" (sulfate) and 20% "organic" (SOA). *Id.* For the Plant Washington modeling, the sulfate emissions can be estimated directly using the permit limit for sulfuric acid mist (0.004 lb/MMBtu). This limit equates to approximately two-thirds of the condensable PM total. Adjusting for the molecular weight difference between sulfate (SO_4) and sulfuric acid (H_2SO_4), the calculated sulfate emissions are 4.10 g/sec. This modeled value for sulfate appears correct in the Plant Washington CALPUFF modeling.

But Power4Georgians has not included any SOA in the particle speciation profile for Plant Washington. To comply with FLM requirements for Class I modeling, Power4Georgians should have designated all remaining "condensable" PM not accounted for as sulfate as SOA in the visibility modeling. *Id.* The calculated SOA emissions under this approach would be 2.17 g/sec.

Based on the PSD permit application, Plant Washington appears to have justified not modeling SOA emissions based on a comment about the difficulty of modeling SOA made in the VISTAS modeling protocol. This is not an acceptable response. Ignoring the potential adverse visibility effects of these emissions is contrary to the current FLM guidance on visibility modeling. *Id.* Furthermore, the CALPUFF data cited in the revised draft Georgia State Implementation Plan (SIP) for regional haze[135] demonstrates that SOA emissions are routinely included in the Best Available Retrofit Technology (BART) modeling for Georgia emission sources. As such, Power4Georgians' failure to include SOA emissions is contrary to recent Georgia EPD practice for application of CALPUFF in visibility assessments.

Thus, as discussed above, the Plant Washington CALPUFF modeling contains two significant emissions inventory errors—failure to account for properly EC and SOA emissions in the visibility modeling—which result in an underestimation of visibility impacts at nearby Class I PSD areas. The EC and SOA emissions both have more pronounced impact on visibility degradation compared to other pollutants, so properly accounting for these emissions is vital to an accurate assessment of visibility impacts at nearby Class I areas. EPD should require Power4Georgians to correct the PM speciation profile used in the CALPUFF modeling and update the visibility impact modeling for

[135] Available at *www.gaepd.org/Documents/proposed_regional_haze_sip.html.*

nearby Class I areas. Any updated CALPUFF modeling should be made available for public notice and comment prior to issuing a final PSD permit.

Background Ammonia Concentration

Selecting the correct background ammonia concentration is one of the most important inputs to the CALPUFF model. Ex. L;[136] *see* CALPUFF Input Group 11. Power4Georgians selected a background ammonia value of 0.5 parts per billion (ppb) for the Plant Washington modeling. Power4Georgians apparently based this selection on guidance from the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II Report*, Ex. 181, which suggests a background ammonia concentration based on the land use of the area. A value of 0.5 ppb corresponds to areas described as "forested" by IWAQM. *Id.*

Power4Georgians' PSD application did not present any meaningful discussion or other technical information to support its choice of 0.5 ppb as a background level for ammonia. In fact, there is no technical basis to support this choice. Aside from some Class I PSD areas in the Appalachian Mountains, there is no technical basis for selecting predominantly "forested" as the land use for the CALPUFF modeling. A more appropriate choice for the background ammonia concentration using the IWAQM Phase II Report is 10 ppb, which represents areas described as "grasslands." *Id.* Agricultural lands, the land use category that best describes the majority of the Plant Washington CALPUFF modeling domain (particularly to the east and south of the proposed project site), most closely correlates to the "grasslands" designation with a 10 ppb ammonia background value pursuant to IWAQM. *Id.*

Actual ambient ammonia measurements collected in North Carolina also support selecting a higher background level for ammonia. Ex. 182.[137] These measurements indicate that the background ammonia concentration averages between 2 and 15 ppb. The 10 ppb background ammonia suggested by the IWAQM Phase II Report falls in the mid-range of available background ammonia measurements from North Carolina.

As shown above, Power4Georgians should have selected a background ammonia value of 10 ppb, rather than 5 ppb, following the IWAQM Phase II Report. EPD should require Power4Georgians to repeat the CALPUFF modeling using 10 ppb as the appropriate background ammonia level. Using this higher, more representative background ammonia concentration will demonstrate more severe Class I visibility impacts from Plant Washington.

[136] EPA, *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II Report.*
[137] Shendrikar, et al., *Atmospheric Ammonia Monitoring Around Hog Farms Industries in North Carolina*.

Background Visibility Conditions

The visibility modeling analysis also requires specification of the "background" visibility conditions. Use of the correct background visibility is critical because the impact of the project in question is determined as a percentage change in visibility relative to the selected background. Any error in estimating the background concentrations translates into error in assessing the project impacts.

Power4Georgians' selected its visibility background conditions for the CALPUFF visibility modeling from Table V.1-2 of the draft *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Guidance Phase I Report – Revised June 2008* (FLAG 2008). It is important, however, that the "background" concentrations listed in the draft FLAG 2008 guidance are intended for use in the modified IMPROVE equations for calculating the reconstructed aerosol extinction. But the modified IMPROVE equations have not yet been adopted into the Method 2 and Method 6 calculations Power4Georgians used in its CALPUFF modeling. As a result, Power4Georgians has mixed "apples and oranges" in performing the visibility calculations, thereby introducing an unknown rate of error into the analysis.

Instead, EPA's, *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule, EPA-454/B-03-005, September 2003,* Ex. 183, specifies the proper method for establishing the natural background visibility for input to the CALPUFF model. Power4Georgians should have, but did not, follow this EPA guidance to establish the background visibility for the Plant Washington CALPUFF modeling.

Commenters analyzed the effects of this error at the Cape Romain National Wildlife Refuge, which is the Class I area which showed the highest visibility impacts from Plant Washington in the PSD permit application, to determine the direction of the error. For the CALPUFF inputs at Cape Romain, the errors in establishing the background visibility would overestimate the background light extinction compared to the EPA guidance. *Id.* Since Power4Georgians' approach overestimated background visibility, the CALPUFF results underestimated the resulting visibility impacts (measured as a percent change against the background visibility). *Id.*

Additionally, Power4Georgians improperly used the "annual mean" background visibility in the Plant Washington modeling. Instead, Power4Georgians should have used the average for the "cleanest 20% days" to establish the background visibility in order to quantify the visibility impacts on the clearest days in the visibility record where the impacts from other anthropogenic emission sources are minimal. The Clean Air Act's national visibility goal is to remedy existing visibility impairment. When Clean Air Act measures have achieved this goal, background conditions represented by the "cleanest 20% days" will represent actual background conditions. By not assessing the Plant Washington impacts against targeted future conditions that represent a "clean" environment, it is not possible to accurately assess whether or not the Plant Washington emissions will interfere with attaining the Clean Air Act's national visibility goal.

Modeling of Ammonia as a Pollutant

Power4Georgians incorrectly included ammonia as a specific pollutant in the CALPUFF modeling for Plant Washington.[138] Modeling ammonia as a specific pollutant introduces uncertainty into the model's use of ammonia concentrations to establish the ambient background concentration. Under the POSTUTIL program, the user has the option of selecting the modeled ammonia concentrations as the background value for model calculations in lieu of the background data entered through Input Group 11.

Using modeled ammonia concentrations for ambient ammonia background will significantly understate the background ammonia level. This, in turn, will significantly underestimate the resulting sulfate and nitrate formation and result in significant underestimates of the associated visibility and deposition impacts from Plant Washington emissions.

The Plant Washington PSD permit record contains no POSTUTIL files that would allow a reviewer to assess whether or not the CALPUFF visibility modeling was performed using the proper ammonia background levels (the only POSTUTIL files found in the permit record appear related to the deposition modeling). EPD should require Power4Georgians to provide evidence that the CALPUFF modeling calculations used the appropriate ammonia background levels. Otherwise, the CALPUFF modeling results for visibility impacts are suspect. Alternatively, EPD could direct Power4Georgians to provide a case-study where the modeling was performed without the ammonia emissions input in order to verify that the results would not change from the CALPUFF modeling submitted with the PSD permit application.

Visibility Impacts Were Not Evaluated Against the Proper Metric

The record developed in support of the Draft Permit does not contain information required by currently applicable guidance to allow the FLM to make an informed decision regarding Plant Washington's potential air quality impacts to Class I areas. The Federal Land Managers' Air Quality Related Values Workgroup ("FLAG") 2000 Guidance currently applies to major source permitting that may adversely affect air quality related values in Class I areas.[139] Ex. 184.[140]

The FLAG 2000 guidance directs Power4Georgians to provide the CALPUFF visibility results for all modeling periods, indicating the magnitude and frequency of any visibility impacts above established thresholds. *Id.* The guidance further requires that

[138] Ammonia concentrations per se at nearby Class I areas are not of particular interest in assessing air quality related impacts.

[139] The proposed FLAG 2008 guidance is only in draft form and has not yet been issued as a final document. If finalized as proposed, the FLAG 2008 guidance includes the 98th percentile visibility impact. Until finalized, however, the FLAG 2008 guidance should not be used in an effort to support PSD permitting decisions.

[140] *Federal Land Managers' Air Quality Related Values Workgroup 2000 Phase I Report*.

Power4Georgians provide the number of days in each modeling period that may exceed a 5% and 10% threshold for change in light extinction. *Id.* Power4Georgians has not complied with this requirement for Plant Washington. As a result, the record does not afford the appropriate FLMs the mandated opportunity to review the magnitude and frequency of the predicted impacts to ascertain whether the proposed emissions would adversely impact the Class I areas in question.

Instead, the PSD permit application and the accompanying EPD technical review only report data for the 98th percentile visibility impacts for the Class I areas of interest. The 98th percentile represents the eighth-highest visibility impact in each year. The 98th percentile visibility metric was established for the Best Available Retrofit Technology (BART) applicability modeling to assess whether an existing emission source is required to undergo BART review. While appropriate for BART, the 98th percentile visibility metric currently is inappropriate for PSD permitting such as that at issue here.

By reporting only the 98th percentile visibility impact, Power4Georgians has unilaterally decided that potential impacts to visibility that occur up to 2% of the time (seven days per year) is an acceptable level of visibility impact at each Class I area. This approach violates the currently applicable FLAG 2000 visibility modeling guidelines. Power4Georgians must report all visibility impacts to the Class I areas in question in the PSD permit application in order to permit the appropriate FLMs to make informed and technically sound judgments about the potential visibility impacts from the Plant Washington project. The Clean Air Act has reserved to the appropriate FLMs the regulatory authority for judging visibility impacts to Class I areas. Power4Georgians' modeling approach inappropriately usurps this authority.

Conclusions

The CALPUFF modeling for Plant Washington contains several errors that undermine the validity and accuracy of the modeling results, particularly for Class I visibility impacts. EPD should require Power4Georgians to revise and re-run the CALPUFF modeling to: 1) use the FLM-recommended particle speciation profile that properly accounts for EC and SOA emissions; 2) use an appropriate background ammonia concentration (10 ppb) based on the proper land use category for the CALPUFF modeling domain; 3) use the approved EPA methodology to determine the background visibility conditions for the cleanest 20% days; and 4) provide CALPUFF results without explicitly modeling ammonia emissions.

Unless and until the CALPUFF modeling is revised and subjected to additional public comment and review, the CALPUFF results reported in the Plant Washington PSD application are inaccurate and significantly underestimate impacts to Class I areas.

H. Mercury Deposition Modeling

Introduction

Plant Washington is located in close enough proximity to the Upper Ogeechee River Watershed that its air emissions of mercury will cause measurable impairment of water quality in those waters. *See* Exs. 185 and 186.[141] The Ogeechee River to the east of Sandersville is already listed as impaired for mercury; these waters are on the Section 303(d) list due to mercury concentrations in excess of water quality standards and currently are subject to Total Maximum Daily Load limitations for mercury. Exs. 187 and 188.[142] Nevertheless, Power4Georgians did not provide mercury deposition modeling to demonstrate the effects of Plant Washington's emissions on this mercury impaired watershed. This omission undermines the basis for the Draft Permit.

Commenters have independently conducted an analysis and provide with these comments the results of mercury deposition modeling for Plant Washington. The methods, parameters, and results of this modeling, discussed below, demonstrate that Plant Washington will add mercury pollution to the already impaired waters of the Upper Ogeechee River watershed. Based on this fact alone, EPD should deny the Draft Permit and require Power4Georgians to further control and demonstrate that Plant Washington's mercury emissions will not contribute to mercury impairment of the Upper Ogeechee River watershed.

Modeling Approach

Commenters' mercury deposition modeling uses EPA's AERMOD model, and follows the same technical approach outlined in the Trinity Consultants report for Santee Cooper's proposed super-critical pulverized coal-fired power plant along the Pee Dee River near Florence, South Carolina. Ex. 189.[143] Although most of the mercury emitted from coal-fired power plants deposits within 300 kilometers (km) of the emission source, Ex. 185,[144] and the AERMOD model is generally applicable at distances closer than 50 km from the emission source, AERMOD, is listed by EPA as a "guideline" air dispersion model in 40 C.F.R. § 51 App. W, and is an appropriate dispersion model for this modeling exercise. The design parameters of Commenters' model calculations were limited to areas of the Upper Ogeechee River watershed that are within 50 km of the

[141] Ex. P, G. Keeler, M. Landis, G. Norris, E. Christianson, and J. Dvonch, *Sources of Mercury Wet Deposition in Eastern Ohio, USA*, Environ. Sci. Tech. 40, 5874-5881 (2006) ("Steubenville Study"); and Ex. Q, Map of Georgia's Mercury Impaired Waters.
[142] Ex. R, Georgia's 2008 303(d) List; and Ex. S, Ogeechee River TMDL Report.
[143] Trinity Consultants, *Mercury Deposition and Risk: Preliminary Assessment – Santee Cooper, Pee Dee, South Carolina* (July 2008).
[144] G. Keeler, M. Landis, G. Norris, E. Christianson, and J. Dvonch, *Sources of Mercury Wet Deposition in Eastern Ohio, USA*, Environ. Sci. Tech. 40, 5874-5881 (2006) ("Steubenville Study").

proposed Plant Washington site. This covers approximately 70% of the watershed area. Ex. 186.[145]

Modeling receptors were placed on a Cartesian grid within the boundaries of the Upper Ogeechee River watershed at a horizontal spacing of 2 km. Receptor elevations were determined using the AERMAP processor, which is part of EPA's AERMOD modeling system, and digital elevation ("DEM") files for 7.5 degree quadrangles.[146]

Commenters used meteorological data consisting of five years (1987-1991) of surface weather observations collected by the National Weather Service (NWS) at the Middle Georgia Airport located near Macon, GA, coupled with upper air sounding data from the NWS site at Centreville, AL. Power4Georgians used these same data for the Plant Washington PSD permit modeling.

Mercury Emissions Information

Commenters based mercury emissions inputs on the data contained in the Plant Washington PSD permit calculations. Based on these figures, the total mercury emissions for Plant Washington are estimated at 128 lb/year (0.00184 grams/sec).

Mercury speciation plays an important role in deposition modeling. Coal-fired boilers emit three species of mercury:

- Gaseous elemental mercury – Hg(0) Elemental
- Reactive gaseous mercury – Hg(II) RGM
- Particulate mercury – Hg(p)

Mercury emissions speciation fractions depend on a number of factors including the type of coal being combusted and the pollution control systems in place at the coal-fired boiler. The Pee Dee Plant in South Carolina is similar in many respects to the proposed Plant Washington facility (super-critical pulverized coal-fired boilers with wet flue gas desulfurization), so Commenters used the speciation data from the Trinity Consultants report, Ex. T, as listed below.

Hg(particulate)	Hg(II) RGM	Hg(0) Elemental
0.36%	20.06%	79.58%

For the Plant Washington deposition modeling, Commenters simplified the mercury emissions profile to 80% Hg(0) Elemental and 20% Hg(II) RGM. Commenters did not separately consider particulate mercury in the analysis due to the small quantity of emissions.

[145] Map of Georgia's Mercury Impaired Waters.
[146] These files are available for download at *http://www.webgis.com.*

The emissions and other plant data used in the Plant Washington mercury deposition modeling are summarized below.

Parameter	Main Stack	Auxiliary Boiler
Stack Height (m)	137.16	27.43
Stack Diameter (m)	9.14	1.52
Stack Velocity (m/sec)	18.55	19.8
Stack Temperature (deg K)	333	408
Hg(II) RGM Emissions (g/sec)	3.51E-4	1.82E-5
Hg(0) Elemental Emissions (g/sec)	1.39E-3	7.22E-5

Deposition Parameters

The AERMOD deposition calculations require data for various physiochemical parameters, described in the table below.

Deposition Parameter	Hg(II) - RGM	Hg(0) – Elemental
Diffusivity in Air (Da), cm^2/sec	0.06	0.07
Diffusivity in Water (Dw), cm_2/sec	5.20E-06	3.00E-05
Cuticular Resistance (s/cm)	1.00E+05	1.00E+05
Henry's Law Constant (H), Pa-m^3/mol	7.19E-05	1.50E+02

The above data match those used in the Trinity Consultants report for the Pee Dee Plant in South Carolina. Ex. T.

Gaseous deposition is also a function of the available surface area for uptake of the pollutant in question. AERMOD defines the important parameters in terms of a seasonal vegetation category, which can vary by month. The inputs for the Plant Washington modeling are summarized below.

Month	Seasonal Category	Seasonal Code
January	Late Autumn after frost and harvest, or winter with no snow	3
February	Late Autumn after frost and harvest, or winter with no snow	3
March	Transitional Spring (partial green coverage, short annuals)	4
April	Transitional Spring (partial green coverage, short annuals)	4
May	Midsummer with lush vegetation	1
June	Midsummer with lush vegetation	1
July	Midsummer with lush vegetation	1
August	Midsummer with lush vegetation	1

September	Midsummer with lush vegetation	1
October	Autumn with unharvested cropland	2
November	Autumn with unharvested cropland	2
December	Late Autumn after frost and harvest, or winter with no snow	3

Finally, land use affects gaseous deposition by defining (among other things) the leaf area index (LAI), which is the ratio of leaf surface area divided by the ground surface area. In the AERMOD model, the land use category can vary by direction from the emission source. However, for the Plant Washington modeling, Commenters treated the entire modeling domain as agricultural lands (Land Use Category 2), which best corresponds to the predominant land use in the applicable modeling domain.

Deposition Modeling Results

Commenters ran the AERMOD model separately to calculate the deposition for Hg(II) RGM and Hg(0) Elemental. *See* Ex. 191.[147] Commenters then calculated total mercury deposition as the sum of the individual species. *Id.* The AERMOD model normally returns the deposition result in units of grams per year per square meter. In order to provide for added precision in the modeling result, Commenters input the emissions as nanograms per second, which resulted in the deposition values from AERMOD in nanograms per year per square meter. *Id.*

To assess the total deposition over the Upper Ogeechee River watershed, Commenters averaged the AERMOD results over all receptors (each receptor represents a 4 square km area of the watershed). *Id.* Commenters were then able to calculate the total mercury deposition as the average deposition value multiplied by the total area of the watershed. *Id.*

The AERMOD model result averaged over all receptors computed to 1.356E-02 micrograms of mercury per square meter per year. *Id.* The modeled area of the Upper Ogeechee River watershed is approximately 2,816 square km or 2.816+E09 square meters. Thus, the annual mercury deposition from Plant Washington with the potential to reach already impaired waters of the Upper Ogeechee River is 38.2 grams. *Id.*

The current TMDL for mercury in the Upper Ogeechee River is 1.7 nanograms per liter (parts per trillion). Ex. 188.[148] Using U.S. Geological Survey National Water Information System stream flow data, the minimum annual average stream flow for the Ogeechee River at Midville, GA is approximately 600 cubic feet per second, which

[147] AERMOD Modeling for Upper Ogeechee Hg Deposition.

[148] Ogeechee River TMDL Report; *see Total Maximum Daily Load for Total Mercury in Ogeechee River August 2004*, available at *http://www.epa.gov/region04/mercury/documents/ogeecheeHgTMDL.pdf.*

equates to about 17 cubic meters per second. At this stream flow, the annual water volume in the river would be 5.36E+11 liters.

