BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

An Operating Permit for the Wansley Steam-Electric Generating Plant, Heard County, Georgia.

Proposed by the Georgia Environmental Protection Division.

Source I.D. 04-13-149-00001

Permit No. 4911-149-0001-V-03-0

Petition No. V-2012-______

OEA
cc: AIR

PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF THE PROPOSED TITLE V OPERATING PERMIT FOR THE WANSLEY POWER PLANT

Pursuant to Clean Air Act § 505(b)(2) and 40 CFR § 70.8(d), Fall-line Alliance for a Clean Environment, [1] Ogeechee Riverkeeper,[2] Southern Alliance for Clean Energy,[3] and Sierra Club[4] (collectively, "Petitioners") petition the Administrator of

[1] Fall-line Alliance for a Clean Environment ("FACE") is an organization of 200 members and supporters that has been at the forefront of investigation, education, and advocacy for a safe and clean environment for the Middle Georgia area identified geographically as the Fall Line. FACE's primary work focuses on the threat posed by coal-generated power, and specifically the toxic pollutants emitted by coal-fired power plants and impacts from these pollutants on the quality and availability of water supplies. The organization has also been active on issues including landfills, tire incinerators, and land use.

[2] Ogeechee Riverkeeper ("ORK") is membership corporation with approximately 1400 members. ORK's mission is to protect, preserve and improve the water quality of the Ogeechee River basin. One of the pollution concerns in the Ogeechee River basin is due to mercury, which is emitted in large quantities by power plants.

[3] Southern Alliance for Clean Energy ("SACE") has been a leading voice for energy policy to protect the quality of life and treasured places in the Southeast since 1985. http://www.cleanenergy.org/index.php?/Who-We-Are.html.

[4] Sierra Club is a national nonprofit organization with over 1 million members and supporters nationwide. The Georgia chapter has 100,000 members and supporters in Georgia, some of whom live, work, and recreate in the vicinity of Plant Wansley and/or in areas impacted by emissions from the Plant. The mission of Sierra Club is to explore, enjoy and protect the wild places of the earth, practice and promote the responsible use of the Earth's ecosystems and resources, educate and enlist humanity to protect and restore the quality of the natural and human environment, and use all lawful means to carry out these objectives.

the United States Environmental Protection Agency ("U.S. EPA" or "EPA") to object to a proposed Title V Operating Permit for the Wansley Steam-Electric Generating Plant ("Wansley"), Permit Number 4911-149-0001-V-03-0 ("Permit"). The Permit was proposed to U.S. EPA by the Georgia Environmental Protection Division ("GEPD") more than 45 days ago. A copy of the proposed Permit is attached as Exhibit A.

Petitioners provided comments to the GEPD on the draft permit and the revised draft permit. A copy of Petitioners' comments is attached at Exhibit B. GEPD's Statement of Basis (labeled as an Amended Narrative) ("Amended Narrative") including response to comments, is attached as Exhibit C. To Petitioners' knowledge, EPA has not yet objected to the proposed Permit. *See* http://www.epa.gov/region4/air/permits/#Part70 (last visited September 4, 2012).

This Petition is filed within sixty days following the end of U.S. EPA's 45-day review period, as required by Clean Air Act ("CAA") § 505(b)(2).[5] The Administrator must grant or deny this petition within sixty days after it is filed. 42 U.S.C. § 7661d.(b)(2). If the Administrator determines that the Permit does not comply with the requirements of the CAA, or fails to include any "applicable requirement," she must object to issuance of the permit. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.8(c)(1) ("The [U.S. EPA] Administrator will object to the issuance of any proposed permit determined by the Administrator not to be in compliance with applicable

[5] EPA's forty-five (45) day comment period expired on July 8, 2012. The public's time for petitioning the Administrator extends through, at least, September 6, 2012. EPA's List of Georgia Proposed Title V Permits, *available at* http://www.epa.gov/region4/air/permits/georgia.htm (last accessed September 4, 2012) (attached at Exhibit D).

requirements or requirements under this part."). "Applicable requirements" include, *inter alia*, any provision of the Georgia State Implementation Plan ("SIP"), any term or condition of any preconstruction permit issued pursuant to SIP approved permitting program, any standard or requirement under Clean Air Act sections 111, 112, 114(a)(3), or 504, and acid rain program requirements. 40 C.F.R. § 70.2; *In the Matter of Wisconsin Power and Light Columbia Generating Station*, Petition Number 2008-1, Order Responding to Petitioner's Request that the Administrator Object to Issuance of State Operating Permit, at 5, 10 ("Columbia Generating Station"). Additionally, because this Petition establishes that the Permit fails to assure compliance with applicable requirements and contains material errors and inaccurate or unclear statements, EPA must reopen and revise the permit pursuant to 42 U.S.C. § 7661d(e) and 40 CFR §§ 70.7(g) and 70.8.

As set forth below, the Administrator should object to the Permit for the following reasons:

1. The Permit lacks sufficient monitoring to assure compliance for particulate matter ("PM") emissions. By concluding that no better than once-every-five-year stack testing was sufficient to assure compliance, by failing to provide rationale supporting this decision, and by failing to include any additional or alternative particulate matter monitoring sufficient to provide reliable data sufficient to determine compliance on a continuous basis, GEPD failed to meet the minimum monitoring requirements under Title V and Part 70.
2. The Permit lacks sufficient monitoring to assure compliance for SO_2. By including language that may exempt the facility from continuous emissions monitoring systems ("CEMS") operation during startup, shutdown, and malfunction periods, and by responding with inadequate discussion on this issue that further confuses the issue by stating that recording of information is not required during these periods, GEPD failed to meet the minimum monitoring requirements under Title V and Part 70.
3. The Permit contains inadequate provisions addressing hazardous air pollutants ("HAPs") under recently promulgated regulations. GEPD failed to

include detailed information as to how the facility must comply with these regulations. As a result, the Permit fails to include applicable limitations.

4. The Permit contains inadequate provisions addressing fugitive dust from the coal handling systems. By failing to include specifically enforceable best management practices, GEPD has ignored the language of its SIP. As a result, the Permit fails to include these practices to limit fugitive emissions.

I. THE PERMIT CONTAINS INSUFFICIENT MONITORING REQUIREMENTS.

The Clean Air Act, Title V implementing regulations, and Georgia regulations mandate that Title V Permits incorporate terms sufficient to assure compliance with applicable limitations. The Permit contains insufficient monitoring requirements to assure compliance with these limitations, and for this reason the EPA must object to the Permit and require that it be revised to include sufficient monitoring requirements.