Based on these parameters, Plant Washington's mercury emissions would increase the average mercury concentration in the Ogeechee River by 0.071 nanograms per liter, representing 4% of the total allowable mercury TMDL for the Upper Ogeechee River watershed. Ex. 191.[149] This is a significant additional contribution of mercury from an individual emission source to a water body that already violates water quality standards for mercury. As part of the TMDL process, EPD must assure reductions of mercury loading to the Upper Ogeechee River watershed. Accordingly, EPD should require that Power4Georgians eliminate all mercury emissions from Plant Washington that have the potential to deposit in the Upper Ogeechee River watershed. Alternatively, EPD must develop a mercury reduction strategy and waste load and load allocations that include modeled mercury deposition from Plant Washington, and demonstrate that these reduction strategies will meet the mercury TMDL for the Upper Ogeechee River. EPD should complete and implement this process prior to issuing a final PSD permit for Plant Washington.

III. EPD's Proposed HAP Limits Fail to Reflect MACT for Plant Washington.

EPD has not proposed legally sufficient limitations for the Plant's emissions of hazardous air pollutants ("HAP"). Section 112 of the Clean Air Act requires every major source of hazardous air pollutants to limit its emissions of such pollutants to a rate consistent with the "maximum achievable control technology" ("MACT"). 42 U.S.C. § 7412 (d)(1).

Congress enacted the present version of Section 112 to address two central concerns. First, the air pollutants addressed by Section 112 are very toxic, "pos[ing] a significant threat to public health." S. Rep. No. 101-228, 1990 U.S.C.C.A.N. 3385, 3517 (1989). When Congress amended the Act to create the currently applicable requirements, studies estimated that the "cancer incidence attributable to toxic air pollution may be as high as 500,000 fatal cases for those Americans now alive." S. Rep. No. 101-225, 1990 U.S.C.C.A.N. 3385, 3514 (1989). Hazardous air pollutants "also cause widespread environmental degradation." Lakes and rivers in more than 45 states and several tribes all across the United States are now posted with fish advisories and warnings for pregnant women and children because of high mercury levels in fish attributable to mercury emissions from coal-fired power plants.

Second, Congress amended section 112 in response to agencies' persistent failure and delay in regulating these air toxics. Congress described efforts to reduce hazardous air pollution as "a record of false starts and failed opportunities" and speculated that agency foot-dragging might be motivated by the fact that reductions might be "potentially very costly for some source categories or pollutants." *Id.* at 3517-18. Those twin legislative concerns – enormously harmful pollutants, and regulatory agencies that had

[149] AERMOD Modeling for Upper Ogeechee Hg Deposition.

persistently failed to address them – resulted in a legal framework that demands strict limitations and provides agencies with little discretion to relax or avoid those limits.

EPA has listed oil- and coal-fired power plants as major sources of HAP, subjecting such plants (including Plant Washington) to Section 112's requirements. Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units, 65 Fed. Reg. 79,825 (December 20, 2000).[150] Coal-fired plants "emit a significant number of the 188 HAP" regulated by Section 112, including mercury, arsenic, chromium, beryllium, lead, manganese, selenium, dioxins, and a variety of acid gases (including hydrogen chloride and hydrogen fluoride). Each of those toxic pollutants poses substantial health concerns. For example, "[o]ffspring born of women exposed to relatively high levels of [mercury] during pregnancy have exhibited a variety of developmental neurological abnormalities, including delayed developmental milestones, cerebral palsy, and reduced neurological test scores." *Id.* at 79,829. There is also new epidemiological evidence that high levels of mercury result in fatal and non-fatal heart attacks among adult males.[151] Arsenic, chromium, dioxin and beryllium are all likely carcinogens, *id.* at 79,827, and acid gases cause respiratory disease and other illnesses.

A. MACT Limits for New Sources of Hazardous Air Pollution.

Section 112 prohibits any person from "construct[ing] or reconstruct[ing] any major source of hazardous air pollutants," or "modify[ing]" such a source, "unless the Administrator (or the State) determines" that the source will meet the applicable MACT limits. 42 U.S.C. § 7412(g)(2). Where, as here, the United States Environmental Protection Agency ("EPA") has failed to promulgate national MACT standards for the new source, EPA or the State must determine the applicable MACT standard for the source on a "case by case basis." *Id.*

The MACT determination must achieve:

> the maximum degree of reduction in emissions of [hazardous air pollutants] which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs

[150] EPA unlawfully "de-listed" power plants from the 112 list in 2005. 70 Fed. Reg. 15,994 (Mar. 29, 2005). The United States Court of Appeals for the D.C. Circuit has vacated that decision; it has no legal effect. *New Jersey v. E.P.A.* 517 F.3d 574 (D.C. Cir. 2008); *Envtl. Defense v. Leavitt*, 329 F. Supp. 2d 55, 64 (D.D.C. 2004) ("When a court vacates an agency's rules, the vacatur restores the status quo before the invalid rule took effect."); *Envtl. Defense v. EPA*, 489 F.3d 1320, 1325 (D.C. Cir. 2007) (while remanded regulations remain in effect, vacated regulations do not); *Campanale & Sons, Inc. v. Evans*, 311 F.3d 109, 127 (1st Cir. 2002) (option of vacating a regulation described as "overturning it in its entirety").

[151] *Economic Valuation of Human Health Benefits of Controlling Mercury Emissions from U.S. Coal-Fired Power Plants*, NESCAUM, February 2005.

> of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

40 C.F.R. § 63.43(d)(2); *see also* 42 U.S.C. § 7412(d)(2). The Act and implementing regulations further sets a "floor," establishing the maximum emissions that may be permitted as MACT:

> The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source . . . .

40 C.F.R. §63.43(d)(1); *see also* 42 U.S.C. § 7412(d)(3). To reach that "maximum degree of reduction," the permitting agency must examine "methods, systems, and techniques" of HAP-reduction, including, but not limited to, measures which:

> (A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials, or other modifications,
> (B) enclose systems or processes to eliminate emissions,
> (C) collect, capture or treat such pollutants when released from a process, stack, storage, or fugitive emissions point,
> (D) are design, equipment, work practice, or operational standards (including requirements for operator training or certification) . . .
> (E) are a combination of the above.

42 U.S.C. § 7412(d)(2); *see also* 40 C.F.R. §63.41 (definition of "control technology").

Furthermore, the permitting authority must set a MACT limit or requirement for each HAP to be emitted by the proposed facility. Section 112(d) requires "the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section." 42 U.S.C. § 7412(d)(2). Section 112 defines "hazardous air pollutants" to include "*any* air pollutant listed pursuant to [Section 112(b)]." *Id.* § 7412(a)(6) (emphasis added); *see also Nat'l Lime Ass'n v. Environmental Protection Agency*, 233 F.3d 625, 633-34 (D.C. Cir. 2000).

B. The Draft Permit Fails to Set Adequate Limits for All Hazardous Air Pollutants Emitted by the Plant.

The draft permit provides direct MACT limits for mercury ("Hg"), hydrogen fluoride ("HF"), and hydrochloric acid ("HCl"). It further includes limits on filterable particulate matter as a "surrogate" for all non-Hg metal HAPs and on carbon

monoxide ("CO") as a surrogate for all organic HAPs.[152] Those surrogates fail to adequately address all of the HAPs that will be emitted by Plant Washington.

As an initial matter, those limits fail completely to address radionuclides and hydrogen cyanide, both of which will be emitted by the Plant. Though EPA has suggested that Section 112 does not apply to radionuclide emissions from power plants, the law demands a MACT limit for every HAP emitted by the Plant. *See* 42 U.S.C. § 7412(A)(6).

Furthermore, surrogate limits may be used in lieu of limits directly addressing each HAP only under limited circumstances. *Nat'l Lime*, 233 F.3d at 637-39; *Sierra Club v. EPA*, 353 F.3d 976, 982-985 (D.C. Cir. 2004) (*Sierra Club I)*. A regulator may not arbitrarily identify a surrogate without specifically linking the surrogate with *each HAP* that it is intended to represent. *See Mossville Envtl. Action Now v. EPA*, 370 F.3d 1232, 1243 (D.C. Cir. 2004).[153] Furthermore:

> [Particulate matter] is a reasonable surrogate for HAPs if (1) "HAP metals are invariably present . . . in [particulate matter];" (2) "[Particulate matter] control technology indiscriminately captures HAP metals along with other particulates;" and (3) "[Particulate matter] control is the only means by which facilities 'achieve' reductions in HAP metal emissions."

Sierra Club I, 353 F.3d at 984 (quoting *National Lime*, 233 F.3d at 639).

Power4Georgians proposed, and EPD accepted, two surrogate scenarios, neither of which actually analyzed or justified the use of surrogates or established any correlation between the HAPs and the surrogates, as required under the MACT analysis. While Plant Washington's MACT Application asserts a relationship, the limited information provided by the company does not support such a relationship. Thus, the surrogate limits in the draft permit fail to meet those standards.

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[152] *See* Georgia EPD's August 2009 Notice of MACT Approval for Plant Washington, Power4Georgians, LLC, Table I (in Appendix A of EPD's Preliminary Determination).

[153] The Court in *Mossville* rejected EPA's reliance on vinyl chloride as a surrogate for all HAP from PVC production facilities, ruling unambiguously that EPA was required to "establish a correlation between the surrogate and the HAP" and that to do so the agency was affirmatively required to identify each HAP that the facility would emit, and directly link each such HAP with the chosen surrogate. 370 F.3d at 1243. It was fatally insufficient for EPA to simply assert without detailed, HAP-specific analysis that vinyl chloride was an appropriate surrogate for all HAP.

1. Filterable Particulate Matter Is Not an Adequate Surrogate for All Non-Hg Metal HAPs.

a. HAP Metals Are Not Invariably Present In Filterable Particulate Matter.

The Notice of MACT Approval relies on filterable particulate matter (PM) as a surrogate for control of non-Hg metal HAPs. The Plant Washington application for MACT Approval identifies ten non-Hg metal HAPs that are expected to be emitted by a coal-fired power plant, including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium. *See* Table 10-13 of the December 2008 Plant Washington Permit Application at 10-50.

As early as 1993, EPA stated that "[i]t has become widely recognized that some trace metals concentrate in certain waste particle streams from a combustor (bottom ash, collector ash, flue gas particulate), while others do not…."[154] These elements are not all consistently present in particulate matter (that is, the particulates that arrive at the inlet to the particulate control device). Ex. 1[155] at 223-224; Ex. 2.[156] Some are present as gases and as such are not removed by pollution-control devices that limit particulate matter. EPA divides the metals into the following groups: "Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment; Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size; Class 3: Elements which are intermediate between Class 1 and 2; Class 4: Volatile elements which are emitted in the gas phase."[157]

These substances are not all consistently present in particulate matter (that is, the particulates that arrive at the inlet to the particulate control device). Ex. 1,[158] and Ex. 2.[159] It is well known and has been widely reported that the metallic HAPs fall into three classes. Class I elements (*e.g.*, beryllium, manganese) do not volatilize during

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[154] *See* Emission Factor Documentation for AP-42, Section 1.1, Bituminous and Subbituminous Coal Combustion, EPA OAQPS, April 1993, at 2-14 (Available at http://www.epa.gov/ttn/chief/ap42/ch01/index.html).

[155] Minghou Xu, Rong Yan, Chunguang Zheng, Yu Qiao, Jun Han, and Changdong Sheng, *Status of Trace Element Emission in a Coal Combustion Process: A Review*, Fuel Processing Technology, v. 85, 2003, at 215-237.

[156] William P. Linak and Jost O.L. Wendt, *Trace Metal Transformation Mechanisms During Coal Combustion*, Fuel Processing Technology, v. 39, 1994, at 173-198.

[157] *Id.* at 2-13.

[158] Minghou Xu, Rong Yan, Chunguang Zheng, Yu Qiao, Jun Han, and Changdong Sheng, *Status of Trace Element Emission in a Coal Combustion Process: A Review*, Fuel Processing Technology, v. 85, 2003, at 215-237 at 223-244.

[159] William P. Linak and Jost O.L. Wendt, *Trace Metal Transformation Mechanisms During Coal Combustion*, Fuel Processing Technology, v. 39, 1994, at 173-198.

combustion and distribute more or less equally between bottom ash and flyash. Class II elements (*e.g.*, lead, cadmium, antimony, nickel) are vaporized in the boiler but are found mainly in the fly ashes after condensation on particles and nucleation mechanisms from decreasing temperature through the control train. Class III elements (*e.g.*, mercury, arsenic, selenium) are vaporized and condense only partially within the control train. *See* reviews in Exs. 1 and 3. In addition, mercury controls, including powdered activated carbon proposed to control mercury emissions from Plant Washington, have been demonstrated to increase the amount of chromium and nickel in stack gases, compared to no mercury control. Ex. 4.[160] Thus, all the metal HAPs that EPD has proposed to be represented by particulate matter are not invariably present in particulate matter.

Some metal HAPs are present as gases, and as such are not removed by pollution control devices that limit particulate matter. Ex. 5.[161] Selenium is the most problematic among the metals; 50% to 100% of the selenium in coal exists as a vapor in exhaust gases. Up to 52% of the arsenic also may be present as a gas. Furthermore, depending upon the fuel and control train, some of the otherwise nonvolatile trace metals, including cadmium, chromium and nickel, may be present in the vapor phase. Exs. 3,[162] 6,[163] 7A,[164] 7B.[165]

Finally, some of the particulate HAPs are present in the condensable fraction of PM10. These include polycyclic organic matter ("POM") and a significant fraction of the metals that exit the baghouse, especially the Class II and III metals. Condensable particulate matter is not included in the surrogate filterable PM proposed to be used for Plant Washington. Condensable particulate matter must be included because the

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[160] *McIlvaine Hot Topic Hour, Hazardous Air Pollutants*, May 15, 2008, Presentation of John Pavlish, EERC. Voice recording also available online to subscribers of McIlvaine Power Plant Knowledge System and available for purchase.

[161] Honghong Yi and others, *Fine Particle and Trace Element Emissions from an Anthracite Coal-Fired Power Plant Equipped with a Baghouse in China,* Fuel, v. 87, 2008, pp. 2050-2057.

[162] Zevenhoven and Kilpinen, *Trace Elements,* Alkali Metals, http://web.abo.fi/~rzevenho/tracalk.PDF.

[163] *McIlvaine Hot Topic Hour, Hazardous Air Pollutants*, May 15, 2008, Presentation of John Pavlish, EERC, Trace Metals in Combustion Systems. Voice recording also available online to subscribers of McIlvaine Power Plant Knowledge System and available for purchase.

[164] Frank B. Meserole and Winston Chow, *Controlling Trace Species in the Utility Industry, In: Winston Chow and Katherine K. Connor* (Ed.), Managing Hazardous Air Pollutants, 1993.

[165] Frank Meserole, Greg Behrens, and Winston Chow, *Fate of Trace Elements in Coal-Fired Power Plants,* 84th Annual Meeting, Air & Waste Management Association, June 1991.

regulated non-mercury metallic HAPs are the metal "compounds", *e.g.*, selenium compounds, arsenic compounds.

Power4Georgians asserts that "[c]ompliance testing conducted at the Wygen II facility in Wyoming in January 2008 clearly demonstrated that those non-mercury metal HAPs evaluated were removed at high efficiencies based on stack testing data (> 90%) through use of a fabric filter baghouse, and therefore existed in the particulate phase as PM." December 2008 Plant Washington Permit Application at 10-40. First, the Wygen II test report did not show that all metal HAPs were removed at greater than 90% removal. For example, the Wygen II report showed only 48.55% removal of cadmium.[166] *See* March 12, 2008 Wygen II Performance Test Report, cover letter at 2. Ex. 125 to this letter. Second, Power4Georgians failed to note that, although the Wygen II permit limits assumed 99.9% control of the metal HAPs (fairly consistent with the expected removal of particulate matter from a baghouse), the Wygen II testing showed less than 99.9% removal of metal HAPs for almost all of the metal HAPs tested. Third, this test report does not definitively demonstrate that the metal HAPs tested all existed in the particulate phase. The Wygen II report notes that the sampling ports at the inlet to the scrubber did not meet EPA's test method 1 specifications. *Id.* at 4. Thus, there is no assurance that the sampling accurately determined inlet concentrations which would in turn mean that removal efficiencies determined might be in error. Also, as we already noted, the removal efficiencies of the metal HAPs were not as high as required by the permit and were not as high as the achievable PM control efficiency with a baghouse (as high as 99.99+%) which means that some of the metal HAPs were either escaping as gases or as fine particulate.

For the reasons discussed above, filterable particulate matter cannot serve as a viable surrogate for all of the non-Hg metal HAP compounds to be emitted by Plant Washington. At a minimum, as with mercury, selenium, arsenic, and chromium should be separately regulated, not lumped into a category that uses particulate matter as a surrogate.

b. The Particulate Control Device Does Not Indiscriminately Capture All HAP Metal Emissions.

As we demonstrate below, the particulate control device -- a fabric filter baghouse, does not indiscriminately capture all HAP metal emissions because these HAPs are concentrated in the smallest particles, which are not efficiently collected by the proposed particulate collection device or because they are present in condensables. Power4Georgians claims the opposite.

[166] Note that the December 2008 Plant Washington Permit Application incorrectly identifies the cadmium removal efficiency as 61.6%, and also identifies incorrect and higher removal efficiencies for other metal HAPs at Wygen II. *See* Table 10-10 of Plant Washington Permit Application, at 10-42. 61.6% removal was the highest cadmium removal efficiency obtained out of three samples, and the lowest cadmium removal was reported to be 39.63%. *See* Wygen II Test Report at 7 (Table 3).

Metallic HAPs that are enriched in particulate matter are, as a general matter, volatilized in the boiler and condense as very fine particulate matter or nanoparticles (typically smaller than 1 micron) in the pollution control train. Exs. 8,[167] 9[168], 10[169]*; see also* Exs. 2 and 6. The highest concentrations of most metallic HAPs are consistently found in the smallest particles. Exs. 1, 11,[170] 12,[171] 13,[172] and 14.[173]

The metallic HAPs of greatest environmental concern are enriched in these tiny submicron particles. Ex. 1, at 222-223. These smaller particles also cause proportionately more of the adverse health impacts because they can penetrate deep into the lungs. Ex. 15. If particulate matter is used as a surrogate for any non-mercury metallic HAP, it should be based on the smallest size fraction feasible. Methods have been developed to measure particulate matter smaller than 2.5 microns or $PM_{2.5}$, which is a better surrogate for metallic HAPs than PM or PM10. However, $PM_{2.5}$ would only be a reasonable surrogate for Class III metallic HAPs.

Second, Power4Georgians claims that PM control technologies will be effective in removing trace metal HAPs. December 2008 Plant Washington Permit Application at 10-40. Power4Georgians cites to the Wygen II test data to support this which, as we discussed above, does not definitively prove this and, in particular, shows that cadmium is not well controlled in particulate control devices. Many other

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[167] 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, Ex. 8; A.S. Damale, D.S. Ensor, and M.B. Ranade, Coal Combustion Aerosol Formation Mechanisms: A Review, Aerosol Science & Technology, v. 1, no. 1, 1982, pp. 119-133; s*ee also,* S.K. Friedlander, *Smoke, Dust, and Haze. Fundamentals of Aerosol Dynamics*, 2nd Ed., Oxford University Press, 2000.

[168] A.S. Damale, D.S. Ensor, and M.B. Ranade, *Coal Combustion Aerosol Formation Mechanisms: A Review*, Aerosol Science & Technology, v. 1, no. 1, 1982, pp. 119-133.

[169] S.K. Friedlander, *Smoke, Dust, and Haze: Fundamentals of Aerosol Dynamics*, 2nd Ed., Oxford University Press, 2000.

[170] Richard L. Davidson and others, *Trace Elements in Fly Ash*, Envtl. Science & Technology, v. 8, no. 13, December 1974, pp. 1107-1113.

[171] 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.

[172] John M. Ondov, Richard C. Ragaini, and Arthur H. Biermann, *Emissions and Particle-size Distributions of Minor and Trace Elements at Two Western Coal-fired Power Plants Equipped with Cold-side Electrostatic Precipitators*, Envtl. Science & Technology, v. 13, 1979, pp. 946-953.