The CAA requires that permits "shall set forth . . . monitoring . . . requirements sufficient to assure compliance" with emissions limits in a Title V permit. 42 U.S.C. § 7661c(c). EPA has promulgated regulations in Part 70 that describe the steps permitting authorities must take to fulfill the monitoring requirement from section 504(c). *See* 40 C.F.R. §§ 70.6(a)(3)(i)(A), 70.6(a)(3)(i)(B), and 70.6(c)(1). The D.C. Circuit in *Sierra Club v. EPA* described the Part 70 rules as requiring three steps to establish periodic monitoring requirements in each Title V permit issued:

> (1) where there are monitoring requirements already contained in existing regulations or permits, the permitting authority must incorporate those requirements into the permit;

(2) where no previously established monitoring requirements exist for an emission limit, the permitting authority must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit;" and

(3) where monitoring requirements exist that correspond to an emission limit, but that monitoring is not sufficient to assure compliance with the permit limit, the permit writer must remedy that deficiency by supplementing inadequate monitoring to make the requirement sufficient to assure compliance.

See Sierra Club v. EPA, 536 F.3d 673, 675 (D.C. Cir. 2008); *see also In re United States Steel Corporation – Granite City Works*, Petition No. V-2009-03, Order Responding to Petitioner's Request that the Administrator Object to Issuance of State Operating Permit, at 5-7 ("U.S. Steel").

In addition to setting forth adequate monitoring requirements for emission limits, the permitting authority is required to set forth its rationale in a statement of basis describing why the chosen monitoring regime is adequate to assure compliance with the emissions limit. 40 C.F.R § 70.7(a)(5); *U.S. Steel* at 7. The determination of what monitoring is adequate is a context-specific exercise. *U.S. Steel* at 7. EPA has described the permit writer's monitoring analysis as *beginning* by "assessing whether the monitoring required in the applicable requirement is sufficient to assure compliance with the permit terms and conditions." *Id.*

Appropriate factors for the permit writer to consider include: (1) variability of emissions from the unit in question; (2) likelihood of violation of the requirements; (3) whether add-on controls are being used for the unit to meet the emission limit; (4) the type of monitoring, process, maintenance, or control equipment data already available for the emission unit; and (5) the type and frequency of the monitoring requirements for similar emission units at other facilities. *Id.* Similarly, the *Sierra Club* court indicated that frequency of emissions monitoring must reflect the averaging time used to determine compliance. *Sierra Club*, 536 F.3d at 765 (a yearly monitoring requirement would not likely adequately address a daily maximum emission limit); *see also* U.S. EPA, Objection to Proposed Title V Operating Permit for TriGen-Colorado Energy Corporation (Sept. 13, 2000) ("a one-time test does not satisfy the periodic monitoring requirements").

Petitioners commented on two provisions of the Wansley Permit where monitoring requirements are insufficient to ensure compliance: the provisions requiring stack test monitoring for particulate matter ("PM"), and provisions regarding startup, shutdown and malfunction ("SSM"). Comments at sections VII.a, and VII.b.

A. The Permit's PM Monitoring Provisions Must be Strengthened.

The Permit, requiring demonstration of compliance with PM limits via stack test every five years on the scrubber stack and following 8760 operating hours or five years on the bypass stack, is insufficient to assure continuous compliance with hourly PM limitations. Permit at 4.2.1. The permits should be revised to include more stringent monitoring requirements. The best option for adequate monitoring would require PM CEMS, but at a minimum the Permit must include frequent PM stack tests, e.g. quarterly, and the use of continuous parametric or surrogate monitoring with site specific correlations established during each stack test.

The PM emission standard for Wansley is derived from Georgia Comp. R. & Regs. r. 391-3-1-.02(2)(d)1(iii), and prohibits the emission of "particulate matter in excess of 0.24 lb/MMBtu" from any steam generating unit. Permit at 3.4.1. The Georgia SIP does not contain provisions requiring specific types of PM monitoring, so the permitting authority must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." *Sierra Club*, 536 F.3d at 675; Georgia Comp. R. & Regs. r. 391-3-1-.02(2)(d)1(iii); 40 C.F.R. § 70.6(a)(3)(i)(B).

However, the monitoring frequency required by the Permit is not adequate to assure compliance with the hourly limits. The Permit provides that compliance with the facility's PM limit is demonstrated via stack test on the scrubber stacks every five years; and on the scrubber bypass stack following 8760 operating hours or 60 months, whichever comes first. Permit at condition 4.2.1. Neither the Permit, nor GEPD's responses to Petitioners' comments, provide detailed rationale as to why GEPD thinks that the chosen method is sufficient to assure compliance. *See* Permit; Amended Narrative at Addendum 6. Rather GEPD states that there are no requirements to install CEMS and that continuous opacity monitoring systems ("COMS") are sufficient. Amended Narrative at Addendum 6. Perhaps most importantly, GEPD's response to comments completely fails to discuss, much less try to establish, a correlation between opacity limits and PM limits at the Wansley units. *Id.*

As discussed above, EPA has already found that such infrequent monitoring is insufficient to assure compliance with the limitations provided in the Permit. *U.S. Steel*. Specifically, the EPA found that PM compliance testing once every permit cycle (5 years) was facially insufficient to assure compliance with continuous limitations. *Id.* Further, the EPA found that, because the permitting authority did not provide rationale in the permit record in a "clear and documented" manner "sufficient . . . to demonstrate how the monitoring requirements in the [] permit assure compliance," the permit had to be revised to address this issue. *Id.* at 7-8.

While this analysis is squarely on point with the Permit and counsels revision of its terms, an analysis of the *U.S. Steel* factors also shows that such infrequent monitoring is unlawful. *See U.S. Steel* at 7. First, factors one and three, concerning the variability of emissions, especially as they relate to the add-on controls used by Plant Wansley, strongly indicate the necessity for continuous monitoring. The facility employs electrostactic precipitators ("ESPs") to control particulate matter, which can affected on an order of magnitude by a number of factors related to the fuel, flyash, and the ESP itself. Permit at page 3; *See also* Declaration of Ranajit (Ron) Sahu (attached at Exhibit E).[6] Further, companies often arrange to do "diagnostic tests" before the scheduled "official stack test," which allows time to repair and clean the ESPs to ensure that the ESPs "pass" the stack test, even though particulate matter emissions may be much greater than the rest of the period between stack tests. However, even with the possibility of these

[6] This declaration was created to support a Petition filed in connection with RRI Energy Mid Atlantic Power Holdings LLC, Shawville Generating Station, ID No. 17-00001. However, the type of facility and issues presented in that case are similar to the issues presented in the Wansley Permit.

"diagnostic tests," the variability between runs and stack tests is significant at Plant Wansley: the October 30, 2008 stack test on Unit 1 showed a percent change of 65% between runs 3 and 1; variability between the Unit 2 stack tests on May 20, 2009 and September 24, 2008 shows a percent change of 130.6%.

Additionally, as to factors 4 and 5, PM CEMs are increasingly employed at other coal-fired power plants. For example, American Electric Power Company and Southwestern Power Company ("SWEPCO") have agreed to install PM CEMS at an existing coal-fired power plant. *See* American Electric Power Company, Inc. and SWEPCO Consent Decree at 5-7. The EPA has also secured commitments from up to 30 existing coal-fired utility installations to install PM CEMS within the next few years. *See* Comment Letter Regarding Robinson Power Company Waste-Coal-Fired Power Generation Facility from David Campbell, Chief Permits and Technical Assessments Branch, United States Environmental Protection Agency Region III to Thomas Joseph, Pennsylvania Department of Environmental Protection at 6 (March 11, 2005). Given the use, reliability, and accuracy of monitoring requirements for similar emission units at other facilities, EPA should object to the Permit and require the use of PM CEMS or other PM monitoring such as quarterly stack tests and parametric or surrogate monitoring based on correlations established during each stack test at Wansley.

B. The Permit Should Clearly Require SO_2 CEMS Operation During All Periods of Operation except CEMS Breakdown and Repair.

Additionally, as Petitioners noted in their comments on the Permit, it is unclear in the Permit whether operation of SO_2 CEMS is required during startup, shutdown and malfunction. Comments at section VI.b.iii. As the SO_2 CEMS is required in connection with SO_2 limitations, allowing the facility to cease operation of the SO_2 CEMS during such time periods would be insufficient to "assure compliance" with those limitations. Permit at conditions 3.4.13–3.4.14. Accordingly, the Permit should be revised to include language clearly requiring SO_2 CEMS operations at all times, including during startup, shutdown and malfunction.

The ambiguity results from the inclusion of a deceptively simple clause within Permit provision 5.2.14. The language of this provision appears straightforward at first, seemingly requiring SO_2 CEMS to be "operated and data recorded during all periods of operation . . . including periods of startup, shutdown, malfunction or emergency conditions." Permit at condition 5.2.14. However, Condition 5.2.14 also exempts "any period allowed under Georgia Rule 391-3-1-.02(2)(uuu)(4)", which lists periods of "black starts" and scheduled or preventive maintenance as well as during periods of startup, shutdown or malfunction provided such episodes are consistent with the air quality rule governing allowable "excess emissions," Rules 391-3-1-.02(2)(a)7; 391-3-1-.02(2)(uuu)(4).

EPD's response to Petitioners' comment does not address this issue. Although GEPD states that the Permit's conditions "require the facility to operate the SO_2 CEMS and record data during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions," it then repeats similar language from the permit, concluding that "no change will be made" because "[t]he permit conditions are taken directly from the rules." Amended Narrative at Addendum 7. GEPD does not provide any reasoning to show how excluding these periods assures compliance with the 95% reduction of SO_2 required in the permit. *Id.* GEPD also does not address 40 C.F.R. § 70.6(c)(1)'s requirement to supplement inadequate monitoring.

Given the failure of GEPD to address this issue, EPA should object to the Permit and require Plant Wansley to run SO_2 CEMS during all periods (including startup, shutdown and malfunction) and to collect and record data during all periods of CEMS operation.

II. The Permit Should Include Detailed Requirements for Hazardous Air Pollutant ("HAP") Standards.

As noted above, CAA 504(a) requires each Title V permit to "assure compliance with applicable requirements of this chapter. . . ." 40 C.F.R. § 70.2 defines "applicable requirements" as including "requirements that have been promulgated or approved by EPA through rulemaking at the time of issuance but have future effective compliance dates."

On February 16, 2012, the EPA issued National Emission Standards for Hazardous Air Pollutants ("NESHAPs") for coal-fired electric steam generating units ("EGU MACT") and proposed revisions to the New Source Performance Standards ("NSPS") for these sources. This rule became effective as of April 16, 2012.[7] Since the Wansley Permit was issued on May 8, 2012, the permit must include provisions incorporating this rule.

GEPD's response is inadequate to address the new EGU MACT. GEPD did add Condition 3.3.6 that makes a generic reference to the EGU MACT. Petitioners

[7] Although a partial stay of this rule was issued on August 2, 2012, that stay only relates to new or modified sources. 77 Fed. Reg. 45967, 45968.

were obviously not able to comment on Condition 3.3.6 during the comment period because it did not exist at that point. Having now reviewed Condition 3.3.6, we have determined that EPA should object to the Permit because it fails to include the specific requirements of the EGU MACT, and to include provisions to add any additional monitoring required by 40 C.F.R. § 70.6(c)(1).

III. THE PERMIT MUST INCLUDE PROVISIONS TO CONTROL FUGITIVE DUST FROM THE COAL HANDLING SYSTEM.

Petitioners' comments pointed out that the Wansley Permit does not include or meet SIP requirements because it does not include the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust from the materials handling system. Comments at section VIII. GEPD's response to these comments only addresses requirements to record actions taken, but does not address Petitioners' concern that the Wansley Permit only requires the plant to take "reasonable precautions" which is so vague as to be unenforceable. Amended Narrative at Addendum 7; Permit at condition 3.4.5.

The Wansley Permit subjects the coal handling system to an opacity limit of twenty percent as required by Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n)2, but does not include the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust from this component of the plant. The Georgia SIP includes a non-exhaustive list of specific control devices and practices that should be applied to this facility and detailed in its Title V permit as enforceable conditions of its operation. Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n). These include the application of water or other dust suppressants on surfaces or operations that can give rise to airborne dust, and "[i]nstallation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials." Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n)1.

The Permit does not include any of the listed best management practices. Permit at condition 3.4.5. Rather, GPC is only required to take "reasonable precautions." *Id.* This requirement is vague and unenforceable.

In the Permit, GEPD has ignored the language of the SIP by failing to incorporate specific control devices and practices. EPA should object and require devices to be described in more detail in the Permit, and require monitoring and reporting of these devices as well as to demonstrate compliance with a twenty percent opacity limit, so that the public can evaluate their efficacy and, when necessary, seek enforcement of any violations. The required frequency, quantity and duration of dust suppression techniques should also be included in the Wansley Permit.

Conclusion

For the foregoing reasons, the Permit fails to meet federal requirements in numerous ways. These deficiencies require that the Administrator object to issuance of the Permit pursuant to 40 C.F.R. § 70.8(c)(1). Additionally, each of the reasons for objection, above, also constitutes a basis for mandatory reopening and revision of the Permit pursuant to 42 U.S.C. § 7661d(e), 40 C.F.R. § 70.7(g) and 70.8. Each of the issues raised by Petitioners in this petition result in a deficient permit. Most of the deficiencies result in unlawful emissions of air pollutants that negatively affect the health and welfare of Petitioners' members. Others result in illegal monitoring and reporting that make it difficult for Petitioners to monitor and enforce air pollution limits applicable to the plant.