[173] 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.

studies refute this claim. Particulate-matter control devices do not capture these smaller particles as efficiently as they capture larger particles. Ex. 16 (Table 1.1-6)[174], 17 (Fig. 8)[175], 7A[176], 7B[177]. The larger particles contain far less metallic HAPs than smaller particles. As a result, particulate matter controls do not "indiscriminately" capture HAP metals at the same rate as other particulates; they favor the larger, non-metallic HAP-laden particles. For example, one study found that particles smaller than 1 micron made up 5% of the total particle mass before the particulate control device while after the device, they made up 50% of the mass. Ex. 6.

c. Facilities Achieve Reductions in HAP Metal Emissions By Means Other Than Particulate Matter Control.

Particulate matter control is not the only means by which facilities achieve reductions in metallic HAP. As the D.C. Circuit Court of Appeals has observed, in order for particulate matter to serve as an adequate surrogate for metal HAP:

> other inputs [such as fuel type] must "affect HAP metal emissions in the same fashion than they affect the other components of [particulate matter.]" Put another way, "[particulate matter] might not be an appropriate surrogate for HAP metals if switching fuels would decrease HAP metal emissions without causing a corresponding reduction in total [particulate matter] emissions. The reason is clear: if EPA looks only to [particulate matter], but HAPs are reduced by altering inputs in a way that does not reduce [particulate matter], the best achieving sources, and what they can achieve with respect to HAPs, might not be properly identified.

Sierra Club I, 353 F.3d at 985 (quoting *National Lime,* 233 F.3d at 639).

Several "other inputs" affect HAP metal emissions in a different fashion than they affect particulate matter emissions. *Id.* First, "switching fuels would decrease HAP metal emissions without causing a corresponding reduction" in total particulate matter. *Id.*

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[174] U.S. EPA, Compilation of Air Pollutant Emission Factors, September 1998, Section 1.1, Coal Combustion. Ex. 3A.

[175] M.W. McElroy and others, *Size Distribution of Fine Particles from Coal Combustion*, Science, v. 215, no. 4528, January 1, 1982.

[176] Frank B. Meserole and Winston Chow, *Controlling Trace Species in the Utility Industry, In: Managing Hazardous Air Pollutants, State of the Art, Winston Chow and Katherine K. Conner*, 1993.

[177] Frank Meserole, Greg Behrens, and Winston Chow, *Fate of Trace Elements in Coal-Fired Power Plants, Presentation*, 84th Annual Meeting, Air & Waste Management Association, 1991.

Different coals contain different quantities of metallic HAP but the same amount of ash, so that the particulate residue that results from burning different coals can contain more, or less, metallic HAPs. Accordingly, utilizing a cleaner coal (or less coal) can reduce metallic HAP emissions, without reducing particulate emissions.

The effect of fuel-related inputs on metallic HAP emissions differs from such inputs' effect on particulate matter for three reasons. First, the ash[178] content of the coal used as a fuel determines the particulate matter concentration in a plant's flue gases. Ex. 18.[179] A summary of Powder River coal quality (attached as Ex. 19) shows that the ash content remains stable across many coals, while the trace elements can vary significantly. For example, coal from the Jacobs Ranch mine contains about 5.5% ash and lower concentrations of antimony, arsenic, cadmium, chromium, lead and selenium than coal from the Cordero mine. Thus, lower stack emissions of these elements could be obtained by burning Jacobs Ranch coal instead of Cordero coal. Alternatively, Plant Washington could switch from a coal containing low amounts of HAPs, such as Jacobs Ranch, to a similar coal containing higher amounts of HAPs, increasing HAP emissions without affecting particulate matter emissions. Such alterations in fuel supply thus "affect HAP metal emissions" in a far different fashion than they affect particulate matter. *Sierra Club I*, 353 F.3d at 985.

In addition, the relationship between individual HAPs and particulate matter is different for the individual HAPs that are included in the collection of elements represented by the particulate matter surrogate. Exhibits 20A, 20B, and 20C show the relationship between ash content and selenium, lead, manganese, chromium, cadmium, beryllium, and arsenic for Kentucky bituminous coals. These charts show that there is a direct positive relationship between ash and the amount of selenium, manganese, and chromium in this coal, but no relationship between ash and the amount of lead, cadmium, beryllium and arsenic.

Further, the relationship between ash and metallic HAPs varies for different coals in unpredictable ways. The proposed MACT Approval does not totally restrict the specific coal that can be burned at Plant Washington beyond broad generic classifications of "bituminous" and "subbituminous."[180] Exhibit 21[181] reports an

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[178] Ash is a measure of the inorganic material present in coal. This inorganic material is not burned, but becomes bottom ash, removed in the boiler, and fly ash, which becomes airborne and is particulate matter. About 80% of the ash becomes fly ash. *See, e.g.*, Gary L. Borman and Kenneth W. Ragland, Combustion Engineering, WCB McGraw-Hill, 1998, pp. 522-523 and Exhibit 9, Table 1.1-4 (filterable PM emission factors expressed as a constant times the ash content).

[179] J-I. Yoo and others, *Particle-Size Distributions and Heavy Metal Partitioning in Emission Gas from Different Coal-Fired Power Plants*, Envtl. Engineering Science, v. 22, No. 2, 2005.

[180] Although the draft Plant Washington PSD permit states that the permittee shall only fire the broad classification of Powder River Basin (PRB) coal or the more specific classification of Illinois #6 bituminous coal, the permit also allows the burning of coals

analysis of the relationship between ash and metallic HAPs for Pittsburg 8 coals. This analysis found not only different relationships between HAPs and ash for each HAP (*see* equations for each HAP at bottom of page 8), but also different relationships for Kentucky coal in Exhibits 7A and 7B and Pittsburg 8 coal in Exhibit 21. Thus, particulate matter (which arises from coal ash) cannot be reliably used as an indicator of HAP emissions.

Finally, most of the particulate matter mass (98%) is bigger than 1 micron. Ex. 16, Table 1.1-6 of AP-42. Indeed, the sum of the non-mercury metallic HAPs in stack gases reported in lb/MMBtu is less than 1% of the filterable PM reported in the same units. The other 99% of the particulate mass is mostly oxides of silica, iron, sodium, calcium, and potassium. These substances are affected by different chemical and physical mechanisms than the metallic HAPs, which are controlled by volatilization and condensation reactions that concentrate them in the very smallest particles with the larges surface area. Thus, particulate matter per se is too diverse and the target HAP fraction too small to serve as a surrogate for less than 1% of the whole.

As explained above, the prescribed particulate matter limit could be met by removing these larger particles, without removing (or less efficiently removing) the smaller particles where the metallic HAPs are found. The removal efficiency of the two most common particulate matter control devices -- fabric filter baghouses and electrostatic precipitators -- have much higher control efficiencies for big particles than small particles. *See* references cited supra. The most commonly used particulate control devices, including the device proposed here to comply with MACT (a conventional baghouse designed to remove total filterable particulate matter) capture a large fraction of coarse particulates, but are far less effective in capturing finer particulates where the non-mercury metallic HAPs are found, thus providing low total particulate emissions but high metallic HAP emissions. An ESP and a baghouse designed to capture fine particulates might produce similar emissions of total particulates, but very different metallic HAP emissions.

d. BACT Does Not Equal MACT.

The Notice of MACT Determination concludes that MACT will be satisfied by the planned fabric filter baghouse, originally proposed to satisfy BACT for PM10, and by a filterable particulate matter limit of 0.012 lb/MMBtu, 3-hour average, measured by a PM continuous emission monitoring system (CEMS). Notice of MACT Approval (in Appendix A of EPD's Preliminary Determination), at 24. However, different models of the same baghouse vary significantly in their performance. Different types of filtration

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with "equivalent characteristics." *See* Condition 2.11 of the draft Plant Washington PSD permit.

[181] P.R. Tumati and R.A. Bilonick, *Estimating Trace Element Emissions Using USGS Coal Data*, Journal of the Air & Waste Management Association, v. 46, no. 1, 1996, pp. 58-65.

media, cleaning practices, air-to-cloth ratios, and baghouse pressure drop, for example, can significantly affect the performance of baghouses.[182] Ex. 22.[183]

The particulate collection efficiency for conventional baghouses designed to collect PM10 is generally lower for the tiny particles than for larger particles. As a result, they capture "particulate matter," while allowing most of the metallic HAPs (which exist primarily in smaller particles around 0.3 microns) to escape. Exs. 16[184], 15[185] at 1582. A fabric filter system designed to meet BACT for PM, as is the case here, does not meet MACT for metallic HAPs. The maximum achievable control technology must include filtration media, cleaning procedures, and be designed to capture these tiny particles where most of the subject metallic HAPs reside. Furthermore, the MACT floor determination must consider wet electrostatic precipitators, which are designed to specifically remove the smallest particles and are used at a number of coal- and coke-fired electric generating units, including AES Deepwater, Northern States Power/Xcel Energy station, and New Brunswick Power Coleson Cove facility. This technology is permitted for use at other facilities, including Trimble Unit 2 and Dahlman Unit 4.

e. Conclusion

For all of these reasons, EPD's proposed MACT limit for Plant Washington using a filterable PM limit of 0.012 lb/MMBtu as a surrogate for non-Hg metal HAPs thus does not provide a legally sufficient surrogate MACT limit for non-mercury metallic HAP compounds. Any use of particulate matter as a surrogate for non-Hg HAP metals would, first, need to be limited to only those HAP that are consistently present in particulate matter. Second, it would need to be based on the fine fraction of PM (PM less than 2.5 microns in diameter).[186] As set forth above, including larger particulates disrupts the necessary relationship between the surrogate (particulate matter) and the regulated HAP (trace metals). In order to use particulate matter as a surrogate, accordingly, EPD should utilize $PM_{2.5}$ rather than total particulates or PM10. Third, surrogate limits must be continuously monitored to serve as a continuous indicator of HAP emissions. This is consistent with what EPD proposed (i.e., use of CEMS to monitor compliance with the surrogate PM limit for non-Hg metal HAPs) and we think EPD should require such a CEMS to verify compliance with a $PM_{2.5}$ limit for those non-Hg metal HAPs that are

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[182] *See Cement Kiln Recycling Coalition, et al. v. EPA*, 255 F.3d 855, 864-865 (D.C. Circuit 2001).

[183] John D. McKenna, James H. Turner and James P. McKenna, *Fine Particle (2.5 Microns) Emissions: Regulation, Measurement, and Control*, John Wiley & Sons, 2008.

[184] AP-42, Table 1.1-5.

[185] JoAnn S. Lighty, John M. Veranth, and Adel F. Sarofim, *Combustion Aerosols: Factors Governing their Size and Composition and Implications to Human Health*, J. Air & Waste Manage. Assoc., v. 50, 2000, at 1565-1618.

[186] Kilgroe, J.D. et al. *Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report*, EPA-. 600/R-01-109, December 2001. Ex. 23.

consistently present in particulate matter (i.e., at the inlet to the baghouse). The individual HAPs represented by the surrogate must also be separately monitored at least annually to establish a relationship between the surrogate and the HAPs and assure that it is maintained. Fourth, if surrogate MACT limits are used, they should address the three classes of HAPs. Particulate matter would only be a reasonable surrogate for Class I HAPs.

2. Carbon Monoxide is Not an Adequate Surrogate for All Organic HAPs.

a. Organic HAPs Are Not Invariably Present in Carbon Monoxide.

EPD has proposed a limit of 0.010 lb/MMBtu on carbon monoxide ("CO") emissions as a surrogate limit for all organic HAPs to be emitted by Plant Washington. Notice of MACT Approval (in Appendix A of EPD's Preliminary Determination), Table I and at 32. However, carbon monoxide is not an adequate surrogate for all organic HAPs. First, organic HAPs are not "present" in CO at all. Carbon monoxide emissions indicate incomplete combustion and thus provide an indication of whether a facility is fully combusting all of the organic compounds to carbon dioxide and water. Such an "operational standard" may be substituted for limits on actual HAP emissions only where the permitting authority determines that "it is not feasible to prescribe or enforce" HAP limits. 42 U.S.C. § 7411(h). As a result, a CO-based limit – which is, in essence, a surrogate for an operational standard – cannot be used for organic HAPs, where HAP limits are feasible (and EPD has not made any findings that would indicate otherwise).

Second, there are three classes of organic HAPs that behave differently during combustion: (1) volatile organic compounds, which are gases; (2) semi-volatile organic compounds, which may be gases or solids, depending on where in the exhaust gas train they are; and (3) particulate organic compounds, such as polynuclear aromatic compounds and dioxins, which are present in the particulate fraction. See, for example, physical and chemical data for the subject organic HAPs as reported in standard handbooks.[187] A single indicator, CO, cannot be used as a surrogate for these three diverse groups of chemicals because they are chemically and physically dissimilar.

Most of the particulate organic compounds, for example, form primarily downwind from a source in the atmosphere. Thus, filterable particulate matter collected within the stack would grossly underestimate, or not detect at all, these compounds which would most likely be found in the condensable fraction of particulate matter. Ex. 24.[188]

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[187] John A. Dean, Lange's Handbook of Chemistry, 13th Ed., McGraw Hill Book Co., 1985; Robert H. Perry and Don W. Green, Perry's Chemical Engineers' Handbook, 7th Ed., 1997; David R. Lide (Ed.), CRC Handbook of Chemistry and Physics, CRC Press, 75th Ed., 1994.

[188] D.F.S. Natusch, Potentially Carcinogenic Species Emitted to the Atmosphere by Fossil-Fueled Power Plants, Envtl. Health Perspectives, v. 22, 1978, pp. 79-90.

EPD did not include the condensable fraction of particulate matter in its particulate matter surrogate limit for the non-Hg metal HAPs.

Several of these compounds are not products of incomplete combustion, like CO, but rather are formed via distinct chemical reaction pathways. Polynuclear aromatic hydrocarbons are formed in condensation reactions.[189] Dioxins are formed from the reaction of unburned hydrocarbons and chlorine. Dioxins form in the pollution control equipment at flue gas temperatures of 450 to 650 F. Low chlorine fuels, such as coke and subbituminous coals, would form less dioxins than bituminous coals, which contain much higher amounts of chlorine. Ex. 25.[190] As a result, the Plant's dioxin emissions can vary *inversely* to the Plant's CO emissions. Altering the Plant's fuel-mix from all PRB coal, which contains low chlorine to a blend with higher chlorine Illinois #6 coal, for example, would decrease the Plant's CO emissions, but increase dioxins. The permit allows such fuel-blending, and thus such fuel-blending appears to be contemplated within the Plant's routine operations. The proposed MACT CO limit, accordingly, provides no assurance against emissions of the above-described HAP.

b. CO Control Does Not Indiscriminately Capture Organic HAPs, and Facilities Achieve Reductions in Organic HAP Emissions By Means Other Than CO Control.

There are pollution-control methods that would reduce the Plant's organic HAP emissions, without producing a corresponding reduction in the Plant's carbon monoxide emissions. Combustion optimization is the only means by which EPD and Power4Georgians propose to control carbon monoxide (and therefore organic HAPs). This includes changes in combustion residence time, turbulence, and temperature. December 2008 Plant Washington Permit Application, at 10-57, 10-60. Combustion optimization will increase some organic HAPs (such as polynuclear aromatic hydrocarbons), reduce some organic HAPs (such as VOCs), and have no significant effect on certain other organic HAPs (such as dioxin). Other carbon monoxide controls, such as substituting alternative fuels (natural gas, or distillate oil), would reduce organic HAPs at a far higher rate than carbon monoxide.

Beyond that, the draft permit uses as its "surrogate" limit the Plant's 30-day average CO emissions. Measured over such long periods, CO emissions lack the necessarily "indiscriminating" correlation with organic HAP emissions. *Sierra Club I*, 353 F.3d at 984. Those organic HAPs which do result from incomplete combustion can be typically produced in very large quantities during very short "hot spot" incomplete-

[189] William Bartok and Adel F. Sarofim, *Fossil Fuel Combustion: A Source Book*, John Wiley & Sons, 1991; J. Warnatz, U. Maas, and R.W. Dibble, *Combustion: Physical and Chemical Fundamentals, Modeling and Simulation, Experiments, Pollutant Formation*, 2nd Ed., Springer, 1999; *D.J. Hucknall, Chemistry of Hydrocarbon Combustion*, Chapman and Hall, 1985.

[190] Helsinki University of Technology, Halogens, Dioxins/Furans, Slides.

combustion events, such as those that occur during burner malfunction, startups and shutdowns, and shifts in fuel (*e.g.*, from coke to coal or different blends of coke and coal). A 30-day average fails to capture these "hot-spot" events, so that significant variations in HAP emissions may occur without causing a significant change in the 24-hour block average CO emissions. For all of these reasons, carbon monoxide is not an adequate surrogate for the Plant's organic HAP emissions.

c. Conclusion

For the reasons set forth above, CO cannot be used as a surrogate for organic HAP. Carbon monoxide is an acceptable surrogate only for those HAPs (if any) for which actual emission limits are demonstrated not to be technically feasible to monitor. Neither Power4Georgians nor EPD has made such a demonstration. Second, the Plant should be required to perform additional testing to confirm that reduced CO emissions would result in lowered amounts of organic HAP emissions and to identify the organic HAPs that are controlled by combustion optimization. The Plant should be required to test and assess the relationship between CO, combustion temperatures, and HAP emissions, placing special emphasis on evaluating and quantifying the relationship between combustion temperatures and the concentrations of CO and organic HAPs. The Plant's dioxin emissions, in particular, need to be quantified and addressed because of dioxin's high toxicity even at low concentrations. Third, any surrogate MACT limit for organic HAPs must be based on short-time average (of the order of one hour). Organic HAPs are produced at very high "hot spot" rates when combustion is poor. Very large quantities of HAPs can be produced, therefore, during very short periods of incomplete combustion. *See above.* As a result, low long-term average CO emissions may still not protect against very high HAP emissions.

C. EPD's MACT Limits Are Not Based on the Emissions Achieved in Practice by the Best Controlled Similar Source.

MACT determinations generally begin by establishing the "MACT floor" – the "emissions control that is achieved in practice by the best controlled similar source." 42 U.S.C. § 7412(d)(3). EPD's MACT limits for the Plant do not begin at that necessary starting point.

First, EPD has not specifically identified the "best controlled similar source" for any of the HAPs emitted by the Plant. While Power4Georgians did identify a permit limit that it found to be the MACT floor for mercury, the Notice of MACT Approval does not indicate EPD's determination of best controlled similar source. Furthermore, Power4Georgian's analyses of best controlled similar source was a fairly limited review of available information. The law requires EPD "'to make a reasonable estimate of the performance" of the best-controlled unit in the appropriate category. *Cement Kiln Recycling Coalition v. Environmental Protection Agency*, 255 F.3d 855, 861-62 (D.C. Cir. 2001). The draft permit's limits cannot, therefore, plausibly be at least as stringent as the "emissions control that is achieved in practice by the best controlled similar source." 42 U.S.C. § 7412(d)(3).

Once a regulator has identified each HAP that a facility will emit, it must establish MACT *independently for each HAP*. That is, for each HAP, the regulator must identify the individual best performing similar source and identify the emission performance that that source achieves in practice. Accordingly, in this instance, EPD will need to identify the emission limitation achieved in practice by the single best performing similar source for each of dozens of HAP that Plant Washington is likely to emit.

EPD should re-issue the draft permit after conducting a formal MACT analysis based on a survey of the emissions limits achieved by other similar sources. That survey must include, at a minimum: documented inquiries of state and federal regulators who may be making (or have made) MACT determinations for such sources (or who may be imposing other non-MACT limits on HAP); contacts with vendors; inquiries of the Institute of Clean Air Companies and EPA's online clearinghouses on installed technologies and emissions limits achieved in practice, or other groups with information regarding pollution-control technologies; and any other sources of information on HAP emissions. *See* Ex. 26.[191] That information needs to be made available to the public. Absent some knowledge of EPD's analysis, the public cannot reasonably understand the permit, participate in EPD's permitting process, or comment upon the draft permit.

Second, in proposing MACT limits for Plant Washington, EPD set different limits for HCl depending on whether the plant is burning subbituminous coal or a blend of subbituminous and bituminous coal. This approach to setting MACT limits contradicts the requirement that the MACT emission limitation be no less stringent than the emissions control achieved in practice by the best controlled similar source. "Similar source" is defined as:

> [A] stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology.