Dated this 5th day of September, 2012.

Attorney for Petitioners,

Ashten Leigh Bailey

Ashten Bailey

GREENLAW
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104 Marietta Street, Suite 430
Atlanta, Georgia 30303

CERTIFICATE OF SERVICE

On this day I caused to be served upon the following persons a copy of Petitioners' Petition to the United States Environmental Protection Agency regarding the Wansley Power Plant, Permit No. 4911-149-0001-V-03-0

To Administrator Jackson via electronic mail to: jackson.lisa@epa.gov

And via Certified Mail, Return Receipt Requested to:

Lisa Jackson
US EPA Administrator
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Gwendolyn Keyes Fleming
Regional Administrator, United States Environmental Protection Agency Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, GA 30303-8960

Judson H. Turner
Director, Georgia Environmental Protection Division
2 Martin Luther King Jr. Drive, SE Suite 1152 East Floyd Tower
Atlanta, GA 30334-9000

Ron Shipman
Vice President of Environmental Affairs, Georgia Power
241 Ralph McGill Blvd., NE, Bin 10221
Atlanta, GA 30308-3374

Dated: September 5, 2012.

Ashten Leigh Bailey

Ashten Bailey

EXHIBIT A

Part 70 Operating Permit

Permit Number: **4911-149-0001-V-03-0** **Effective Date:** **July 26, 2012**

Facility Name: **Wansley Steam – Electric Generating Plant**

Facility Address: 1371 Liberty Church Road
Carrollton, GA 30116, Heard County

Mailing Address: 241 Ralph McGill Blvd. N.E., Bin 10221
Atlanta, GA 30308

Parent/Holding Company: Southern Company/Georgia Power

Facility AIRS Number: 04-13-149-00001

In accordance with the provisions of the Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq and the Georgia Rules for Air Quality Control, Chapter 391-3-1, adopted pursuant to and in effect under the Act, the Permittee described above is issued a Part 70 Permit for:

> The operation of an electric utility plant including two steam electric generating units and one simple cycle combustion turbine.

This Permit is conditioned upon compliance with all provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq, the Rules, Chapter 391-3-1, adopted and in effect under that Act, or any other condition of this Permit. Unless modified or revoked, this Permit expires five years after the effective date indicated above.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above, for any misrepresentation made in Title V Application No. TV-20541 signed on June 27, 2011, any other applications upon which this Permit is based, supporting data entered therein or attached thereto, or any subsequent submittal of supporting data, or for any alterations affecting the emissions from this source.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached **57** pages.

[Signed]

Director
Environmental Protection Division

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PART 1.0 FACILITY DESCRIPTION

1.1 Site Determination

Plant Wansley is currently contracting with an ash processing facility located on site to process and sell some of the coal ash produced from the electric generating process at Plant Wansley. Even though the ash processing facility and Plant Wansley are located on contiguous property, they are deemed to be separate sources for purposes of Title V permitting due to the fact that there is no common control between Georgia Power Company and the ash processing facility. Therefore, the Title V permit for Plant Wansley covers only those operations controlled solely by Georgia Power. The ash processing facility, which is itself a minor source under 40 CFR Part 70, will continue to operate under its minor source SIP permit.

The Wansley Steam-Electric Generating Plant (AFS No. 149-00001), Southern Power - Wansley Combined-Cycle Generating Plant (AFS No. 149-00011), Oglethorpe Power Corporation – Chattahoochee Energy Facility (AFS No. 149-00006), and the Municipal Electric Authority of Georgia – Wansley Unit 9 (AFS No. 149-00007) are permitted separately. Collectively, they comprise the same Title V site. However, each separate owner/operator is only accountable, for compliance purposes, for the individual electrical generating units that they own or operate.

1.2 Previous and/or Other Names

This facility is commonly known and referred to as Plant Wansley. No other names were identified.

1.3 Overall Facility Process Description

Plant Wansley burns fossil fuel to generate electricity. This facility includes two steam electric generating units which primarily burn coal and one simple cycle combustion turbine which burns No. 2 fuel oil. Each steam generating unit exhausts through its own stack liner in the 675-ft stack. The combustion turbine has its own exhaust which is 32- ft tall.

Southern Power owns two combustion turbine combined-cycle blocks. All of the applicable permit conditions have been moved to Title V Permit 4911-149-0011-V-01-0.

PART 2.0 REQUIREMENTS PERTAINING TO THE ENTIRE FACILITY

2.1 Facility Wide Emission Caps and Operating Limits

None applicable.

2.2 Facility Wide Federal Rule Standards

None applicable.

2.3 Facility Wide SIP Rule Standards

None applicable.

2.4 Facility Wide Standards Not Covered by a Federal or SIP Rule and Not Instituted as an Emission Cap or Operating Limit

None applicable.

PART 3.0 REQUIREMENTS FOR EMISSION UNITS

Note: Except where an applicable requirement specifically states otherwise, the averaging times of any of the Emissions Limitations or Standards included in this permit are tied to or based on the run time(s) specified for the applicable reference test method(s) or procedures required for demonstrating compliance.

3.1 Emission Units

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
SG01	Steam Generator Unit 1	40 CFR 63 Subpart A 40 CFR 63 Subpart UUUUU 391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu), and Acid Rain	3.2.1, 3.2.2, 3.2.6, 3.3.6, 3.4.1, 3.4.2, 3.4.3, 3.4.7, 3.4.8, 3.4.9, 3.4.10, 3.4.13, 3.4.14, 3.4.15	EP01 SCR1 FGD1	ESP SCR FGD
SG02	Steam Generator Unit 2	40 CFR 63 Subpart A 40 CFR 63 Subpart UUUUU 391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu), and Acid Rain	See SG01	EP02 SCR2 FGD2	ESP SCR FGD
CT5A	Combustion Turbine Unit 5A	40 CFR 60 Subpart A 40 CFR 60 Subpart GG 391-3-1-.02(2)(b) and (g) 391-3-1-.02(2)(nnn)(7) 40 CFR 63 Subpart YYYY	3.2.3, 3.2.5, 3.3.1, 3.3.2, 3.3.3, 3.4.2, 3.4.11	WI5A	Water Injection
SB01	Start-up Boiler Unit 1	391-3-1-.02(2)(b), (d), and (g) 40 CFR 63 Subpart A 40 CFR 63 Subpart DDDDD	3.2.4, 3.3.5, 3.4.2, 3.4.3, 3.4.4	none	n/a
SB02	Start-up Boiler Unit 2	391-3-1-.02(2)(b), (d), and (g) 40 CFR 63 Subpart A 40 CFR 63 Subpart DDDDD	See SB01	none	n/a
CHS	Coal Handling System	391-3-1-.02(2)(n)	3.4.5, 3.4.6	none	n/a
AHS	Ash Handling System	391-3-1-.02(2)(n)	See CHS	none	n/a
MHS	Materials Handling System	391-3-1-.02(2)(e) 391-3-1-.02(2)(n) 40 CFR 60 Subpart A 40 CFR 60 Subpart OOO	3.3.4, 3.4.5, 3.4.6, 3.4.12	none	n/a

* Generally applicable requirements contained in this permit may also apply to emission units listed above. The lists of applicable requirements/standards and corresponding permit conditions are intended as a compliance tool and may not be definitive.

3.2 Equipment Emission Caps and Operating Limits

3.2.1 The Permittee shall not fire any fuel other than coal in the steam generating units (Emission Unit IDs SG01 and SG02) except for the following:
[391-3-1-.03(2)(c)]

a. No. 2 fuel oil, biodiesel, or biodiesel blends may be burned for start-up, shutdown, to assist in achieving peak load, and flame stabilization.

b. Sawdust may be blended and fired with the coal.

c. Biomass may be blended and fired with the coal. Biomass, as used in this permit, shall include, but not be limited to paper, vegetative matter, or wood chips. Biomass shall not include sawdust (sawdust is covered by 3.2.1b.) or municipal solid waste except as may be specifically listed above.

d. Used oil, as indicated in Condition 3.2.2, may be burned.

e. Coal-derived synthetic fuel, manufactured using a binder with mercury of content less than or equal to 0.2 ppm on a dry basis and the binder constitutes approximately 2.5% by weight or less of the coal-derived synthetic fuel shall be considered coal for the purposes of this permit.

State Only Enforceable

3.2.2 The Permittee shall not burn used oil in any steam generating unit (Emission Unit IDs SG01 and SG02) during periods of startup or shutdown. For the purposes of this permit, startup shall be defined as the period lasting from the time the first oil fire is established in the furnace until the time that mill/burner performance and secondary air temperature are adequate to maintain an exiting gas temperature above the sulfuric acid dew point. Shutdown means the cessation of the operation of a source or facility for any purpose. [391-3-1-.03(2)(c)]

3.2.3 The Permittee shall not fire any fuel other than No. 2 fuel oil, biodiesel, biodiesel blends, or propane in the combustion turbine (Emission Unit ID CT5A). [391-3-1-.03(2)(c)]

3.2.4 The Permittee shall not fire any fuel other than No. 2 fuel oil, biodiesel, biodiesel blends, or propane in the start-up boilers (Emission Unit IDs SB01 and SB02). [391-3-1-.03(2)(c)]

3.2.5 The Permittee shall limit the hours of operation of the combustion turbine (Emission Unit ID CT5A) such that the hours of operation does not exceed 500 hours during any twelve consecutive months. [391-3-1-.03(2)(c)]

NOx Emission Limit for the 7-Plant Plan

3.2.6 The Permittee shall not discharge, or cause the discharge, into the atmosphere NOx emissions, including emissions occurring during startup and shutdown, from the combined operations of all affected units (Emission Unit IDs SG01, SG02, SG03, SG04 at Plant Bowen (AFS No. 015-00011); SG01, SG02, SG03, SG04 at Plant Branch (AFS No. 237-00008); SG01, SG02, SG03, SG04 at Plant Hammond (AFS No. 115-00003); SGM1, SGM2 at Plant McDonough (AFS No. 067-00003); SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008); SG01, SG02 at Plant Wansley (AFS No. 149-00001); and SG01, SG02, SG03, SG04, SG05, SG06, SG07 at Plant Yates (AFS No. 077-00001)) in excess of 32,335.8 tons during the ozone season. For purposes of this permit, the ozone season shall be defined as May 1 through September 30. [391-3-1-.03(8)(c)1 and 391-3-1-.03(8)(c)15]

3.3 Equipment Federal Rule Standards

3.3.1 The Permittee shall comply with all applicable provisions of the New Source Performance Standards (NSPS) as found in 40 CFR 60, in particular Subpart A "General Provisions" and Subpart GG - "Standards of Performance for Stationary Gas Turbines," for the operation of the combustion turbine (Emission Unit ID CT5A).
[40 CFR 60 Subparts A and GG]

3.3.2. The Permittee shall not discharge or cause the discharge into the atmosphere from the combustion turbine (Emission Unit ID CT5A) any gases which contain nitrogen oxides in excess of:
[40 CFR 60.332(a)(1)]

$$STD = 0.0075 \times (14.4/Y) + F$$

where:

STD equals the allowable nitrogen oxides concentration (percent by volume @ 15% oxygen and on a dry basis.

Y equals the manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F equals the nitrogen oxides emission allowance for fuel-bound nitrogen as defined in 40 CFR 60.332(a)(3).

3.3.3 The Permittee shall not fire any fuel oil in the combustion turbine (Emission Unit ID CT5A) that contains greater than 0.5 percent sulfur, by weight.
[391-3-1-.03(2)(c), 40 CFR 60.333(b) (subsumed), and 391-3-1-.02(2)(g)1(i) (subsumed)]

3.3.4 The Permittee shall comply with the detailed provisions of 40 CFR 60 Subpart OOO, "Standards of Performance of Nonmetallic Mineral Processing Plants" for the affected portion of the materials handling system (Emission Unit ID MHS). The affected portion shall include any grinding mill, screening operation, belt conveyor, and storage bin associated with the limestone handling process. In particular, the Permittee shall not discharge, or cause the discharge, into the atmosphere,
[40 CFR 60 Subpart OOO]

a. from any crusher, at which a capture system is not used, any fugitive emissions which exhibit greater than 15 percent opacity.

b. from any stack, emissions which contain particulate matter in excess of 0.05 g/dscm (0.022 grains/dscf) or exhibit greater than 7 percent opacity. This shall become effective on and after the date the performance test is performed.

c. from any screening operation, belt conveyor transfer point, bagging operation, storage bin, enclosed truck or railcar loading station, or from any other affected equipment any fugitive emissions which exhibit greater than 10 percent opacity.

d. any visible emissions from;

i. wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to the next crusher, grinding mill or storage bin and,

ii. screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, where such screening operations, bucket elevators, and belt conveyors process saturated materials up to the first crusher, grinding mill, or storage bin in the production line.

For processing equipment subject to Subpart OOO located inside a building, the Permittee shall comply with the above process limits (a, b, c, and d), or shall not discharge or cause the discharge into the atmosphere, any

e. visible fugitive emissions from the building may not exhibit greater than 7 percent opacity

f. emissions from a powered building vent which contain particulate matter in excess of 0.05 g/dscm (0.022 grains/dscf) or exhibit greater than 7 percent opacity.