40 C.F.R. § 63.41. In promulgating that definition, EPA observed that:

> For purposes of section 112(g), two criteria should be used to determine if a source is similar: (1) whether the two sources have similar emission types, and (2) whether the sources can be controlled with the same type of control technology.

61 Fed. Reg. at 68,394. This rulemaking preamble goes on to clarify that classification of "emission types" should be based on the manner in which the source releases HAP – to distinguish, *e.g.*, "vent or stack discharges," from "[e]quipment leaks" or "fugitive emissions," and from "evaporation and breathing losses." *Id.* EPA also stated:

[191] PSD Permit Application for the Council Bluffs Energy Center Unit 4, September 25, 2005.

> The EPA believes that because the Act specifically indicates that existing source MACT should be determined from within the source category and does not make this distinction for new source MACT, that *Congress intends for transfer technologies to be considered when establishing the minimum criteria [i.e., the MACT floor] for new sources.* EPA believes that the use of the word "similar" provides support for this interpretation. The EPA believes that Congress could have explicitly restricted the minimum level of control for new sources, but did not. *The use of the term "best controlled similar source" rather than "best controlled source within the source category" suggests that the intent is to consider transfer technologies [across source categories] when appropriate.*

61 Fed. Reg. 68,384-385 (emphasis added).

Therefore, in setting the MACT floor and assessing potential beyond-the-floor reductions, EPD cannot ignore power plants burning alternative fuels, i.e., it cannot ignore subbituminous-fired sources when setting a limit for a bituminous coal, or vice versa. In other words, the law does not contemplate separate limits for each fuel type.

Furthermore, EPD cannot ignore sources using control technologies that may be transferable to the Plant, i.e., thermal oxidizers or carbon bed absorbers such as ReACT, or alternative combustion methods that may yield lower HAP emissions. The Clean Air Act includes "process changes" and "design" changes among the pollution-reduction methods that must be assessed as part of a MACT determination. 42 U.S.C. § 7412(d)(2). EPD cannot, consequently, define the term "similar source" to exclude such options – especially since the U.S. EPA has concluded that the term "similar source" is meant to broaden, rather than limit, the MACT-floor analysis. *See* 61 Fed. Reg. 63,384-385. For example, circulating fluidized bed ("CFB") units and pulverized coal units have the "same emissions types" and "can be controlled with the same type of control technology." *Id.* They meet the regulatory definition of "similar source." 40 C.F.R. §63.41. Accordingly, the U.S. Environmental Protection Agency has refused to set separate MACT standards for CFBs and pulverized coal units when proposing or promulgating Clean Air Act standards for electric-generating units. *See* 69 Fed. Reg. 4,652, 4,657 (January 30, 2004); 70 Fed. Reg. 28,606, 28,609-10 (May 18, 2005). Thus, for the purposes of Plant Washington's MACT limits, the group of sources that could provide the "best controlled similar source" includes all electric-generating units burning coal of any type – and in some cases, EPD may be required to look beyond coal-burning plants. In the sections of these comments dealing with the HCl and mercury MACT limits, we have provided more detail on this topic.

Third, rather than identify the "emissions control *achieved in practice*," *id.* (emphasis added), by other sources, EPD has essentially selected a purportedly appropriate control *technology*, and made its determination of MACT emission limits based on the expected performance of that technology. The MACT floor is not set by reference to particular technologies; rather, it must be set at the emissions level of the best-controlled similar source. *See Cement Kiln Recycling Coalition,* 255 F.3d at

862-67. Cost plays no role in that determination, nor does the ability of the proposed new source to meet the MACT floor (especially given that modifications to the planned new source can be made to meet the MACT floor, such as switching to a lower mercury content or a lower chlorine content coal). *Id.*

Fourth, both Power4Georgians and EPD have implied that stack test data is not demonstrative of the emissions control of the best controlled similar source. That is wrong. Stack test data is valid data upon which to base a determination of the emissions control achieved by the best controlled similar source. Source-wide MACT standards for other categories of sources have long been based on stack tests. *See, e.g.*, 62 Fed. Reg., 960, 961 (Jan. 7, 1997). Indeed, EPA has formally stated that stack tests suffice to demonstrate continuous compliance with HAP emissions limits. *See, e.g.*, 69 Fed. Reg. 55,217, 55, 224 (Sept. 13, 2004). Further, the Permit itself uses stack tests to determine continuous compliance. Power4Georgians cannot have it both ways. Concerns regarding emissions variability at particular sources for specific pollutants[192] may be addressed by establishing longer averaging times or by applying statistical analyses to reflect variability in emissions.

In addition, EPD cannot ignore emission limits at sources that have not yet commenced operations. The regulatory authorities establishing those limits did so based on specific information which established (to that authority's satisfaction) that such limits could be continuously achieved. At a minimum, EPD is required to assess the information that the regulatory authority relied on in setting more stringent HAP emission limitations for other similar sources, even if that source is not yet operating.

There is a large amount of information that could have and should have been used by EPD to make a MACT determination for Plant Washington. This information includes stack tests conducted specifically to address the Clean Air Act Amendments of 1990 for 130 HAPs at 16 separate coal-fired power plants burning a range of coals and using a range of pollution control trains (*e.g.*, Exs. 27[193], 28[194]), EPA's ICR data on mercury emissions,[195] stack tests conducted to determine compliance with HAP limits in permits, and MACT analyses performed by permitting authorities – from both before EPA delisted electric generating units as well as more recently.

The draft permit's MACT limits are, in defiance of these rules, based on the permit-applicant's preferred control technology to satisfy BACT. EPD thereby

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[192] The variability cited by the permit applicant derives mostly from the use of alternative, cleaner fuels – a pollution-reduction alternative that must be included in the MACT analysis.

[193] Burns and Roe, *Summary of Air Toxics Emissions Testing at Sixteen Utility Power Plants*, Prepared for U.S. Department of Energy, July 1996.

[194] U.S. Department of Energy, *A Comprehensive Assessment of Toxic Emissions from Coal-Fired Power Plants: Phase I Results from the U.S. Department of Energy Study*, Final Report, September 1996.

[195] *See* EPA's Spreadsheet of Data from 1999 ICR Testing of Mercury Emissions, Ex. 29.

ignored a variety of means of reducing the Plant's pollution – most notably, fuel-switching, or use of more efficient process methods rather than adhering to the Act's mandate to base its standards on, *inter alia,* "measures which . . . reduce the volume of, or eliminate emissions of, [hazardous] pollutants through process changes [or] substitution of materials." 42 U.S.C. § 7412(d)(2). *See Cement Kiln,* 255 F.3d at 863. We have provided further details on these deficiencies in the pollutant-specific sections of our comments below.

D. The Proposed Limits For Plant Washington Do Not Represent Maximum Achievable Control Technology.

As a result, in part, of the above-described failings, EPD's proposed MACT limits fail to meet the requirements of law. The following sections explain the inadequacies in EPD's proposed MACT emission limits for Plant Washington, and identify similar sources that are meeting lower emissions levels and/or that have been permitted with lower emission levels than those proposed by EPD as MACT for Plant Washington. MACT may be lower than the emission limits that we identify below because we have not reviewed the entire universe of sources of relevant information in the short time allotted for review of EPD's MACT analysis. EPD is obligated to consider this and all other available information in making its determination of MACT for Plant Washington.

1. Assuming It Is Appropriate to Establish a Particulate Matter Limit As a Surrogate For Non-Mercury Metallic HAPs MACT, EPD's Proposed Filterable Particulate Matter Limit Fails to Reflect MACT.

EPD's proposed MACT limit for non-mercury metal HAPs is a filterable particulate matter emission limit of 0.012 lb/MMBtu, based on a 3-hour average measured by PM CEMs. EPD Notice of MACT Approval, for Plant Washington (in Appendix A of EPD's Preliminary Determination) at 24. As discussed above, this determination is based on the false premise that particulate matter can serve as a surrogate for all non-mercury metallic HAPs. Even if particulate matter were an available surrogate for non-mercury metal HAPs, this proposed emission limit does not satisfy MACT. The proposed filterable particulate matter limit – 0.012 lb/MMBtu (3-hour average) is well above the emission rates being achieved in practice at similar sources. We reviewed a large number of permits and stack tests to determine the lowest filterable PM/PM10 emission rate that has been achieved in practice at a similar source. Tests results are consistently lower than the filterable PM/PM10 limits set in recent permits, as summarized in the table below.

Comparison of Permitted Filterable PM10 Emission Limits With Measured Filterable PM10 Emissions

(lb/MMBtu)Facility	Permit Lb/MMBtu	Test Lb/MMBtu	Ratio (Permit/ Test)	Exhibit Number
JEA Northside[196]	0.011	0.0107-0.002	1.03-5.5	64
Gilbert 3	0.015	0.005	3	65
Hardin	0.015	0.0072	2	66
Springerville 3	0.015	0.0020	8	67A, 67B, 67C
		0.0047	3	68
		0.0013	12	69
Council Bluffs 4 5/07	0.018	0.003	6	70
Council Bluffs 4 8/07		0.008	2	71A, 71B, 71C
Weston 4	0.020	0.0147	1.4	72
Santee Cooper Cross 3	0.015	0.006	2.5	73
		0.0099	1.5	74
Santee Cooper Cross 4	0.015	0.009	1.7	75
Wygen II	0.012	0.00094	13	76

This review indicates that the two CFB boilers located at the JEA Northside facility in Florida, Ex. 32[197], routinely achieve a lower filterable PM/PM10 emission rate than proposed as MACT for Plant Washington. Over fifty stack tests demonstrate a PM10 emission rate of 0.006 lb/MMBtu and a PM emission rate of 0.009 lb/MMBtu, based on a 3-hour average over the period 2003 to 2008. Ex. 31[198] at 63 to 66. These tests include detailed performance tests while burning 100% Pittsburgh 8 coal (0.004 lb/MMBtu), a 50/50 blend of Pittsburgh 8 coal and coke (0.0041 lb/MMBtu), 100% Illinois 6 coal (0.0019 lb/MMBtu), and an 80/20 blend of coke and Pittsburgh 8 coal (0.0024 lb/MMBtu). Ex. 32[199] at 31-38; Ex. 33;[200] Ex. 34.[201]

Similarly low particulate matter emission rates have been achieved at other circulating fluidized bed boilers including Northampton in Pennsylvania (0.0028, 0.0012

[196] The JEA Northside range is for 33 stack tests conducted on CFB A and B between 5/21/02 and 12/12/03.

[197] U.S. Department of Energy, *The JEA Large-Scale CFB Combustion Demonstration Project*, June 2005.
[198] Summary of Florida Stack Tests for Period 2003 - 2008.
[199] Black & Veatch, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.
[200] Black & Veatch, *Fuel Capability Demonstration Test Report 2 for the JEA Large-Scale CFB Combustion Demonstration Project, 50:50 Blend Petroleum Coke and Pittsburgh 8 Coal Fue*l, December 3, 2004.
[201] *Id.*

lb/MMBtu) burning waste coal, Ex. 35[202], 36[203], and Gilbert Unit 3 (0.005 lb/MMBtu) in Kentucky burning bituminous coal at the Spurlock Station. Ex. 37.[204]

The low filterable PM test results are found at facilities burning subbituminous coal as well, including Hardin, Council Bluffs Unit 4, and Wygen II. Thus, based on the data attached and summarized above, the filterable PM MACT floor should be no greater than 0.006 lb/MMBtu, based on a 3-hour average. These limits are consistent with conclusions by others. For example, Matt Haber, EPA Region 9's BACT expert and current Deputy Director of the Air Division of EPA Region 9, concluded that BACT for filterable PM as of 2002 at two existing PC boilers firing PRB coal and equipped with a baghouse was 0.006 lb/MMBtu based on a 3-hour average and monitored via Method 5 and continuously using triboelectric broken bag detectors. Ex. 38.[205]

A detailed beyond-the-floor analysis could well yield a final MACT limit that is lower yet. Other control alternatives, including a wet electrostatic precipitator (WESP) or a more efficient baghouse, could lower particulate matter emissions below the 0.006 lb/MMBtu floor. Because metallic HAPs in the particulate form are typically found in the 1 micron and smaller particles, any particulate matter surrogate should take the form of an emissions limit on the smallest particles that can be measured – particles smaller than 2.5 microns ($PM_{2.5}$). EPD must, therefore, focus its beyond-the-floor analysis on control methods that effectively limit $PM_{2.5}$.[206]

Plant Washington will used a fabric filter baghouse to control PM10. The design basis of this baghouse is unknown and must be disclosed. The filtration media determines the control efficiency of a baghouse for very small particles. There is a wide range of media that can be used, most of which are much more efficient for larger particles than smaller particles. The media Ryton, for example, is commonly used in similar applications for PM control. This media removes 99.9% of larger particles, but operates at far lower efficiencies for the smaller particles where metal HAPs are concentrated. Thus, other media must be considered in a beyond-the-floor analysis. Filtration media are available that allow 99.99% of the $PM_{2.5}$ fraction to be removed. These include Daikin's AMIREX™, PTFE membrane filters,[207] and W.L. Gore's

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[202] Source Test Review, Northampton Generating Co., July 19, 2001.
[203] Bechtel Corp., Report on Emissions Testing, Northampton, PA, November 3, 1995.
[204] Air Quality Testing Services, East Kentucky Power Cooperative, Inc., Spurlock Station, Gilbert Unit 3, Compliance Emissions Test Report, September 2, 2005.
[205] Matt Haber, *Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois, Expert Report*, Prepared for the United States in connection with *U.S. v. Illinois Power Company and Dynegy Midwest Generation, Inc.*, April 2002, p. 3.

[206] EPD's MACT-floor analysis should likewise focus on fine particulates, for the reasons set forth earlier in these comments.
[207] *McIlvaine Hot Topic Hour, Filter Media Selection for Coal-Fired Boilers*, September 13, 2007, Presentation by Todd Brown, Daikin America, Inc. Ex. 39. Voice recording available online to subscribers of McIlvaine Power Plant Knowledge System and available for purchase.

L3650.[208] *See* summary of U.S. EPA's ETV test results in Ex. 41.[209] A bag leak detection system should also be considered as part of the MACT determination.

Other technologies that control $PM_{2.5}$ emission exist and are readily available today. For example, a WESP placed after a fabric filter would eliminate significant amounts of $PM_{2.5}$ emissions. Ex. 42.[210] EPA, and others, has recognized that wet ESPs reduce $PM_{2.5}$ emissions. Exs. 43[211] and 44.[212,213] Indeed, "the WESP is the ultimate device capable of . . . removing ultrafine particles. Many industries are considering the WESP as the maximum achievable control technology (MACT)." Ex. 43 at 6-7. Examples of facilities using wet ESP technology include: (1) Xcel Energy, Sherburne County, Units 1 and 2;[214] (2) First Energy, Mansfield, Unit 2; (3) Duke Power, Cliffside,

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[208] USEPA, *ETV Joint Verification Statement, Baghouse Filtration Products*, W.L. Gore & Associates, L3650, Ex. 40 *(http://epa.gov/etv/pubs/600etv06042s.pdf).* Ex. 40.

[209] Fabric Filtration Media are certified by the U.S. EPA Environmental Technology Verification Program using the "Generic Verification Protocol for Baghouse Filtration Products" to Achieve 99.99% Removal of PM2.5.

[210] Report of Expert Witness Hal Taylor, *Feasibility of Conducting PM2.5 BACT Analysis for the Highwood Generating Station*, September 2007. *See also* Ex. 42 at 9 ("A wet ESP placed after the fabric filter would eliminate up to 99% of the 130 tons of filterable PM2.5 emissions projected in the Highwood facility air permit. In addition, it would eliminate a similar percentage of the 161 tons of condensable PM that this unit will emit"). Notably, the Wet ESP system "has been in successful commercial operation since 1986."

[211] Moretti et al., *Application of Wet Electrostatic Precipitators to Address Fine Particulate Emission Requirements from Fossil-Fueled Combustors*, ICAC 2005.

[212] "*Evaluation of Potential PM2.5 Reductions by Improving Performance of Control Devices: Conclusions and Recommendations*," Prepared for: U.S. Environmental Protection Agency by E.H. Pechan & Associates, Inc., EPA Contract No. 68-D-00-265 at 23 (September 30, 2005) *available at http://www.epa.gov/pm/measures/pm25_recommend_2007.pdf* (describing Wet ESP as an "innovative control system" that "yield[s] higher PM2.5 emissions reductions than the methods identified to improve existing control device performance")

[213] *See also Candidate Stationary and Area Control Measures*, Chicago PM2.5 Workshop, June 21, 2007, Tim Smith, USEPA at slide 15 (recognizing Wet ESP's as "innovative PM2.5 controls)" *available at http://earth1.epa.gov/ttn/naaqs/pm/presents/control_measures_stationary_and_area-tim_smith.ppt. See also*
CIBO Industrial Emissions Control Technology II Conference, August 2 - 4, 2004 Portland, Maine at 6 (explaining that Wet ESP's are an effective control technology for PM2.5: "There are no moving parts in a wet ESP. The [fine] particles never really reach the electrode and are constantly washed away by the water flow)" *available at* http://www.cibo.org/emissions/2004/summary.pdf.

[214] There are 24 WESP modules installed at this plant, 12 each on the two 750-MW units. Ex. 43.

Units 6 and 7; (4) AES, Deepwater (operating since 1986), Ex. 42 at 9, 10; and (5) New Brunswick Power, Coleson Cove, Ex. 43 at 6.[215]

In addition to the wet ESP, other options are available to reduce $PM_{2.5}$ emissions. For example, the EPA's Environmental Test Verification (ETV) program recently verified the performance of the "Advanced Hybrid Particulate Collector" (AHPC) system[216] "as providing the lowest filter outlet concentrations for both $PM_{2.5}$ and total mass concentration."[217] The AHPC system was installed at Otter Tail Power's Big Stone 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% 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.[218]

A 2005 report prepared for the EPA listed numerous innovative control techniques that yield high $PM_{2.5}$ emissions reductions. Included in the list of controls are: (1) Compact Hybrid Particulate Collector, Ex. 44,[219] (2) Indigo Particle Agglomerator,

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[215] In 2002, New Brunswick Power elected to install high-efficiency WESPs following two new limestone-based, wet FGD scrubbers at its 1050-MW Coleson Cove station. Ex. 43 at 6.

[216] 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. "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*

[217] 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

[218] *See 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*, at 12-13.

[219] The Compact Hybrid Particulate Collector (COHPAC) is "a pulse jet filter module operated at a very high filtration velocity (air-to-cloth ratio), installed downstream of an ESP. The function of a COHPAC is as a "polishing filter," collecting the particulate (especially fine particulate) that escapes an ESP. A full-scale COHPAC system has been installed at the Gaston power plant near Birmingham, AL (Southern Company, 2004)." Ex. 44 at 26.

Ex. 44,[220] 45,[221] 46,[222] (3) Wet ESP, Ex. 47,[223] and (4) Wet Membrane ESP, Ex. 44.[224] EPD did not consider any of these technologies for limiting $PM_{2.5}$ emissions from Plant Washington. Indeed, EPD failed to conduct any beyond-the-floor analysis for the non-Hg metal HAPs to be emitted by Plant Washington and thus its MACT analysis for Plant Washington is significantly flawed.

2. Assuming It Is Appropriate to Establish A CO Limit As A Surrogate For Organic HAPs MACT, the CO Limit Fails to Reflect MACT.

EPD established a carbon monoxide emission limit of 0.10 lb/MMBtu, based on a 30-day average as MACT for organic HAPs. *See* EPD Notice of MACT Approval (in Appendix A of EPD's Preliminary Determination), at 1, 32. As discussed above, this determination is based on the false premise that CO can serve as a surrogate for organic HAP. Even if CO were a reasonable surrogate for organic HAPs, the proposed emission limit does not satisfy MACT.

We reviewed a large number of permits and stack tests to determine the lowest carbon monoxide emission rate that has been achieved in practice at a similar source. This review indicates that the circulating fluidized bed (CFB) boilers located at the Cedar Bay facility in Florida routinely achieve a lower carbon monoxide emission rate than proposed as MACT for organic HAPs from Plant Washington. Fifteen stack tests

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[220]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 attaché to each other. These agglomerates enter the precipitator, where they are easily collected due to their larger size." Ex. 44 at 26.

[221] Rodney Truce and others, *Reducing PM2.5 Emissions Using the Indigo Agglomerator*, Mega 2006.

[222] *Indigo Agglomerator: Reducing Particulate Emissions & Reducing, McIlvaine Hot Topic Hour*, November 3, 2006.

[223] *Wheelabrator Air Pollution Control, Inc., PM2.5 Control with Wet Electrostatic Precipitators*, November 2, 2006.

[224] The wet membrane ESP "attempts to avoid problems of water channeling and resulting dry spots than can occur with wet ESPs, and avoiding the higher-cost metals that must be employed to avoid corrosion in a traditional wet ESP. The membranes are made from materials that transport flushing liquid by capillary action effectively removing collected material without spraying (Southern Environmental Corporation, 2004)."

conducted between 2003 and 2008 demonstrate that Cedar Bay achieved a carbon monoxide emission rate of 0.05 lb/MMBtu based on a 3-hour average. These tests are summarized in the following table (*see* Ex. 49 as summarized in Ex. 31):

CEDAR BAY CO TEST RESULTS

Unit	Date	CO lb/MMBtu
CBA	2/28/2006	0.022
CBA	2/22/2005	0.023
CBA	3/4/2003	0.063
CBA	2/20/2007	0.013
CBA	12/7/2007	0.0158
CBB	3/5/2003	0.03
CBB	2/23/2005	0.032
CBB	3/3/2004	0.032
CBB	2/21/2007	0.013
CBB	12/6/2007	0.0215
CBC	3/6/2003	0.051
CBC	2/24/2005	0.027
CBC	2/25/2005	0.027
CBC	3/4/2004	0.024
CBC	2/22/2007	0.014

The data indicates that these are far from anomalous emissions rates. Similarly low CO levels have been achieved at other circulating fluidized bed boilers. *See* Exs. 48, 34, and 33. These include at the JEA Northside circulating fluidized bed boiler, where detailed performance tests were conducted for a range of fuels and at loads of from 40% to 100%. These data are summarized in the following table (*see* Ex. 32):

JEA NORTHSIDE CO TEST RESULTS

Load	Fuel	Date	CO lb/MMBtu
100%	100% Pitts	1/13/2004 1/14/2004	0.026 0.027
100%	50/50 Pitt/Coke	1/27/2004 1/28/2008	0.015 0.016
100%	100% Illn 6	6/8/2004 6/9/2004	0.0198 0.024
100%	80/20 Coke/Pitt	8/10/2004 8/11/2004	0.0127 0.0081
80% 60% 40%	100% Pitts	1/15/2004 1/16/2004 1/16/2004	0.044 0.118 0.053
80% 60% 40%	50/50 Pitt/Coke	1/29/2004	0.024 0.0276 0.08
80% 60% 40%	100% Illn 6	6/9/2004 6/8/2004 6/9/2004	0.031 0.0338 0.138
80% 60%	80/20 Coke/Pitt	8/12/2002 8/13/2004	0.0147 0.0218

Thus, the CO MACT floor limit is no greater than 0.05 lb/MMBtu based on a 3-hour average, the highest reported CO value over the period 2003 to 2008. This is half of the value (0.10 lb/MMBtu) proposed by EPD as a MACT limit for organic HAPS and on a much shorter averaging time than the proposed 30-day averaging time.

EPD must also conduct a beyond-the-floor analysis, assessing, *inter alia*, whether combustion optimization and post-combustion controls, such as regenerative thermal oxidizers or activated carbon processes, such as ReACT (*see* Exs. 51A, 51B and 52), might allow for lower HAP emissions than 0.05 lb/MMBtu, on a 3-hour average. However, neither Power4Georgians nor EPD provided any beyond the floor analysis of MACT for the organic HAPs to be emitted by Plant Washington.

3. MACT For Individual HAPs

EPD established MACT limits for three individual HAPs -- hydrogen chloride, hydrogen fluoride, and mercury. It failed to establish MACT limits for the other 186 HAPs. There is a wealth of information that could have and should have been used to establish MACT for other individual HAPs, as discussed below. As set forth above in section II.A, the law requires a MACT limits for every HAP emitted by the Plant.

Further, EPD's proposed MACT limits for those HAPs that is did propose such limits for are flawed and fail to reflect the maximum achievable control technology at Plant Washington.

a. Hydrogen chloride

The EPD proposed separate MACT limits for hydrogen chloride (HCl): 0.000322 lb/MMBtu for subbituminous coals, 0.00136 lb/MMBtu when burning a 50/50 blend of subbituminous and bituminous coal, and 0.0024 lb/MMBtu for bituminous coals, based on a 3-hour average. These proposed limits do not represent MACT for Plant Washington.

i. The MACT Approval Fails to Identify Important Design Criteria for Plant Washington.

Chlorine originates in the coal. Essentially 100% of the coal chlorine is volatilized in the boiler and is converted to HCl gas. Very little of the chlorine is retained in the ash. Thus, emissions of HCl are determined by the chlorine content of the coal. Coal quality data is required to design a coal-fired boiler, is required to design pollution control equipment, and is required to determine MACT. It is impossible to evaluate whether the proposed MACT limits are reasonable without site-specific coal quality data.

Neither the MACT Application nor the Notice of MACT Approval reports the design basis coal chlorine content (i.e., the specific coal or range of coals that will be used to design Plant Washington's pollution control train), which is essential to determine appropriate HCl MACT limits. Instead, the MACT Application summarizes generic coal quality data for subbituminous and bituminous coal as reported in the U.S. Geological Survey COALQUAL database. December 2008 Plant Washington Permit Application at 10-6, 10-10 to 10-11, Exhibit A. As explained elsewhere in these comments, the very generalized COALQUAL data does not reflect the quality of coal that will be burned by Plant Washington. Source-specific data is required to be part of the MACT application pursuant to 40 C.F.R. § 60.43(e)(2)(viii). There is no way EPD can propose an HCl emissions limit that truly reflects the maximum achievable control technology for Plant Washington without source-specific data.

ii. The MACT Limits Are Less Stringent than Several Other HCl Emission Limits for Coal-Fired Electric Utility Boilers.

EPD established separate MACT limits for hydrogen chloride (HCl) for three separate fuels:

(a) Subbituminous coal:	0.000322 lb/MMBtu, 3-hour average;
(b) Bituminous coal:	0.0024 lb/MMBtu, 3-hour average; and
(c) 50/50 Blend of Coals:	0.00136 lb/MMBtu

2009 EPD Notice of MACT Approval (in Appendix A of EPD's Preliminary Determination) at 26, Draft Permit at Condition 2.13.n. This is not MACT for hydrogen chloride for numerous reasons as follows.

It appears that Power4Georgians and EPD relied on other HCl permit limits to justify the proposed HCl MACT limits for Plant Washington. However, both Power4Georgian's identification of HCl permit limits in its MACT application and EPD's list of permit limits in its Notice of MACT Approval are incomplete. Lower limits have been permitted on similar sources, where similar source includes all coal-fired units (which is consistent with the regulatory definition of "similar source"). Longview in West Virginia was permitted at 0.00001 lb/MMBtu, 3-hour average, Ex. 53. Trimble in Kentucky, which will burn a blend of subbituminous and bituminous coal, has a lower HCl limit than the proposed 0.00289 lb/MMBtu at Plant Washington for a blend of coals, at 0.0005 lb/MMBtu, 3-hr average. Ex. 54. Both of these facilities would use a wet scrubber to control sulfur dioxide (SO2) emissions, which is the most effective control technology for acid gases such as HCl, as Plant Washington will use.

iii. The MACT Limits Are Less Stringent than the HCl Limits Achieved in Practice by the Best Controlled Similar Source.

The proposed HCl MACT limits for Plant Washington are also not reflective of the MACT floor for HCl for coal-fired electric utility steam generating units. The floor should be based on the emissions rate achieved in practice at the best controlled similar source under the worst reasonably foreseeable circumstances. In determining MACT floor for HCl, EPD must not subcategorize sources by coal type or by type of electric generating unit. There is no justification for subcategorizing because the HCl emissions from coal-fired electric utility steam generating units can be controlled with the same types of control technology or methods regardless of type of coal or electric generating unit. *See* definition of "similar source" at 40 C.F.R. § 63.41. *See also* related discussion under Mercury MACT below. Any applicant for MACT Approval has a suite of tools that can be used to match an achieved-in-practice MACT floor and beyond the floor levels achieved at any plant, regardless of type of electric generating unit or coal. EPD made at least three major errors in setting the MACT limit for HCl: (1) failed to select a best controlled similar source that used wet scrubbing; (2) improperly relied only on

permit limits; and (3) ignored stack test data that demonstrate lower limits have been achieved. These are discussed below:

(a) MACT Floor Did Not Consider Best Controlled Similar Source.

SO2, HCl, and HF are acid gases that are removed by similar chemical and physical mechanisms. Both HCl and HF are stronger acids and are thus more reactive than SO2 in scrubber systems. This would typically produce higher removal efficiencies for HCl and HF than for SO2, all other parameters being equal. Emission tests at facilities with wet FGDs found removals of both HF and HCl of over 99%. Exs. 55 and 56.[225] In other words, if a scrubber is designed to remove 95% of the SO2, it would remove more than 95% of the HCl and HF. The best controlled similar source must include wet scrubbing, and acid gas emissions achieved by a wet scrubber represent the MACT floor.

The MACT floor must be based on the emissions control *achieved in practice*. Power4Georgians instead determined that 98.5% HCl control was achievable and then applied that to worst case subbituminous coal characteristics from COALQUAL to determine a subbituminous coal emission limit.[226] It also appears that Power4Georgians relied on the proposed bituminous limit for HCl at Longleaf as defining MACT floor for Plant Washington when it burns bituminous coal. Not only does 98.5% HCl control not reflect the best controlled similar source as discussed above (Exs. 55 and 56), but actual test data show lower HCl emission rates have been achieved in practice. The Plant Washington Permit Application shows this, with Walter Scott, Jr., Unit 4 and Santee Cooper Cross Unit 3 both achieving lower HCl emission rates. *See* December 2008 Plant Washington Permit Application at 10-53. EPD's Notice of MACT Approval also shows that Weston 4 and Hardin achieved lower HCl emission rates than proposed as MACT for Plant Washington. *See* Appendix A to EPD's Preliminary Determination, at 25, 27.

Further, sources burning lower chlorine coals cannot be ignored in determining MACT floor. The 2007 brick kiln case, for example, requires that inputs, *e.g.*, fuels, be considered in setting the MACT floor. *See Sierra Club v. Envtl. Prot. Agency*, 479 F.3d 875, 882-83 (D.C. Cir. 2007). EPD cannot ignore better performing sources with different inputs, *e.g.*, sources burning bituminous coals to set a MACT limit for subbituminous coals. If a source emits a lower HCl emission rate due in part to lower chlorine content of the coal, that source's emissions still must be considered in evaluating

[225] *Clean Air, Report on FGD Feedback Test Program*, Performed for Alstom Power, Inc. at the Unit 4 FGD Absorber Inlet and Stack Duke Energy Marshall Steam Plant, May 29, 2007.

[226] Interestingly, Power4Georgians relied on coal design data in proposing an HCl limit when burning bituminous coal. December 2008 Plant Washington Permit Application at 10-56. As we have discussed elsewhere in these comments, the COALQUAL database should not be relied on to define the characteristics of the coal to be burned at Plant Washington and, instead, project specific design data should be used.

the best controlled similar source. Separate limits based on fuel type, such as what EPD proposed for HCl MACT at Plant Washington, are inconsistent with this framework. The EPA is following the brick kiln case in its currently proposed standard for the Portland cement manufacturing industry. Indeed, EPA rejected subcategorization based on inputs in its proposed standard for Portland cement manufacturers. 74 Fed. Reg. 21,136, 21,145-21,149 (May 6, 2009) (relevant excerpts attached as Ex. 79). This proposed rule for Portland cement manufacturing is EPA's latest statement on the appropriate method of performing a MACT evaluation.

(b) EPD Improperly Relied On Permit Limits in Proposing Bituminous Coal MACT for HCl at Plant Washington.

Regulatory data, such as permit limits, can only be used to establish the MACT floor if these data approximate what is actually achieved in practice. Regulatory data is not a reasonable basis for the MACT floor if these data "are inherently such weak indicators of performance that using them is necessarily an impermissible stretch of the statutory terms." *Sierra Club & NRDC v. USEPA*, 167 F.3d 658 (1999).

Permit limits are typically higher than actual emission rates. The table below identifies other similar facilities that have tested at much lower HCl limits than permitted. Thus, EPD should not only rely on permitted emission limits in determining the level of HCl emissions control achieved by the best controlled similar source.

Comparison of HCl
Permitted Limits and Test Results

Facility	**Permit Lb/MMBtu**	**Test Lb/MMBtu**	**Ratio Permit/Test**	**Ex. Number**
Hardin	0.00118	0.000050	24	66
Weston 4	0.000212	0.000091	2	72
Council Bluff 4 5/07	0.0029	0.000038	73	70
Council Bluff 4 8/07		0.000058	38	71A, 71B, 71C
Gilbert 3 (2005)	0.0035	0.000056	63	65
Gilbert 3 (2006)		0.00071	5	77
Gilbert 3 (2007)		0.00016	22	78
Santee Cooper Cross 3	0.0024	0.000277	9	73

Not only does the above table show that emission rates are typically much lower than permitted emission rates, it provides several examples of lower HCl emission rates that have been achieved in practice at similar sources as compared to the emission limits proposed by EPD as MACT for HCl at Plant Washington.

(c) Ignored Stack Test Data

EPD and Power4Georgians did not consider actual test data for HCl. The only way to determine actual emissions is to measure them. EPD and Power4Georgians failed to collect stack test data available at pollution control agencies across the United States and use this data to establish a MACT floor. We have collected some of this data, which indicates that the proposed HCl MACT limits do not satisfy the MACT floor. EPD should collect additional stack test data and use it to make a MACT floor determination.

Stack tests conducted at units without any HCl limits indicate similarly low emissions to those reported above with limits. Wygen Unit I (2003) fires low sulfur subbituminous coal and is equipped with an SCR, dry FGD, and baghouse. It tested at 1.72×10^{-5} lb/MMBtu on average in 2005. Ex. 58.[227] Neil Simpson II (1995) fires the same low sulfur bituminous coal as Wygen I and is equipped with a dry FGD and baghouse, but has no SCR. It tested at 0.163×10^{-5} on average in 2005. Ex. 59.[228]

The U.S. Department of Energy measured HCl emissions from 16 different coal burning boilers, including those with and without various control options, such as reburn, low NOx burners and selective noncatalytic reduction. This study demonstrated that several of the older facilities emitted lower amounts of hydrogen chloride than EPD's proposed HCl limit for bituminous coal of 0.0024 lb/MMBtu and, in some cases, less than the proposed subbituminous coal limit of 0.000322 lb/MMBtu. These include Boswell (0.0000011 lb/MMBtu), Springerville (less than 0.000176 lb/MMBtu), Yates (0.000742 lb/MMBtu), Bailly (0.00102 lb/MMBtu), Burger using SNCR (0.00077 lb/MMBtu), Arapahoe uncontrolled (0.000630 lb/MMBtu), Arapahoe using SNCR (0.000720 lb/MMBtu), and Shawnee using lime injection with fabric filters (less than 0.000073 lb/MMBtu). Ex. 28, Table 2-6.2, pp. 44-45.

Thus, all of this actual emissions data must be considered in determining the MACT floor for the HCl to be emitted by Plant Washington.

iv. EPD Must Conduct a Revised and Proper MACT Floor Determination.

EPD concluded that MACT for HCl is an emission limit of 0.0024 lb/MMBtu, (bituminous coal) 0.000322 lb/MMBtu (subbituminous coal), and 0.00136 lb/MMBtu when burning a 50/50 blend of coals, based on a 3-hour average. Because it is improper to categorize based on coal type, MACT can be no higher than 0.000322 lb/MMBtu at the maximum. The stack test data that we were able to collect during the public comment period is sufficient to establish that EPD has not selected MACT for HCl. The 17 measurements summarized above average 0.00026 lb/MMBtu, which is a factor of nine lower than EPD's MACT determination for bituminous coal (0.0024 lb/MMBtu) and also lower than EPD's MACT determination for subbituminous coal (0.000322 lb/MMBtu).

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[227] *RMC Environmental, Hydrochloric & Hydrofluoric Acid Testing*, Wygen I Facility, Outlet Stacks, July 2005.

[228] *RMC Environmental, Hydrochloric & Hydrofluoric Acid Testing*, Neil Simpson II Facility Outlet Stacks, July 2005.

These data indicate that EPD should collect additional stack test data from other pollution control agencies and revisit its MACT determination using actual emissions data.

v. EPA Failed to Fully Evaluate Beyond-the-Floor HCl Control Technologies for Plant Washington.

EPD did not adequately consider beyond-the-floor controls for HCl control at Plant Washington. EPD has proposed that hydrogen chloride would be controlled by the wet scrubber, the control designated for SO2 control. The beyond-the-floor analysis only considered the addition of a wet electrostatic precipitator to the BACT pollution control train. Plant Washington Permit Application at 10-55. There is at least one additional technology that should have been considered. In addition, higher HCl control efficiencies with the wet scrubber should have been evaluated.

Wet scrubbers can achieve extremely high levels of HCl control. For example, Alstom submitted data to Duke Energy that indicated 99.7 – 99.9% HCl removal efficiencies have been achieved at two units with a wet scrubber designed to achieve high SO2 removal efficiencies.[229] The Plant Washington Permit Application indicates that the proposed limits for HCl reflect 98.5% control. December 2008 Plant Washington Permit Application, at 10-56. The above-referenced documentation indicate that lower HCl limits could be achieved with a better-designed wet scrubber. Thus, EPD must evaluate higher levels of HCl control that are achievable with a wet scrubber in determining MACT for Plant Washington.

Second, a chloride prescrubber could be used to remove additional HCl. A prescrubber is located ahead of the FGD and uses a spray containing calcium chloride, limestone, or dilute hydrochloric acid to remove chloride. Prescrubbers are in use in the United States at the Philadelphia Electric Eddystone and Cromby plants as well as many others. They are also widely used in Europe.[230] A prescrubber could be used at Plant Washington to reduce HCl emissions below the levels achieved using only a wet scrubber.

In summary, EPD must conduct a thorough evaluation of the MACT floor based on the HCl emission rates achieved in practice at coal-fired electric utility steam generating units and must also evaluate beyond the floor technologies and techniques in

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[229] *See* 10/14/08 Letter from Alstom to Duke Energy, attached as Ex. 55.

[230] Scrubbers Produce Saleable Chemicals, January 29, 2007, *http://www.plantservices.com/industrynews/2007/010.html*; D.T. Llewellyn and R.C. Hudd, Steels. Metallurgy & Applications, 3rd Ed., 1998, p. 367 (Google Books); The McIlvaine Company, Coal-fired Power Plant Becomes A "Green" Chemical Producer, January 11, 2007, *http://www.environmental-expert.com/resultEachPressRelease.aspx?cid=5122&codi=10270&lr=1&word=hydrogen%2Bchloride*; W.S. Kyte et al., *Selective Absorption of Hydrogen Chloride from Flue Gases in the Presence of Sulfur Dioxide*, Environmental Progress, v. 3, issue 3, 2006, pp. 183-187.

proposing an HCl limit that is truly reflective of the maximum degree of HCl emission reduction that is achievable. Furthermore, there is no justification for EPD to subcategorize the determination of MACT floor for HCl based on coal rank and thus EPD must propose one HCl limit for Plant Washington that is no less stringent than the MACT floor and that truly reflects MACT for HCl at Plant Washington.

b. MACT For Hydrogen Fluoride

EPD proposed a single MACT limit for hydrogen fluoride of 2.17×10^{-4} lb/MMBtu based on a 3-hour average. This is not MACT for hydrogen fluoride.

i. The MACT Approval Fails to Identify Important Design Criteria for Plant Washington.

Fluorine, like chlorine, originates in the coal, is volatilized in the boiler, and exits the plant in the gaseous state as hydrogen fluoride (HF). Thus, the amount of fluorine in the coal, coupled with the efficiency of the pollution control train, will determine HF emissions and MACT for HF.