Note: Unloading of nonmetallic minerals from movable vehicles designed to transport nonmetallic minerals from one location to another, including but not limited to: trucks, front end loaders, skip hoists, and railcars into any screening operation, feed hopper, or crusher is exempt from the requirements of this condition.
[40 CFR 60 Subpart OOO, 40 CFR 60.672(d)]

3.3.5 The Permittee shall comply with all applicable provisions of 40 CFR 63 Subpart A: General Provision and 40 CFR 63 Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants: Industrial, Commercial, and Institutional Boilers and Process Heaters for the operation of the startup boilers (Emission Unit IDs SB01 and SB02).
[40 CFR 63 Subpart A and DDDDD]

3.3.6 The Permittee shall comply with all applicable provisions of the "National Emission Standards for Hazardous Air Pollutants" as found in 40 CFR 63, Subpart A, "General Provisions" and 40 CFR 63, Subpart UUUUU, "National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units" for operation of the Steam Generating Units (Emission Unit IDs SG01 and SG02).
[40 CFR 63, Subparts A and UUUUU]

3.4 Equipment SIP Rule Standards

3.4.1 The Permittee shall not discharge or cause the discharge into the atmosphere from any steam generating unit (Emission Unit IDs SG01 or SG02) any gases which contain particulate matter in excess of 0.24 lb/MMBtu heat input.
[391-3-1-.02(2)(d)1(iii)]

3.4.2 The Permittee shall not discharge or cause the discharge into the atmosphere from any steam generating unit (Emission Unit IDs SG01 or SG02), the combustion turbine (Emission Unit ID CT5A), or start-up boiler (Emission Unit IDs SB01 or SB02) any gases which exhibit opacity equal to or greater than 40 percent.
[391-3-1-.02(2)(b)]

3.4.3 The Permittee shall not fire any fuel in any steam generating unit (Emission Unit IDs SG01 or SG02) or start-up boiler (Emission Unit IDs SB01 or SB02) that contains greater than 3.0 percent sulfur, by weight.
[391-3-1-.02(2)(g)2]

3.4.4 The Permittee shall not discharge or cause the discharge into the atmosphere from any start-up boiler (Emission Unit IDs SB01 or SB02) any gases which contain particulate matter in excess of the rate derived from $E = 0.7 \times (10/R)^{0.202}$ where E equals the allowable particulate emission rate in pounds per million Btu heat input and R equals the heat input in million Btu per hour.
[391-3-1-.02(2)(d)1(ii)]

Coal, Ash, and Materials Handling Requirements

3.4.5 The Permittee shall take all reasonable precautions with the coal handling system (Emission Unit ID CHS), the ash handling system (Emission Unit ID AHS), and the materials handling system (Emission Unit ID MHS) to prevent fugitive dust from these operations from becoming airborne.
[391-3-1-.02(2)(n)1]

3.4.6 The percent opacity from the coal handling system (Emission Unit ID CHS), the ash handling system (Emission Unit ID AHS), and those portions of the materials handling system (Emission Unit ID MHS) not covered by 3.3.4 shall not equal or exceed 20 percent.
[391-3-1-.02(2)(n)2]

NOx Emission Limits per Georgia Rule (jjj)

3.4.7 Except as indicated in Condition Nos. 3.4.9 and 3.4.10, the Permittee shall not discharge, or cause the discharge, into the atmosphere from steam generating unit with Emission Unit ID SG01 at Plant Wansley (AFS No. 149-00001) NOx emissions in excess of 0.07 lb/MMBtu heat input on a 30-day rolling average period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)3(i)]

3.4.8 Except as indicated in Condition Nos. 3.4.9 and 3.4.10, the Permittee shall not discharge, or cause the discharge, into the atmosphere from steam generating unit with Emission Unit ID SG02 at Plant Wansley (AFS No. 149-00001) NOx emissions in excess of 0.07 lb/MMBtu heat input on a 30-day rolling average period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)3(i)]

3.4.9 If the Permittee does not comply with Condition Nos. 3.4.7 or 3.4.8, the Permittee shall demonstrate that NOx emissions, averaged over all affected units (Emission Units IDs SG01, SG02, SG03, SG04 at Plant Bowen (AFS No. 015-00011); SG01, SG02, SG03, SG04 at Plant Hammond (AFS No. 115-00003); SGM1, SGM2 at Plant McDonough (AFS No. 067-00003); SG01, SG02 at Plant Wansley (AFS No. 149-00001); and SG01, SG02, SG03, SG04, SG05, SG06, SG07 at Plant Yates (AFS No. 077-00001)), do not exceed 0.13 lb/MMBtu heat input on a 30-day rolling averaging period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)3(ii)]

3.4.10 If the Permittee does not comply with Condition Nos. 3.4.7 or 3.4.8, the Permittee shall demonstrate that NOx emissions, averaged over all affected units (Emission Units IDs SG01, SG02, SG03, SG04 at Plant Bowen (AFS No. 015-00011); SG01, SG02, SG03, SG04 at Plant Branch (AFS No. 237-00008); SG01, SG02, SG03, SG04 at Plant Hammond (AFS No. 115-00003); SGM1, SGM2 at Plant McDonough (AFS No. 067-00003); SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008); SG01, SG02 at Plant Wansley (AFS No. 149-00001); and SG01, SG02, SG03, SG04, SG05, SG06, SG07 at Plant Yates (AFS No. 077-00001)), do not exceed 0.18 lb/MMBtu heat input on a 30-day rolling averaging period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)5(ii)]

Georgia Rule (nnn)

3.4.11 The Permittee shall only operate combustion turbine CT5A under the following conditions from May 1 through September 30 of each year. This condition shall be State Only Enforceable until EPA approval of Georgia Rule 391-3-1-.02(2)(nnn)7 as submitted in EPD's Atlanta attainment SIP, at which time it becomes federally enforceable.
[391-3-1-.02(2)(nnn)7]

a. For purposes of routine testing, to maintain operability, not to exceed three (3) hours per month.

b. For the purpose of restarting the steam-electric generating units (Emission Unit ID Nos. SG01 and SG02) when all steam-electric generating units at a facility are down and off-site power is not available (also known as a "Black Start"). Or, when power problems on the grid would necessitate implementing manual load shedding procedures for retail customers (Note: This does not apply to special rate structure conditions).