Neither the Plant Washington Permit Application nor the Notice of MACT Approval reports the design basis fluorine content (i.e., the specific coal or range of coals that will be used to design Plant Washington's pollution control train) which is essential to determine an appropriate HF MACT limit. Instead, the MACT Application summarizes generic coal quality data for subbituminous and bituminous coal as reported in the U.S. Geological Survey COALQUAL database. December 2008 Plant Washington Application at 10-56 and Exhibit A. As explained in these comments, COALQUAL data does not reflect the specific quality of coal that will be burned by Plant Washington. Source-specific data is required to be part of the MACT application pursuant to 40 C.F.R. § 60.43(e)(2)(viii). There is no way EPD can propose an HF emissions limit that truly reflects the maximum achievable control technology for Plant Washington without source-specific data.

ii. The MACT Limit Is Less Stringent than Other HF Emission Limits for Coal-Fired Electric Utility Boilers.

EPD proposed a single MACT limit for HF of 0.000217 lb/MMBtu. Lower limits have been proposed and permitted on similar sources, where similar source is all coal-fired boilers, consistent with the regulatory definition as previously discussed. Two units have been permitted with lower HF limits – Longview in West Virginia at 0.00001 lb/MMBtu, 3-hour average, Ex. 53, and Thoroughbred in Kentucky at 0.000159 lb/MMBtu, 30-day average. Ex. 62. Both of these facilities would use a wet scrubber to control SO2 emissions. EPD also proposed a slightly lower HF MACT limit for Longleaf of 0.0002 lb/MMBtu which was based on the use of a dry scrubber that would be less effective at controlling HF than the wet scrubber to be used at Plant

Washington.[231] The fluoride BACT analysis for Plant Washington also identified the Maidsville BACT limit for HF being lower than proposed for Plant Washington, at 0.0001 lb/MMBtu. December 2008 Plant Washington Permit Application at 4-120. Thus, EPD's proposed MACT limit is inconsistent with prior determinations of HF MACT and BACT for similar sources (including its own proposed MACT determination for Longleaf).

iii. The MACT Limit Is Less Stringent than the HF Limits Achieved in Practice by the Best Controlled Similar Source.

The proposed HF limit of 0.000217 lb/MMBtu for Plant Washington fails to be at least as stringent as the emissions control achieved by the best controlled similar source. First, as discussed above, there are three permits for similar sources with lower HF limits: Longview with a HF limit of 0.00001 lb/MMBtu, 3-hour average, Maidsville in West Virginia with an HF limit of 0.0001 lb/MMBtu, and Thoroughbred in Kentucky at 0.000159 lb/MMBtu, 30-day average.

Second, permit limits often overestimate actual emissions. For example, Weston 4 has an HF permit limit of 0.000217 lb/MMBtu. Ex. 63. The initial stack test at Weston 4 reported emissions of 0.000040 lb/MMBtu or five times lower than the limit. Ex. 72. The table below identifies similar facilities that have tested at much lower HF limits than permitted. Thus, EPD should not rely on permitted limits to determine the MACT floor.

Comparison of HF
Permitted Limits and Test Results

Facility	**Permit Lb/MMBtu**	**Test Lb/MMBtu**	**Ratio Permit/Test**	**Ex. Number**
Hardin	0.00051	0.000050	10	66
Weston 4	0.000217	0.000040	5	72
Council Bluff 4 5/07	0.0009	0.000108	8	70
Council Bluff 4 8/07		0.000029	31	71A, 71B, 71C
Springerville 3	0.00044	0.000063	7	67A. 67B, 67C
Gilbert 3	0.00047	0.000056	8	65
Santee Cooper Cross 3	0.00030	0.0000415	7	73

Not only does the above table show that coal-fired power plants emit HF at lower rates then their permit limits, but also this stack test data shows that lower limits than 2.17×10^{-4} lb/MMBtu are being achieved in practice. Stack tests conducted at units without any HF limits indicate similarly low emissions. Wygen Unit I (2003) fires low sulfur subbituminous coal and has an SCR, dry FGD, baghouse. It tested at 0.00000135 (1.35×10^{-6}) lb/MMBtu in 2005. Ex. 58. Neil Simpson II (1995) fires the same low

[231] *See* EPD's June 2009 Notice of MACT Approval for Longleaf (Ex. 126) at 1, 43.

sulfur subbituminous coal as Wygen I and is equipped with a dry FGD and baghouse, but has no SCR. It tested at 0.000000559 (5.59×10^{-7}) lb/MMBtu in 2005. Ex. 59.

In addition, the Gilbert Unit 3 circulating fluidized bed boiler achieved a hydrogen fluoride emission level of less than 0.000056 lb/MMBtu while burning bituminous coal. Ex. 65, p. 3, Table 4. The JEA Northside circulating fluidized bed boiler tested at less than 0.0000309 lb/MMBtu while burning 100% Pittsburgh 8 coal; and at 0.00004582 lb/MMBtu while burning 100% Illinois 6 coal. Ex. 32, pp. 31-38.

The U.S. Department of Energy measured HF emissions from 16 different coal burning boilers, including with and without various control options, such as gas reburn, low NOx burners and selective noncatalytic reduction. This study demonstrated that several of the facilities emitted lower amounts of HF than proposed here as MACT for Plant Washington, including: Springerville (<0.000092 lb/MMBtu), Yates (0.000122 lb/MMBtu), Nelson Dewey (0.000067 lb/MMBtu), Burger using SNCR (0.000039 lb/MMBtu), and Shawnee using lime injection with fabric filters (<0.000023 lb/MMBtu). Ex. 28, Table 2-6.2, pp. 44-45.

Based on the above test data, the lowest HF emission rate being achieved in practice at coal-fired electric utility boilers is at least an order of magnitude lower than the 0.000217 lb/MMBtu HF limit proposed as MACT for Plant Washington. All of this actual emissions data must be considered in determining the MACT floor for the HF to be emitted by Plant Washington.

iv. EPD Must Conduct a Revised MACT Floor Determination.

EPD concluded that MACT for HF is an emission limit of 0.000217 lb/MMBtu based on a 3-hour average. The stack test data that we were able to collect during the public comment period is sufficient to establish that EDP has not selected MACT for HF. The 14 measurements summarized above average 0.000052 lb/MMBtu, which is a factor of more than four lower than EPD's proposed MACT determination. The standard deviation, a measure of variability of this data, is 0.000036 lb/MMBtu. The average plus three standard deviations, which encompasses 99.97% of the measurements, is 0.00016 lb/MMBtu, which is still lower than EPD's proposed MACT level. These data indicate that EPD should collect additional stack test data from other pollution control agencies and make a new determination of HF MACT floor using actual emissions data.

v. EPA Failed to Fully Evaluate Beyond-the-Floor HF Control Technologies for Plant Washington.

EPD did not adequately consider beyond-the-floor controls for HF control at Plant Washington. EPD has proposed that HF would be controlled by the wet scrubber, the control designated for SO2 control. The beyond-the-floor analysis only considered the addition of a wet electrostatic precipitator to the BACT pollution control train. Plant

Washington Permit Application at 10-55. Higher HF control efficiencies with the wet scrubber should have been evaluated.

Wet scrubbers can achieve higher levels of HF control. For example, Alstom submitted data to Duke Energy indicated that 99.7 – 99.9% HF removal efficiencies have been achieved at two units with a wet scrubber designed to achieve high SO2 removal efficiencies.[232] The Plant Washington Permit Application indicates that the proposed limits for HF reflect 98.5% control. December 2008 Plant Washington Permit Application, at 10-56. The above-referenced documentation supports lower HF limits could be achieved with a better-designed wet scrubber. Thus, EPD must evaluate higher levels of HF control that are achievable with a wet scrubber in determining MACT for Plant Washington.

In summary, EPD must properly conduct a thorough evaluation of the MACT floor and of beyond the floor technologies in proposing an HF limit that is truly reflective of MACT for HF at Plant Washington.

c. Mercury MACT

EPD proposed a MACT limit for mercury of 13 x 10^{-6} lb/MW-hr (rolling 12 month average). *See* Condition 2.13.m. of draft Plant Washington permit. Compliance is determined using a mercury continuous emissions monitoring system (CEMS) on a 12-month rolling average basis. EPD Notice of MACT Approval, Appendix A at 42-3. These limits would be met using activated carbon injection. Draft permit at Condition 2.9. This proposed limit fails to reflect MACT for the mercury to be emitted by Plant Washington.

The MACT floor is to be based on the lowest limit that is achieved in practice. Based on a review of EPD's Case-by-Case MACT Determination for Plant Washington (in Appendix A of EPD's Preliminary Determination), it is not entirely clear what criteria EPD applied in determining best controlled similar source for Plant Washington. EPD's MACT determination included mercury emission test result data for EGUs burning both bituminous and subbituminous coal. *See* EPD Preliminary Determination, Appendix A, at 9-10. No indication was given that any of these test results were being discounted due to differences in coal type. The EPD MACT determination also evaluated several circulating fluidized bed ("CFB") boilers with lower limits, but then discounted those emission limits due to differences in fuels. *Id.* at 10. However, EPD's MACT approval did not provide any justification for not considering all solid fossil fuel burning EGUs in determining MACT floor. And yet, the company proposed a mercury emission limit of 15 x 10^{-6} lb/MW-hr (1.68 x 10^{-6} lb/MMBtu) that would only apply when burning subbituminous coal. *Id.* at 13. It appears that the company has proposed no mercury emission limit when burning bituminous coal or when burning a blend of bituminous and subbituminous coal.

[232] *See* 10/14/08 Letter from Alstom to Duke Energy, attached as Exs. 55 and 56.

In its review of beyond-the-floor MACT for mercury, no additional controls or lower mercury emission rates were considered appropriate for mercury by Power4Georgians. *Id.* at 12. Power4Georgians appears to claim that its planned controls of a selective catalytic reduction ("SCR") system, baghouse, and wet scrubber constitute the "best demonstrated technology" for mercury based on EPA's position of its unlawful CAMR regulations. *Id.* Why this is at all relevant to a case-by-case MACT determination is entirely unclear. The CAMR rule was overturned by the U.S. Court of Appeals (*State of New Jersey et al. v. Envtl. Prot. Agency*, 517 F.3d 574 (D.C. Cir. 2008)), and the NSPS standard for best demonstrated technology is not nearly as stringent as the case-by-case MACT standard. 40 C.F.R. §§63.43(d)(1) and (2).

EPD, in its review of the Plant Washington MACT application, added three additional mercury stack test results, two of which were much lower than the 15 x 10^{-6} lb/MW-hr mercury MACT limit proposed by Plant Washington and are even much lower than EPD's proposed 13 x 10^{-6} lb/MW-hr limit. Specifically, according to EPD's Notice of MACT Approval, the Weston 4 unit achieved a mercury emission rate of 1.4 lb/TBtu or 8.79 x 10^{-6} lb/MW-hr and the Newmont Nevada unit achieved less than 7.6 x 10^{-6} lb/MW-hr. *Id.* at 13. And, although it is not appropriate to subcategorize the determination of best controlled similar source based on coal type and neither the company or EPD provided any rationale for any such subcategorization, it is interesting to note that these two units with lower mercury emission rates were burning subbituminous coal and were also equipped with similar controls as Plant Washington will be equipped with.

Although EPD included these additional stack tests in its review of MACT for Plant Washington, it did not rely on those to set a lower limit but instead relied on a proposed MACT limit for the Mid-Michigan Energy LLC facility which proposed, in January 2009, a mercury MACT limit of 13 x 10^{-6} lb/MW-hr. *Id.* at 14. GA EPD determined that this limit reflected a beyond-the-MACT floor level of control for mercury at Plant Washington and so proposed this as its mercury MACT emission limit. *Id*. Under the terms of the draft permit, this limit would apply irrespective of the coal type burned. Draft Plant Washington Permit, Condition 2.13.m.

Both the company's and GA EPD's evaluation of MACT for mercury fail to follow the process required by 40 C.F.R. §63.43(d) in determining MACT for the mercury to be emitted by Plant Washington. As our analysis shows below, there is no justification for subcategorizing the determining of best controlled similar source based on coal type and there are numerous instances of lower mercury emission rates being achieved in practice at similar EGUs.

i. The MACT Approval Fails to Identify Important Design Criteria for Plant Washington..

Neither the company nor EPD have disclosed the design basis of the Plant Washington boiler, including specific information necessary to determine the uncontrolled levels of mercury expected from Plant Washington. While the company

provided coal mercury data for subbituminous and bituminous coals from the USGS CoalQual database, that database is overly broad and does not reflect the specific coals currently proposed to be burned at Plant Washington. Authors of a study that compared USGS data to commercial coal data for the Pittsburgh seam cautioned against use of the USGS data, stating: "use of the USGS data base without careful analysis and treatment of the data will produce misleading estimates for trace element emissions from coal-burning utilities."[233] For example, the coal sampling was irregular, it reflects coal before it is physically cleaned (*e.g.*, ash removal), most of the mines sampled are now closed, etc.[234] Other permits show that lower mercury coal than assumed by Power4Georgians (i.e., 10.2 lb/TBtu[235]) is available from the Powder River Basin.[236]

Such data is required to be part of the MACT application pursuant to 40 C.F.R. § 60.43(e)(2)(viii). There is no way EPD can propose a mercury emissions limit that truly reflects the maximum achievable control technology for Plant Washington without source-specific data. Indeed, EPD's determination can hardly be called a case-by-case analysis without such data. Furthermore, EPD must also obtain specific design thermal efficiency data for Plant Washington's boiler, if EPD is going to set limits in terms of lb/MW-hr that truly reflect MACT for Plant Washington[237]. Therefore, EPD must require Plant Washington to submit detailed data specific to Plant Washington as required to be included in all applications for case-by-case MACT determinations pursuant to 40 C.F.R. § 60.43(e)(2), and it must make a revised determination with all available data made public for review and comment.

ii. The Proposed Mercury Emission Limit Is Not at Least as Stringent as the Emissions Achieved in Practice by the Best Controlled Similar Source.

The first step in determining MACT for Plant Washington's mercury emissions is to determine the level of mercury emissions achieved in practice at the best controlled similar source. For Plant Washington, which is planned to be a supercritical pulverized coal boiler that could burn Powder River Basin subbituminous coal or up to a 50/50 blend

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[233] *See* Tumati, P.R. et al., *Estimating Trace Element Emissions Using USGS Coal Data*, JAWMA, 1996, 46(1), 58-65. Ex. 21 at 1. *See also* Quick, J.C. et al., *Mercury in U.S. Coal: Observations using the COALQUAL and ICR data, Envtl. Geology* (2003) 43: 247-259, Ex. 99

[234] Ex. 21.

[235] *See* Exhibit A of December 2008 Plant Washington Permit Application at A-37.

[236] *See* the air permit analysis for the Hardin Generating Station which indicates the uncontrolled mercury emissions based on coal from the Absaloka mine are expected to be approximately 4.6 lb/TBtu. Ex. 97. *See* also the coal design basis for Weston 4, which shows the uncontrolled mercury emissions from Powder River Basin coal being 6.7 to 7.4 lb/TBtu. Ex. 98.

[237] Further, EPD must ensure that the lb/MW-hr limit reflects the likely thermal efficiency of a new boiler and that it is not based on an outdated or low estimate of thermal efficiency. *See* Exs. 109, 110.

with Illinois #6 bituminous coal, the determination of MACT floor must be based upon the mercury emission rates achieved in practice at all solid fossil fuel fired electric utility steam generating units, irrespective of fuel type or rank of coal.

As discussed above, "similar source" is defined in 40 C.F.R. §63.41 as

> "a stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology."

Electric utility steam generating units burning solid fossil fuel are similar in design and comparable in emissions, regardless of whether such sources burn bituminous coal, subbituminous coal, lignite, coal refuse, or even petroleum coke, and the mercury emissions from such sources could be controlled using the same control technology. While it is true there can be differences in the mercury content of the different fuel types, those differences do not mean that the same mercury emission rates cannot be achieved.

Coal rank affects only the amount of pollutant removal that can be achieved by a given technology design. However, the removal efficiency can be modified by changing the design basis of each control technology. For example, the amount of mercury that can be removed with a sorbent injection system can be increased through sorbent selection and adjusting the amount of injected sorbent concentration. Coal rank will not affect the emission rates achievable, only the design of the control technologies and how they are operated to control emissions. Just as units burning low sulfur coal may be designed with different SO2 controls as compared to those burning high sulfur coal, units burning different types of solid fossil fuels can have mercury controls that are designed specifically to address the characteristics of mercury formation and control from the fuel in question, such as the use of halogenated sorbents for mercury control from low chlorine coals.

Further, sources burning lower mercury controls or higher chlorine coals cannot be ignored in determining MACT floor. The 2007 brick kiln case, for example, requires that inputs, *e.g.*, fuels, be considered in setting the MACT floor. *See Sierra Club v. Envtl. Prot. Agency*, 479 F.3d 875, 882-83 (D.C. Cir. 2007). EPD cannot ignore better performing sources with different inputs, *e.g.*, sources burning bituminous coals to set a MACT limit for subbituminous coals. If a source emits a lower mercury emission rate due in part to lower mercury content of the coal, that source's emissions still must be considered in evaluating the best controlled similar source. Separate limits based on fuel type are inconsistent with this framework. The EPA is following the brick kiln case in its currently proposed standard for the Portland cement manufacturing industry. Indeed, EPA rejected subcategorization based on inputs in its proposed standard for Portland cement manufacturers. 74 Fed. Reg. 21,136, 21,145-21,149 (May 6, 2009) (relevant excerpts attached as Ex. 79). This proposed rule for Portland cement manufacturing is EPA's latest statement on the appropriate method of performing a MACT evaluation.

(a) With Currently Available Control Options and Technology, Coal-Fired Electric Utility Steam Generating Units Can Meet the Same Level of Mercury Emissions Regardless of Coal Rank/Fuel Type.

The same degree of mercury reduction can now be achieved from coals, regardless of rank, using advances in mercury control technology that have occurred since the research studies relied on in the 2005 proposed rulemaking. Exs. 82-85. These advances include additives to increase the chlorine content of the coal, catalysts that oxidize over 90% of the mercury in coals, and a smorgasbord of sorbents to choose from. As of March 2009, 135 mercury control technology systems had been booked by pollution control vendors at a variety of different facilities. Ex. 87.[238] These advances and experiences have allowed for comparable mercury reductions across all boiler and coal types.

For example, subbituminous coals such as those proposed for Plant Washington typically contain low amounts of chlorine. Thus, the majority of the mercury exiting the boiler is present as elemental mercury, which can be difficult to remove in downstream pollution control devices. In the past, the mercury from these coals was believed to be much more difficult to control than mercury from high chlorine coals, which lead to higher proposed MACT and final NSPS limits for sources burning subbituminous coal. However, extensive research has led to the development of new technologies. Thus, this is no longer the case. In fact, research suggests that it is more difficult to remove mercury from high chlorine bituminous coals, due to sulfuric acid mist. Ex. 88A,[239] 88B.[240] Additional controls, *e.g.*, trona injection, not considered by EPD, may be required to meet BACT if Plant Washington fires such coals.

Mercury can now be controlled to the same degree of reduction when firing any coal type due to commercially available products. First, the chlorine content of low chlorine subbituminous coal can be boosted by blending in 15 to 50% bituminous coal or by adding proprietary chemicals. Exs. 89,[241] 90,[242] and 85.[243] Given that Plant

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[238] Institute of Clean Air Companies, Commercial Electric Utility Mercury Control Technology Bookings, March 2009. *http://www.icac.com/files/public/Hg_Commercial_Bookings_033009_Public.pdf*.

[239] Jill Jarvis and Frank Meserole, *SO3 Effect on Mercury Control, Power Engineering*, January 2008.

[240] Tim Campbell, Influence of SO3 on Mercury Removal with Activated Carbon: Full-Scale Results, EUEC 2008.

[241] Institute of Clean Air Companies, Enhancing Mercury Control on Coal-Fired Boilers with SCR, Oxidation Catalyst, and FGD, *http://www.icac.com/files/public/Hg_FactSheet_SCR-FGD_051606.pdf*.

[242] Michael D. Durham and others, *Mercury Control for PRB and PRB/Bituminous Blends*, PowerGen 2005, *http://www.icac.com/files/public/POWER_GEN_2005_Durham.pdf*.