3.4.12 The Permittee shall not discharge, or cause the discharge, into the atmosphere from the Material Handling System (Emission Unit ID. No. MHS) any gases which contain particulate matter in excess of the rate derived from the equation noted below:
[391-3-1-.02(2)(e)(1)]

a. For process input weight rate up to and including 30 tons per hour:
$E = 4.1P^{0.67}$; or

b. For process input weight rate above 30 tons per hour:
$E = 55P^{0.11} - 40$

where E equals the allowable PM emission rate in pounds per hour and P equals the total dry process input weight rate in tons per hour.

SO_2 Emission Limits Per Georgia Rule (uuu)

3.4.13 With the exception of periods indicated in Condition No. 3.4.14, the Permittee shall not discharge, or cause the discharge, into the atmosphere from steam generating units with emission unit IDs SG01 and SG02 at Plant Wansley (AFS No. 149-00001), any gases which contain SO_2 emissions in excess of 5 percent (0.05) of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.
[391-3-1-.02(2)(uuu)2]

3.4.14 For purposes of this permit, requirements in Condition 3.4.13 do not apply during the following periods.
[391-3-1-.02(2)(uuu)4]

a. Restarting of an Electric Utility Steam Generating Unit when all Electric Utility Steam Generating Units at the facility are down and off-site power is not available (also known as a “Black Start”).

b. Periods of startup of an Electric Utility Steam Generating Unit provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

c. Periods of shutdown of an Electric Utility Steam Generating Unit provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

d. Periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage of the respective Electric Utility Steam Generating Unit.

e. Periods of malfunction of an Electric Utility Steam Generating Unit and/or control technology equipment provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

f. Periods when the Permittee is required to conduct the Relative Accuracy Test Audit (RATA) and any other necessary periodic quality assurance procedures on the Continuous Emissions Monitoring System (CEMS) located on the bypass stack pursuant to 40 CFR Part 75 or the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**.

g. Periods when the Permittee is required to conduct any performance testing on the bypass stack as required by State or Federal air quality rules, air quality operating permits or at the request of the Division.

h. Division-approved periods of research and development of emission control technologies provided that the unit does not exceed other applicable emission limits. For purposes of this subparagraph, the owner/operator shall submit a request for approval under this subparagraph at least 120 days prior to such date as well as including the following items: (1) length of time of research and development (R&D) period; (2) identification of steps to take to minimize emissions in accordance with best operational practices during R&D period; (3) for periods of R&D lasting more than 48 hours during any 5-day period, a demonstration that any increase in emissions resulting from the R&D project that are above that which is allowed by this subparagraph (uuu) will not cause or significantly contribute to an violation of any national ambient air quality standard or prevent compliance with any other applicable provisions.

State Only Enforceable

3.4.15 The Permittee shall not operate steam generating units SG01 or SG02 unless such source is equipped and operated with selective catalytic reduction and flue gas desulfurization, except the Permittee is not required to operate the required control technology under the following conditions:
[391-3-1-.02(2)(sss)]

a. Restarting an EGU when all Electric Utility Steam Generating Units are down and off-site power is not available (also known as a "Black Start").

b. Periods of startup of an EGU provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

c. Periods of shutdown of an EGU provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

d. Periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage of the respective EGU.

e. Periods of malfunction of EGU and/or control technology equipment provided that such periods are consistent with the requirements of paragraph 391-3-1-.02(2)(a)7.

f. Periods when the owner/operator is required to conduct the Relative Accuracy Test Audit and any other necessary periodic quality assurance procedures on the Continuous Emissions Monitoring System located on the bypass stack pursuant to 40 CFR Part 75 or the Georgia Department of Natural Resources Procedures for Testing and Monitoring Sources of Air Pollutants.

g. Periods when the owner/operator is required to conduct any performance tests on the bypass stack as required by state or federal air quality rules, air quality operating permits, or as ordered by the Division.

h. Division approved periods of research and development of emission control technologies provided that the unit does not exceed other applicable emission limits. For purposes of this subparagraph, the owner/operator shall submit a request for approval under this subparagraph at least 120 days prior to such date as well as including the following items: (1) length of time of research and development (R&D) period; (2) identification of steps to take to minimize emissions in accordance with best operational practices during R&D period; (3) for periods of R&D lasting more than 48 hours during any 5-day period, a demonstration that any increase in emissions resulting from the R&D project that are above that which is allowed by this subparagraph (sss) will not cause or significantly contribute to a violation of any national ambient air quality standard or prevent compliance with any other applicable provisions.

i. Any other occasion not covered by a. through h., as approved by the Division.

3.5 Equipment Standards Not Covered by a Federal or SIP Rule and Not Instituted as an Emission Cap or Operating Limit

None Applicable.

PART 4.0 REQUIREMENTS FOR TESTING

4.1 General Testing Requirements

4.1.1 The Permittee shall cause to be conducted a performance test at any specified emission unit when so directed by the Environmental Protection Division ("Division"). The test results shall be submitted to the Division within 60 days of the completion of the testing. Any tests shall be performed and conducted using methods and procedures that have been previously specified or approved by the Division.
[391-3-1-.02(6)(b)1(i)]

4.1.2 The Permittee shall provide the Division thirty (30) days (or sixty (60) days for tests required by 40 CFR Part 63) prior written notice of the date of any performance test(s) to afford the Division the opportunity to witness and/or audit the test.
[391-3-1-.02(3)(a) and 40 CFR 63.7(b)(1)]

4.1.3 Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. The methods for the determination of compliance with emission limits listed under Sections 3.2, 3.3, 3.4 and 3.5 are as follows:

a. Method 1 for the determination of sample point locations,

b. Method 2 for the determination of stack gas flow rate,

c. Method 3 or 3A for the determination of stack gas molecular weight,

d. Method 3A or 3B for the determination of the emissions rate correction factor or excess air,

e. Method 4 for the determination of stack gas moisture,

f. Method 5 or Method 17, as applicable, for the determination of Particulate Matter concentration,

g. Method 6 or 6C for the determination of Sulfur Dioxide concentration,

h. Method 7E for the determination of Nitrogen Oxide concentration for purposes other than verifying compliance with Georgia Rule 391-3-1-.02(2)(jjj),

i. Method 9 and the procedures contained in Section 1.3 of the above reference document for the determination of opacity,

j. Method 10 shall be used for the determination of Carbon Monoxide concentration.

k. Method 18 shall be used for the determination of Benzene, Toluene, Xylene, and Polyaromatic Hydrocarbon concentrations,

l. Method 19 when applicable, to convert Particulate Matter, Carbon Monoxide, Sulfur Dioxide, and Nitrogen Oxides concentrations (i.e. grains/dscf for PM, ppm for gaseous pollutants), as determined using other methods specified in this section, to emission rates (i.e. lb/MMBtu),

m. Method 20 for the determination of Nitrogen Oxides concentration from the combustion turbines with Emission Unit ID CT5A.