Washington may be blending up to 50% Illinois #6 bituminous coal with subbituminous coal, this may result in high levels of mercury reduction. Second, specially formulated catalysts can be used to enhance mercury oxidation. Exs. 91[244] and 83.[245] Mercury oxidation is important because it enhances the ability of downstream control equipment to remove mercury. Finally, a large number of sorbents are commercially available and can be matched to specific flue gases to remove over 90% of the mercury. Halogenated sorbents such as bromiated carbon have been demonstrated to remove over 90% of the mercury from several facilities burning subbituminous coal. Exs. 82 and 86.

Thus, there is no basis for subcategorizing determination of similar source based on coal type due to differences in performance of control technologies. Any applicant for MACT Approval has a suite of tools that can be used to match an achieved-in-practice MACT floor and beyond the floor levels achieved at any plant, and this includes units burning waste coal and/or pet coke. Consequently, EPD must determine MACT for mercury irrespective of the type of coal burned.

(b) Mercury Emission Rates Lower than EPD's Proposed Mercury MACT Limit for Plant Washington Have Been Achieved in Practice at Similar Sources.

EPD's proposed mercury MACT limit for Plant Washington of 13 x 10^{-6} lb/MW-hr equates to approximately 1.46 lb/TBtu.[246] Lower mercury emission limits have been achieved in practice at numerous units.

Several units in EPA's 1999 Information Collection Request ("ICR") testing had mercury emission rates lower than 1.46 lb/TBtu as shown in the table below, and none of these units had mercury-specific controls.

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[243] Sharon Sjostrom, *Evaluation of Sorbent Injection for Mercury Control*, Topical Report for Sunflower Electric's Holcomb Station, June 28, 2005.

[244] K. Kai and others, SCR *Catalyst with High Mercury Oxidation and Low SO2 to SO3 Conversion*, PowerGen 2007; K. Kai and others, *New SCR Catalyst with Improved Mercury Oxidation Activity for Bituminous Coal-fired Boilers*, International Conference on Air Quality IV, September 2007.

[245] Sharon Sjostrom, *Evaluation of Sorbent Injection for Mercury Control*, Final Report, December 2008

[246] This conversion was based on a gross heat rate of 8,924.7 Btu/kW-hr calculated from the gross generating capacity for the planned Plant Washington unit of 930 MW and the maximum heat input capacity of 8,300 MMBtu/hr. *See* Exhibit A of December 2008 Plant Washington Permit Application.

Unit	1999 ICR Mercury Emission Rate, lb/TBtu[247]
Kline Township Cogen, Unit 1	0.0816
Scrubgrass Generating Company, Unit 1	0.0936
Mecklenburg Cogeneration Facility, Unit 1	0.1062
Dwayne Collier Battle Cogen Facility, Unit 2B	0.1074
Valmont, Unit 5	0.1268
Stockton, Unit 1	0.1316
SEI Birchwood Facility – Unit 1	0.2379
Intermountain Power Plant, Unit 2	0.2466
Logan Generating Plant, Unit 1	0.2801
Salem Harbor, Unit 3	0.3348
Clover Power Station, Unit 2	0.3529
AES Hawaii, Unit A	0.4606
Clay Boswell, Unit 2	0.6633
Craig, Unit 3	0.7248
W.H. Sammis, Unit 1	0.8291
Charles R. Lowman, Unit 2	0.9706
Shawnee Fossil Plant, Unit 3	1.0507
Cholla, Unit 3	1.2066
Presque Isle, Unit 6	1.2217
Presque Isle, Unit 5	1.2622
Widows Creek Fossil Plant, Unit 6	1.3986

Another example of a unit meeting a lower mercury emission rate is Reliant Energy's Seward Station. The units at this facility achieved mercury emission rates ranging from 0.01-0.02 lb/TBtu which, according to the test report, reflects 100% mercury removal. Ex. 127.[248] Seward Station, a 521 megawatt power plant, consists of two identical CFB boilers burning bituminous waste coal, each equipped with a selective non-catalytic reduction ("SNCR") system, baghouse, in-furnace limestone injection, and flash dryer absorber.[249] These units were burning waste bituminous coal with a mercury content ranging from 0.276 - 0.465 parts per million ("ppm"), presumably this is by weight of mercury in the coal,[250] which is relatively high compared to the mercury coal contents identified in the 1999 ICR test results in Ex. 29.[251]

[247] A copy of the spreadsheet of mercury emission rates measured at these and other electrical generating units as part of the 1999 ICR is available for download at *http://www.epa.gov/ttnatw01/combust/utiltox/utoxpg.html* and is attached as Exhibit 29.
[248] January 12, 2007 Source Test Results for Reliant Energy Seward Station, Boiler Nos. 1 and 2, at 1.
[249] *Id.* at 11.
[250] *Id.* at 15.
[251] Excel Spreadsheet of mercury emissions data collected pursuant to EPA's 1999 ICR, at Column G (avg Hg in fuel, ppmw).

Another example is the MidAmerican Walter Scott, Jr. unit. The MidAmerican Walter Scott Jr. unit attained a mercury emissions rate lower than 0.72×10^{-6} lb/MMBtu during the May 2007 test. *See* Ex. 70.[252] The Plant Washington permit application identifies a different test result for the Walter Scott Jr. Unit 4 and also neglects to mention that the results fell below the PQL so the PQL (which, in the case of this other stack test, was 1.2 lb/TBtu). *See* Exs. 70 and 71A, B, and C.[253]

Further, the Santee Cooper Santee Cooper Cross Unit 3 was shown in testing to emit mercury at a rate of 0.72 lb/TBtu and 0.58 lb/TBtu. Exs. 73 and 74.

Units that burn pet coke or a blend of pet coke and coal have also been shown to achieve lower mercury emission rates than EPD's proposed MACT limit for Plant Washington which equates to 1.46 lb/TBtu. JEA Northside includes two CFB boilers equipped with spray dryer absorbers and baghouses that burn pet coke and/or coal. These units achieved a mercury emission rate of 0.51 lb/TBtu while burning 70% pet coke and 30% Pittsburgh No. 8 coal, 0.28 lb/TBtu while burning 100% pet coke, and 0.074 lb/TBtu while burning 80% pet coke and 20% Pittsburgh No. 8 coal. Exs. 32, 33, and 34.

Yet, another example is the Hardin Generating Station. This facility burns Powder River Basin subbituminous coal, and is equipped with an SCR, dry scrubber, fabric filter, and ACI system. This facility is equipped with Hg CEMs and, while we have not yet obtained the specific mercury CEMs data, a presentation on the mercury reductions achieved at Hardin provides a graphical representation of 10 months worth of mercury emissions. *See* Ex. 93.[254] Specifically, the 17th slide of the attached presentation shows that, over the 10 month period from September 2007 to July 2008, mercury emissions from Hardin rarely ever exceed 0.5 $\mu g/m^3$ and are often much lower than 0.5 $\mu g/m^3$.[255] Assuming this mercury emissions data reflects standard temperature and pressure, a mercury concentration in the stack of 0.5 $\mu g/m^3$ reflects an emission rate of 0.305×10^{-6} lb/MBtu (or 0.305 lb/TBtu).[256] This is much lower than the mercury emissions rate EPD has proposed for Plant Washington, thus providing convincing long-

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[252] *See* May 2007 test report for Council Bluffs Energy Center Unit 4. Note that the report indicates results were below the Practical Quantification Level (PQL) so the PQL was listed.

[253] August 2007 test report for Council Bluffs Energy Center Unit 4.

[254] Results of a Long Term Mercury Control Project for a PRB Unit with an SCR, Spray Dryer and Fabric Filter, presented at 11th Annual EUEC Conference, January 30, 2008.

[255] *Id.* *See* top graph on 17th slide, HgT out (magenta line) and Hg0out (blue line). Note that, for the most part, the Hg0 and HgT are identical and are represented in the graph with one line for Hg0 out (typically less than 0.5 $\mu g/m^3$). HgT = total mercury and HgO = oxidized mercury.

[256] Converting ug/m^3 of mercury in the exhaust gas to lb/MMBtu = $[(0.5\ ug/m^3)(9780\ dscf/MMBtu)]/[(10^6)(453.6\ g/lb)(35.31\ dscf/dscm)] = 0.305 \times 10^{-6}$ lb/MMBtu. = 0.305 lb/TBtu.

term (10 months) data measured by a Hg CEMS that lower mercury emission rates have been achieved in practice.

It also must be stated that the mercury test results for these units do not necessarily reflect the lowest mercury emission rates that can be achieved at subbituminous coal-fired power plants. They simply reflect the mercury emissions rates achieved at these units based on their design and the emission limit they are trying to achieve. The level of mercury control achieved with ACI can be improved with increased amounts of carbon injected, as well as with different sorbents such as bromiated carbons as discussed above. Furthermore, other options are available to improve mercury control such as blending with higher chlorine bituminous coal.

For example, at the time of the mercury stack testing at MidAmerican's Walter Scott Jr. unit, the unit was subject to a mercury emission limit of 1.7×10^{-6} lb/MMBtu. Ex. 94.[257] Because it costs more to inject more carbon or to use halogenated carbons, it is not reasonable to expect the emissions testing at this unit to reflect the lowest mercury emission rate achievable at this unit because the operation of the ACI system is tied to ensuring compliance with the applicable emission limit and not necessarily to achieving the lowest Hg reductions.

In addition, use of a fabric filter followed by a wet scrubber (i.e., Plant Washington's proposed configuration) as compared to a dry scrubber followed by a fabric filter (the Walter Scott Jr. Unit 4 configuration) would improve mercury control. Studies have demonstrated that elemental mercury, the major form of mercury from subbituminous coals, is more soluble in the wet scrubber scrubbing solution. [258] The wet scrubber also removes 50% or more of the particulate matter, including absorbed mercury, while the dry scrubber is far less efficient at removing particulate matter. In addition, because the dry scrubber is typically situated before the baghouse and because it removes chlorine as discussed elsewhere in these comments, less chlorine is available in the downstream activated carbon injection system and baghouse where it would otherwise facilitate mercury removal. In contrast, the baghouse and ACI system in a control train with a wet scrubber are located upstream of the scrubber and thus more chlorine would be available to oxidize the mercury so that it is more readily captured in the baghouse.

All of these test results provide irrefutable evidence that lower mercury emission rates than EPD's proposed 13×10^{-6} lb/MW-hr mercury MACT limit (or approximately 1.46 lb/TBtu) have been achieved in practice, including as measured by CEMs and on a

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[257] MidAmerican Walter Scott, Jr., Air Permit. *See also* Iowa DENR Technical Support Document for PSD Permits for Project Number 02-528, Plant Number 78- 01-026 at 43, 45, Ex. 95.

[258] U.S. EPA, *Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report Including Errata Dated 3-21-02*, Report EPA-600/R-01-109, Table ES-1. Ex. 23.

long term basis. Consequently, GA EPD's proposed mercury MACT standard for Plant Washington utterly fails to reflect the MACT floor.

(c) EPD and Plant Washington Cannot Ignore These Lower Mercury Emission Rates Achieved Due to Claims of Short Duration Testing.

A stack test report shows what has been "achieved" and what is "achievable." That alone should end any dispute as to whether such data is relevant to the MACT analysis. While stack tests are just a snapshot of operations under carefully observed and controlled conditions, these tests have historically been all that is required to demonstrate compliance with permit limits, including MACT limits. If periodic tests with no intervening compliance demonstrations are adequate to demonstrate compliance with MACT limits, they should also be adequate to establish the emission levels that must be complied with in the first place.

Long term test data is not required to set the MACT floor. There is very little long-term test data for any of the subject HAPs or their surrogates. If long-term emissions data were a prerequisite, it would be impossible to make a MACT determination. The EPA has routinely used other approaches to determine the best controlled similar source. These other approaches include relying on short-term test data and applying a technology based approach when there is a lack of data. These and others have been upheld by the D.C. Circuit, so long as they are reasonable.[259] These decisions indicate that measured, long-term emissions data is not required to establish the floor or beyond the floor MACT emissions rate.

In setting an emission rate reflective of the MACT floor, EPD can account for variability in the effectiveness of control measures and techniques by setting the MACT floor based on the emissions control achieved by the best controlled similar source under the "worst reasonably foreseeable circumstances." In a November 2003 memo to the Utility MACT Project File, EPA explained how you could account for such variability. Specifically, EPA stated "there are two fundamentally different approaches to incorporating variability into the proposed [MACT] rule: (1) including variability in the MACT floor calculation; *or* (2) including variability in the compliance method."[260] EPA further stated:

> Addressing variability in the compliance method would involve allowing an averaging time for compliance that would accommodate variations in pollutant emissions over time. For example, averaging over a month or

[259] See, e.g., *Cement Kiln Recycling Coalition v. EPA*, 255 F.3d 859, 862, 865 (D.C. Cir. 2001); *Mossville Envtl. Action Now v. EPA* 361 F.3d 976, 1241 (D.C. Cir. 2004); *Sierra Club v. EPA* 353 F.3d 982-983 (D.C. Cir. 2004); *Nat'l Lime Association v. EPA,* 233 F.3d 630-633, 637-640 (D.C. Cir. 2000).

[260] 11/26/03 Memorandum from William Maxwell to Utility MACT Project Files at 2 (Ex. 106).

> year of data will provide opportunity for variations in the amount of a constituent in the fuel to be accommodated without exceeding the emission limitation.[261]

Use of a long-term average smoothes out the ups and downs or variability in measured data. This is shown in Figure 7.1 from Exhibit 107, which graphically displays the same data set on an instantaneous basis (as measured by a CEMS), on a one-hour basis, and on a four-hour basis. This chart shows that the longer 4-hour averaging time smoothes out the peaks and valleys in the instantaneous values, resulting in a straight line as a function of time. The shorter term data is very ragged with lots of peaks and valleys. Further, a 3-hour stack test conducted once a year has an equal chance of coming in either higher or lower than the standard.

Indeed, long term testing of mercury emissions at coal-fired electric utility steam generating units with mercury controls have shown very little variability in mercury emissions, and a long term averaging time could readily address the few excursions in mercury emissions. For example, see the 17th slide of the attached presentation on mercury emissions at the recently constructed Hardin Station which is equipped with a dry scrubber, baghouse and ACI system and burns subbituminous coal.[262] Once carbon injection started, its Hg CEMs showed only a few elevated mercury concentrations over a 10 month period.[263] Long term mercury testing has also been conducted for the Toxecon installation for mercury control at Units 7-9 of the Presque Isle power plant in Michigan. While we currently do not have the raw CEMS-measured Hg emissions data for these units, we have summaries from various presentations and reports on the long term operation of the Toxecon mercury controls shows the units consistently achieve over 90% mercury control based on monthly averages.[264]

For all of the above reasons, there is absolutely no valid justification for EPD to ignore short term stack test data in setting the MACT floor for mercury for Plant Washington. Stack tests show what has been achieved and, as such, must be considered in determining the MACT floor for mercury at Plant Washington.

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[261] *Id.*

[262] *See Results of a Long Term Mercury Control Project for a PRB Unit with an SCR, Spray Dryer and Fabric Filter*, 11th Annual EUEC Conference, January 30, 2008, Ex. 93.

[263] *Id. See* top graph on 17th slide, HgT out (magenta line) and Hg0out (blue line). Note that, for the most part, the Hg0 and HgT are identical and are represented in the graph with one line for Hg0 out (typically less than 0.5 $\mu g/m^3$).

[264] *See Toxecon Retrofit for Mercury and Multi-Pollutant Control on 3 90-MW Coal Fired Boilers*, April 2009, Ex. 108; s*ee also* Exs. 100-104.

iii. Relevant Mercury Limits Were Not Adequately Considered by EPD.

There is additional information which indicates that MACT for mercury emissions from Plant Washington is an emission limit lower than 13 x 10^{-6} lb/MW-hr.

Permits

At least 2 permits have been issued with lower mercury MACT limits. Other permits represent other agencies' determination of what has been achieved and is achievable, which is relevant to the subject inquiry. In addition, a beyond-the-floor analysis must also be done at Plant Washington, which sets MACT at the level that is "achievable." An achievable standard clearly contemplates permits as one of the sources that must be considered.

Utah issued a permit in October 2004 for the NEVCO Energy-Sevier project, a 270-MW circulating fluidized bed boiler that will burn a bituminous coal. This permit contains a mercury MACT limit of 0.4 lb/TBtu. Ex. 111. Assuming 38.4% thermal efficiency of the Sevier project boiler, this would equate to 3.6 x 10^{-6} lb/MW-hr. This is lower than the mercury limits proposed for Plant Washington by EPD.

Virginia issued a permit in July 2008 to Virginia Electric and Power Company for two circulating fluidized bed boilers (Dominion Wise County) with a combined output of 668 MW. These boilers would burn bituminous coal and waste coal. The permit contains a mercury MACT limit of 0.88 x 10^{-6} lb/MW-hr (claimed to be equivalent to 0.09 lb/TBtu). Ex. 112. This is substantially lower than the limits proposed for Plant Washington. The fact that these sources will be CFB units does not negate the need for EPD to consider these much lower mercury limits in setting MACT limits for Plant Washington, especially given that even EPA did not subcategorize CFB boilers when it proposed MACT standards in January 2004. Power4Georgians tried to discount this mercury limit because Dominion will be allowed to burn coal refuse. *See* December 2008 Plant Washington Permit Application at 10-26. However, Power4Georgians failed to mention that the Dominion Wise County facility is also authorized to burn bituminous coal (*See* Ex. 112, Condition 8) and will have to meet the same mercury MACT limit regardless of the type of coal it burns.

State Regulatory Programs

Additionally, as a part of establishing its MACT floor, EPD should have contacted Brayton Point power station in Massachusetts and Massachusetts Department of Environmental Protection. The legally enforceable limit for all coal-fired units in Massachusetts is 0.0075 lb/GWh in year 2008, and 0.0025 lb/GWh (or, 0.28 lb/TBtu) in 2012. Similar mercury limits are included in New Jersey State regulations.

iv. The Beyond-the-Floor MACT Analysis Was Inadequate.

The second principle of MACT determinations must be addressed after determining the level of emissions control achieved in practice by the best controlled similar source (i.e., the MACT floor). Specifically, 40 C.F.R. § 63.43(d)(2) states:

> The MACT emission limitation and control technology shall achieve the *maximum emissions reduction* that can be identified from the available information, with consideration of the costs of achieving such emissions reduction and any non-air quality environmental impacts and energy impacts.

40 C.F.R. § 63.43(d)(2) (emphasis added).

The second principle of MACT determinations, often referred to as the "beyond the floor" analysis, essentially calls for an evaluation of all available control technologies, similar to the process required in determining BACT. Indeed, a comparison of the definition of MACT to the definition of BACT used in the PSD program shows that the two definitions are almost identical, except that the floor for determining BACT is the applicable NSPS whereas the floor for determining MACT is the emissions control that is achieved in practice by the best controlled similar source. Consequently, to determine MACT for Plant Washington, an approach similar to the top-down approach of the PSD program should be used for determining beyond the floor MACT for the mercury to be emitted by Plant Washington.

Such an approach would ensure that the potential control technologies that would achieve the maximum emissions reduction are fairly evaluated. One of the most important steps in the top-down BACT process that should apply to a case-by-case MACT determination is the identification of all available control options that have a practical potential for application to the emissions unit and the pollutant.

In determining the control technology representative of MACT, the permitting authority must consider alternative processes and techniques that reduce or eliminate the emissions of HAPs in addition to technologies that collect or treat HAPs. *See* definition of "control technology" at 40 C.F.R. §63.41. Such alternative processes or techniques would include the evaluation of an integrated gasification combined cycle ("IGCC") plant as an alternative process for producing electricity. Studies have shown that it is very economical to control mercury emissions by 90% or more with available carbon bed technology as discussed further below.

In its MACT Application, Plant Washington indicates that no beyond-the-floor limits are warranted. December 2008 Plant Washington Permit Application at 10-39. Although the Plant Washington application goes through many of the DOE/NETL

mercury studies and showed that some of those studies achieved higher levels of mercury reduction than that deemed necessary to achieve the company's proposed mercury MACT limit of 15 x 10^{-6} lb/MW-hr, the permit application did not explain why beyond the floor technologies were not warranted for Plant Washington.

According to the company's calculations, it would have to achieve 84% mercury control to attain its proposed mercury MACT limit of 15 x 10^{-6} lb/MW-hr or 1.68 lb/TBtu. December 2008 Plant Washington Permit Application at 10-39 (Table 10-9). To meet EPD's proposed MACT limit of 13 x 10^{-6} lb/MW-hr (or 1.46 lb/TBtu) then, Plant Washington would need to achieve 86% mercury removal. Yet, mercury removal efficiencies above 90% have been shown to be achievable at coal-fired EGUs with activated carbon or other sorbent injection.

EPD did not do much more for its beyond the floor analysis, except that it found a MACT permit application for a source that would burn subbituminous coal and that proposed a Hg MACT limit of 13 x 10^{-6} lb/MW-hr. Notice of MACT Approval (Appendix A of EPD's Technical Review) at 14. Based on that proposal, EPD reduced the mercury limit for Plant Washington from the 15 x 10^{-6} lb/MW-hr limit proposed by company down to 13 x 10^{-6} lb/MW-hr. *Id.* While that permit application is relevant information for EPD to consider, EPD's beyond the floor analysis should not have stopped there. EPD should have done a much more thorough review in this step of the review to determine an emission limit for Plant Washington reflective of the maximum degree of reduction in mercury emissions that is achievable at the facility.

For example, to conduct a proper MACT analysis, EPD must obtain site-specific information from Plant Washington. At a minimum, the following information must be supplied to support a beyond-the-floor MACT analysis:

- design basis mercury content of each fuel that is proposed to be used;
- uncontrolled mercury emission rate for each fuel that will be used;
- design basis of the activated carbon system, including inlet mercury concentration, control efficiency and carbon injection rate;
- design basis of the wet scrubber and baghouse.

Plant Washington failed to provide any of this data. Further, to set limits in terms of lb/MW-hr, Power4Georgians must also submit site-specific thermal efficiency design data for Plant Washington.

EPD is also required to evaluate all "available information" in determining MACT for Plant Washington. 40 C.F.R. § 63.43(d)(2). Available information includes information provided by others, and thus we have attached documentation for EPD's consideration in determining MACT for mercury at Plant Washington (including documents and studies cited above).

The mercury control efficiency represented by EPD's proposed mercury MACT standards is unknown because Plant Washington has failed to submit uncontrolled

mercury emission rates for the fuels that will be used at Plant Washington as previously stated. In any case, in our opinion, 99% mercury control has been achieved and is achievable for the subject units using bromiated activated carbon, the ReACT technology, or other technologies that are currently available. *See, e.g.*, Exs. 51A,B and 52; *see also* Ex. 118.

For example, packed beds of sorbent material, typically carbon, have been used in Japan and Germany to remove mercury, dioxins, and other HAPs from a wide range of combustion sources, including coal-fired power plants. One such technology is the J-Power Regenerative Activated Coke Technology or ReACT process. This is a multi-pollutant control technology intended for installation downstream of a particulate control device. It removes SO_2, NO_X, mercury, dioxins, other HAPs, and particulate matter. It uses a moving bed of activated coke pellets that is continuously removed and thermally regenerated, producing a concentrated SO_2 stream for sulfur recovery, either as sulfuric acid or gypsum. The process was demonstrated in 2007 on a 2.5 MW slip stream at the 250-MW Valmy Generating Station in Nevada on both sub-bituminous and bituminous coals. The Valmy demonstration reported SO_2 removal of 98->99%, NO_X removal of 26-48%, and mercury removals of 97->99%. Ex. 51A, B.[265]

ReACT has been installed on 14 commercial units to date, including 4 coal-fired utility boilers in Japan and Europe. The technology has been in operation at the 350 MW Takehara Unit 2 since 1995 and the 600 MW Isogo Unit 1 since 2002. A 600 MW unit is currently under construction at Isogo Unit 2. Isogo Unit 1 has achieved greater than 98% SO_2 removal, 10-50% NO_X removal, greater than 95% particulate removal, and greater than 90% mercury removal. Ex. 75, Table 7. "Commercial installations located in Japan and Germany operate at 90-99% SO_2 removal, with SO_2 inlet concentrations as high as 1300 ppm SO_2." Ex. 75, at 14.

In addition, higher mercury control is achievable using a mercury oxidation catalyst, coal blending, high-chlorine fire retardants, or mixing a chlorine-rich additive into the boiler, such as PVC, a high heat content (19,000 Btu/lb), high chlorine, low cost additive.[266] Further, the SWEPCO Turk MACT analysis indicated it would achieve greater than 90% mercury reduction more reliably than other similar units currently in operation due to the method it will use to deliver the activated carbon into the gas stream.[267]

Consistent mercury control requires reliable delivery of the correct amount of activated carbon. Thus, the injection system is a key part of the system design. Most ACI systems use eductors to deliver the activated carbon into the gas stream. These systems operate well in the short-term, but there are long-term reliability issues. An

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[265] C. Dene, J. Gilbert, K. Jackson, and S. Miyagawa, *ReACT Process Demonstration at Valmy Generating Station*, Mega 2008.

[266] *See, e.g.*, Burn Waste PVC in Coal-Fired Boilers and Solve Multiple Environmental Problems, *http://www.mcilvainecompany.com/brochures/newsreleases/NR1242.htm*

[267] *Second Supplemental Response to Comments*, August 1, 2008, AR 3569 at 3575-3576.

eductor is a large nozzle that creates a vacuum that pulls the activated carbon into an air stream that transports it into the flue gas. Eductors operate within very narrow pressure ranges and can be difficult to control. The injection nozzles can plug. The SWEPCO Turk ACI system will use a pressurized tank transfer system that does not rely on eductors, allowing operation over a wider range of system pressures. EPD and Plant Washington did not consider an alternate, more reliable carbon injection system.

Greater than 90% mercury removal has been achieved on a long term basis at subbituminous coal-fired power plants with activated carbon injection. Based on Plant Washington's and EPD's determination of MACT floor (which we contend is not low enough and doesn't reflect the best emissions control achieved in practice at similar facilities), EPD's MACT floor for mercury at Plant Washington does not even reflect 90% control and fails to reflect what can be achieved with activated carbon or other sorbent testing even considering the use of subbituminous coal. For example, the Holcomb Unit 1 power plant, which burns PRB subbituminous coal, achieved 93% mercury control in long term testing.[268] In addition, over a year of continuous mercury CEMS data is available for the WE Energies Presque Isle facility in Michigan, which burns subbituminous coal, and these data demonstrate that over 90% mercury control has been achieved on a continuous basis. This site is a Department of Energy test site, and the data is thus publicly available. Some of this data has been summarized in presentations and published articles. Exs. 100,[269] 101,[270] 102,[271] 103,[272] and 104.[273] Furthermore, at least two other full-scale, long-term mercury control demonstrations have been reported to continuously achieve 90%+ mercury control – at Rocky Mountain Power (Hardin) in Montana, Ex. 93, and at Comanche Station in Colorado, Ex. 105, both of which burn PRB coal. EPD should obtain the complete record and use it to inform its MACT decision in this case.

Thus, EPD failed to evaluate all available information in determining MACT for the mercury to be emitted by Plant Washington. In addition, the proposed mercury emission limits are less stringent than the emissions control achieved in practice by the best controlled similar source. Consequently, the EPD MACT analysis and proposed MACT limits for mercury are technically and legally deficient.

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[268] *See* Sjostrom, Sharon, *Evaluation of Sorbent Injection for Mercury Control, Topical Report for: Sunflower Electric's Holcomb Station, Reporting Period: October 1, 2003 – June 1, 2005*, June 28, 2005 at 33-34, Ex. 85.

[269] *TOXECON™ Retrofit for Mercury and Multi-Pollutant Control, NETL Mercury Control Technology*, December 13, 2006, Pittsburgh, PA.

[270] *TOXECON™ Clean Coal Demonstration for Mercury and Multi-Pollutant Control*, DOE/NETL Mercury Control Conference 2007, Pittsburgh, PA.

[271] *TOXECON™ Clean Coal Demonstration for Mercury and Multi-Pollutant Control*, EUEC 2008, Tucson, AZ.

[272] Derenne, Steven et. al., *TOXECON™ Demonstration for Mercury and MultiPollutant Control at We Energies*, Paper #08-A-79-MEGA-AWMA.

[273] *TOXECON™ Tests at PIPP Continue Successfully*, PRECIP Newsletter No. 397, February 2009.

d. Other HAPS

EPD did not set limits on any other individual HAPs besides hydrogen chloride, hydrogen fluoride, and mercury. However, it is feasible to set separate limits for individual HAPs. We are aware of several permits that have established limits on many more HAPs than in the Plant Washington permit, including Longview, Ex. 53, and Thoroughbred. Ex. 62. Further, as stated above, EPD is required to set MACT limits for all of the HAPs to be emitted by Plant Washington. *See* 42 U.S.C. § 7412(a)(6).

e. The Proposed Plant Washington MACT Provisions Do Not Include Adequate Testing or Monitoring Requirements.

The proposed permit revisions fail to include adequate testing or monitoring requirements to ensure enforceability and compliance with the proposed MACT limits. Specifically, 40 C.F.R. § 63.43(g)(2) provides in pertinent part as follows:

> (2) The Notice of MACT Approval will specify any notification, operation and maintenance, performance testing, monitoring, reporting and record keeping requirements. The Notice of MACT Approval shall include:
> (i) In addition to the MACT emission limitation or MACT work practice standard established under this subpart, additional emission limits, production limits, operational limits or other terms and conditions necessary to ensure Federal enforceability of the MACT emission limitation;
> (ii) Compliance certifications, testing, monitoring, reporting and record keeping requirements that are consistent with the requirements of §70.6(c) of this chapter;
> (iii) In accordance with section 114(a)(3) of the Act, monitoring shall be capable of demonstrating continuous compliance during the applicable reporting period. Such monitoring data shall be of sufficient quality to be used as a basis for enforcing all applicable requirements established under this subpart, including emission limitations . . . .

The draft permit, as revised, fails to comply with these requirements.

First, the permit fails to include any testing or monitoring, recordkeeping or reporting requirements for mercury during the first year of operation of Plant Washington. While mercury CEMs are required to demonstrate compliance with the proposed rolling 12-month averages (which we support and agree are justified to ensure continuous compliance with emission limits), the permit must include interim monitoring and reporting provisions for the first 12 month of operation (before the first 12 month rolling average is determined) to ensure that Plant Washington is achieving MACT for mercury during that period.

Second, the Permit requires a single stack test for HF and HCl (for each coal type) over the entire life of the Facility. Condition 6.3(d), (f). The Permit also does not define excess emissions, exceedances, or excursions reports for HCl and HF. Condition 7.25. The Notice of MACT Approval at 26 explains that Power4Georgians proposes to use SO_2 CEMS and pH to demonstrate that acid gas pollution control devices are operating effectively. However, the Permit does not detail how this data is to be used to ensure compliance with the acid gas MACT limits. And the permit does not require that SO_2 CEMS and pH data be used to determine compliance with the HCl and HF limits. Thus, the proposed MACT limits for HF and HCl are unenforceable as a practical matter. The advocated indirect monitoring fails to ensure compliance.

There is typically no correlation between sulfur in coal (and hence SO2 in stack gases) and chlorine or fluorine in the coal (and hence HCl and HF in the stack gases). *See* Exs. 19, 20A-C. For example, the chlorine in the coal could triple while the sulfur content remains constant. This could lead to an exceedance of the HCl limit, but no change in SO2 emissions. Thus, the SO2 CEMS does not assure compliance with the HCl and HF emission limits.

Thus, the indirect monitoring is not linked to the underlying permit limit. Neither EPD nor Power4Georgians has measured or supported in any manner the relationship between the parameters being "indirectly" monitored, SO2 and pH, and the plant's HCl and HF emissions. The permit does not, as a result, connect the "indirect" parameters with the plant's HCl and HF limits, even if the plant violates the "indirect" parameters under the terms of the permit, the HCl and HF limits are still satisfied. Moreover, the suggested indirect monitoring fails to measure all of the variables upon which the plant's HCl and HF emissions depend. HCl and HF emissions may vary by orders of magnitude based upon, among other things, fuel selection; yet, the permit does not monitor the chlorine and fluorine content of the plant's fuels or place any restrictions on these fuels. As a result, even if all of the indirectly monitored parameters are satisfied, i.e., the SO2 limits, the plant may still emit pollutants well above the HCl and HF permit limits. Put differently, unless all variables that significantly affect the plant's HCl and HF emissions are monitored, "indirect" monitoring cannot ensure continuous compliance: the permit fails to provide such comprehensive indirect monitoring.

The permit and supporting record fail to establish any relationship between the indicators and the parameters they represent. The EPA has objected to numerous proposed Title V permits based on a permitting authority's failure to adequately establish a correlation between the indicator and the emission limit. For example, EPA objected to the proposed Title V permit for a plant in Florida based in part upon the lack of correlation between VOC emissions and CO/O2 emissions where CO/O2 was being measured as a surrogate for VOCs. In the objection letter, the EPA stated:

> [T]he Title V permit does not contain any detailed explanation linking CO/O2 monitoring to VOC, for the purposes of compliance. To resolve this concern, the permit must require the source to conduct routine VOC monitoring, or a technical demonstration, such as a comparison of

> historical emission data to emission limits, must be included in the statement of basis explaining why the State has chosen to allow CO monitoring as a surrogate for VOC. A discussion of how carbon monoxide monitoring indicates good combustion, which affect VOC emissions, could be provided along with historical data to support the current monitoring strategy.

U.S. EPA Region 4 Objection, Proposed Part 70 Operating Permit, Southdown, Inc – Brooksville Plant, Hernando County, Florida, Permit No. 0530010-002-AV.

Similarly, on December 22, 2000, the EPA granted a petition for objection to a Title V permit based in part upon the fact that the permit and accompanying Statement of Basis failed to provide a sufficient basis for assuring compliance with several permit conditions. *See In re Fort James Camas Mill*, Order Denying in Part and Granting in Part Petition for Objection to Permit, December 22, 2000. According to the Order, "the rationale for the selected monitoring method must be clear and documented in the permit record." *Id.* at 8.

The permit and supporting record must establish a specific link with proffered indicators to assure continuous compliance and enforceability. For example, in the Tampa Electric Company's F.J. Gannon Station case, the EPA objected to the Title V permit, stating:

> While the permit does include parametric monitoring of emission unit and control equipment operation in the O&M plans for these units … the parametric monitoring scheme that been specified is not adequate. The parameters to be monitored and the frequency of monitoring have been specified in the permit, but the parameters have not been set as enforceable limits. In order to make the parametric monitoring conditions enforceable, a correlation needs to be developed between the control equipment parameter(s) to be monitored and the pollutant emission levels. The source needs to provide an adequate demonstration (historical data, performance test, etc.) to support the approach used. In addition, an acceptable performance range for each parameter that is to be monitored should be established. The range, or the procedure used to establish the parametric ranges that are representative of proper operation of the control equipment, and the frequency for re-evaluating the range should be specified in the permit. Also, the permit should include a condition requiring a performance test to be conducted if an emission unit operates outside of the acceptable range for a specified percentage of normal operating time. The Department should set the appropriate percentage of the operating time would serve as trigger for this testing requirement.

U.S. EPA Region 4 Objection, Proposed Part 70 Operating Permit, Tampa Electric Company, F.J. Gannon Station, Permit No. 0570040-002-AV.[274]

The permit offers no link between the proffered indicators and the underlying MACT limits. Thus, if EPD is going to allow these secondary indicators at all, the agency should rewrite the permit to clearly transfer enforceability to the underlying limits – HCl, HF, as well as metals (PM surrogate) and organic HAPs (CO surrogate). By way of example, if SO2 is used to determine continuous compliance with HCl and HF, at the very least, the permit should clearly state that an SO2 violation equals an HCl and HF limit violation.

The permit does not specify that a violation of an indicator constitutes a per se violation of the underlying permit limit. The permit also does not contain an indicator range or the procedure to acquire one. The permit also lacks any requirement to develop a correlation between the indicators and the applicable requirement, support for the chosen approach, a trigger for additional stack testing, a requirement for stack testing if operation occurs outside of the range, or a requirement to cure the exceedance. Thus, the permit does not ensure continuous compliance for HCl, HF, non-mercury metallic HAPs, and organic HAPs.

Continuous emission monitoring systems (CEMS) are available for both HCl and HF and are widely used in other industries. *See, e.g.,* Exs. 113 and 114.[275] While they have not yet been used on coal-fired power plants in the United States to our knowledge,

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[274] *See also* U.S. EPA Region 4 Objection, Proposed Part 70 Operating Permit, Oxy Vinyl, LP, Louisville, Kentucky, Permit NO. 212-99-TV ("For example, a parametric range that is representative of the proper operation of the control equipment could be established using source data to develop a correlation between control parameters(s) and PM emissions. *The permit must specify the parametric range or procedure used to establish that range, as well as the frequency for re-evaluating the range")* (emphasis added); U.S. EPA Region 4 Objection Proposed Part 70 Operating Permit; North County Regional Resource Recovery Facility Permit No. 0990234-001-AV; U.S. EPA Region 4 Objection Proposed Part 70 Operating Permit Pinellas County Resource Recovery Facility Permit No. 1030117-002-AV. These decisions are posted on EPA's website at: *http://www.epa.gov/Region4/air/permits/TitleVObjectionLetters/FL_ObjectionLetters/TECO-JGannon.pdf;http://www.epa.gov/Region4/air/permits/TitleVObjectionLetters/KY_ObjectionLetters/OxyVinyls.pdf; http://www.epa.gov/Region4/air/permits/TitleVObjectionLetters/FL_ObjectionLetters/NorthCoRRR-WestPalm.pdf; and http://www.epa.gov/Region4/air/permits/TitleVObjectionLetters/FL_ObjectionLetters/PinellasCoRR-Clearwater.pdf*

[275] Offerings by Gasmet and Thermo Scientific

as case-by-case MACT limits have only recently been imposed on coal-fired power plants, HCl and HF CEMS are entirely capable of being used on such power plants.

EPA has recently recognized that CEMS are the proper means of measuring compliance with HCl limits; on April 22, 2009, EPA recommended that North Carolina require a HCl CEMS to assure that HCl emissions at Cliffside Unit 6 remain below the MACT applicability threshold. EPA wrote: "[w]hile there are monitoring alternatives to an HCl CEMS, a HCl CEMS is expected to provide the most reliable assurance of compliance." Ex. 115.[276] In addition, Florida recently issued a revised draft permit for the Seminole plant that requires the use of HCl and HF CEMS to demonstrate that emissions remain below 9.75 ton/yr for HCl plus HF combined, which works out to the lowest HCl and HF emissions in any coal plant permit. Exs. 116 and 117.

Continuous emission monitoring is EPA's preferred method of determining continuous compliance and has been required for NOx and SO2 under NSPS for decades. *See*, *e.g.*, NSR Manual, p. I.3 ("Continuous, direct emission measurement is preferable.") CEMS should be used here to determine continuous compliance with the HCl and HF MACT limits.

IV. The Application Must Be Submitted and Reviewed by a Professional Engineer Licensed in Georgia.

No licensed professional engineer, registered in Georgia or otherwise, prepared or reviewed the application and draft permit for Plant Washington. 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

[276] Letter from A. Stanley Meiburg, Acting Regional Administrator, EPA Region 4, to Dee Freeman, Secretary, North Carolina Department of Environment and Natural Resources, April 30, 2009.

> 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). "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 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.

Both the Applicant and EPD make BACT determinations as part of the permitting process. 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.* A MACT determination is made similar to a BACT determination. As such, EPD must ensure that both the BACT and MACT determinations made by the Applicant and the permitting agency are performed by properly licensed professional engineers.

V. Conclusion

For the reasons set forth above, we ask EPD to deny the requested Plant Washington Permit. For your convenience, we have provided all of the source material referenced in these comments. Omissions in exhibit numbers, such as numerical gaps between exhibit numbers, are intentional. All documents referenced as exhibits should be included on the accompanying CD, regardless of such omissions. If you believe that any documents have not been provided, or if you 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,

For GreenLaw:

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Attachments (exhibits and other references cited above)