n. Method 25A shall be used to determine total Hydrocarbons and to calculate Volatile Organic Compound emissions.

o. ASTM Test Method D3431, D4629, or D3228 for the determination of the nitrogen content of fuel oil.

p. ASTM D129, D1552, D2622 or D4294 shall be used for the determination of fuel sulfur content.

q. ASTM D4057 for fuel oil sampling.

r. Method 0011 for the determination of formaldehyde and acetaldehyde concentrations from Test Methods of Evaluating Solid Waste, Physical/Chemical Methods, EPA publication, SW-846.

s. The procedures contained in Section 2.116.2 of the above-referenced document shall be used for the determination of nitrogen oxides concentration from the steam generating units with Emission Units ID Nos. SG01 and SG02 for purposes of verifying compliance with Georgia Rule 391-3-1-.02(2)(jjj).

t. The procedures contained in Section 2.125.4 of the above-referenced document shall be used for the determination of sulfur dioxide emission rates from steam generating units with emission units ID Nos. SG01 and SG02, located in the corresponding liner in the 675 ft stack for purposes of verifying compliance with Georgia Rule 391-3-1-.02(2)(uuu).

Minor changes in methodology may be specified or approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvement or corrections that, in his opinion, render those methods or procedures, or portions thereof, more reliable.
[391-3-1-.02(3)(a)]

4.1.4 **State Only Enforceable Condition**.
The Permittee shall provide, with the notification required under Condition 4.1.2, a test plan in accordance with Division guidelines.
[391-3-1-.02(3)(a)]

4.2 Specific Testing Requirements

4.2.1 The Permittee shall conduct the following performance tests on the following emissions units at the frequencies specified:

a. Particulate matter tests on Steam Generating Units 1 and 2 (Emission Unit IDs SG01 and SG02) scrubber bypass stacks (ST01 and ST02). The tests shall be conducted for each unit within 30 days following 8760 operating hours or 60 months for the unit, whichever comes first.
[391-3-1-.02(6)(b)1(i)]

b. Particulate matter tests on Steam Generating Units 1 and 2 (Emission Unit IDs SG01 and SG02) scrubber stacks (ST03 and ST04). The tests shall be conducted once every 60 months or as requested by the Division.
[391-3-1-.02(6)(b)1(i)]

4.2.2 The Permittee shall conduct the following performance test(s) on the following emissions units at the frequency specified:

a. A performance test for sulfur dioxide emissions on Steam Generating Units 1 and 2 (Emission Unit IDs SG01 and SG02), as specified below.

The performance test is based upon the 95 percent reduction required by Condition 3.4.13 The performance test is completed at the end of each boiler operating day after the initial performance test, which was completed for the first 30 successive boiler operating days following January 1, 2010, and a new 30-day percent reduction for Sulfur Dioxide (SO_2) is calculated to show compliance with Condition 3.4.13. Compliance with applicable SO_2 percent reduction requirements is determined based on the average inlet and outlet SO_2 emissions rates for the 30 successive boiler operating days. If the Permittee has not obtained the minimum quantity of emission data as required under Section 2.125.3(d) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**, compliance of the affected facility with the emission requirements required by Condition 3.4.13 for the day on which the 30-day period ends may be determined by the Director by following the applicable procedures in Section 12.7 of Method 19 of Appendix A of the **Procedures for Testing and Monitoring Sources of Air Pollutants**.
[391-3-1-.02(6)(b)1(i) and PTM Section 2.125]

PART 5.0 REQUIREMENTS FOR MONITORING (Related to Data Collection)

5.1 General Monitoring Requirements

5.1.1 Any continuous monitoring system required by the Division and installed by the Permittee shall be in continuous operation and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Monitoring system response, relating only to calibration checks and zero and span adjustments, shall be measured and recorded during such periods. Maintenance or repair shall be conducted in the most expedient manner to minimize the period during which the system is out of service.
[391-3-1-.02(6)(b)1]

5.2 Specific Monitoring Requirements

5.2.1 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated pollutants on the following equipment. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. A continuous opacity monitoring system (COMS) on Steam Generating Units 1 and 2 (Emission Unit IDs SG01 and SG02) located in each liner of the scrubber bypass stacks (ST01 and ST02).
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

b. A continuous emissions monitoring system (CEMS), for the measurement of nitrogen oxides concentration (ppm) and diluent concentrations (either Oxygen or Carbon Dioxide, percent), on each steam generating unit with Emission Unit IDs SG01 and SG02 located in each liner of the scrubber bypass stacks (ST01 and ST02) and in each liner of the scrubber stack (ST03 and ST04). The output of the CEMS shall be expressed in terms of pounds per million British thermal units (lb/MMBtu).

c. A continuous emissions monitoring system (CEMS), for the measurement of sulfur dioxide concentration (ppm) and diluent concentrations (either Oxygen or Carbon Dioxide, percent), on Steam Generating Units 1 and 2 (Emission Unit IDs SG01 and SG02). Sulfur dioxide emissions are monitored at both the inlet and outlet of each SO_2 control device. The output of the CEMS shall be expressed in terms of pounds per million British thermal units (lb/MMBtu).

5.2.2 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated parameters on the following equipment. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. A monitor system to monitor and record the fuel consumption and ratio of water to fuel being fired in Combustion Turbine Unit 5A (Emission Unit ID CT5A).
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

b. A continuous monitoring system for the measurement of the sparger tube liquid submergence level in the scrubber vessel (Control Device ID FGD1) for Unit 1 (Emission Unit ID SG01) and the scrubber vessel (Control Device ID FGD2) for Unit 2 (Emission Unit ID SG02).

State Only Enforceable Condition

5.2.3 The Permittee shall, upon written request by the Division, analyze any used oil to be burned in Steam Generating Units 1 or 2. The sample(s) shall be obtained and analyzed using the following methods;
[391-3-1-.02(6)(b)1(i)]

a. The procedures described in U.S. Environmental Protection Agency document EPA-600/2-80-018 (Samplers and Sampling Procedures for Hazardous Waste Streams) shall be used to obtain the sample.

b. Method 6010B, contained in the SW-846 methods manual of U.S. Environmental Protection Agency's Office of Solid Waste, shall be used to determine concentrations of arsenic, cadmium, chromium, and lead.

c. SW-846 Method 9077 C shall be used to determine total halogens.

d. ASTM D93 shall be used to determine flash point.

e. Polychlorinated Biphenyls (PCB) shall be determined using the test method described in U.S. Environmental Protection Agency Document EPA-600/4-81-045 (The Determination of Polychlorinated Biphenyls in Transformer Fluid and Waste Oil).

5.2.4 The Permittee shall monitor and record the nitrogen content of the fuel oil fired in Combustion Turbine Unit 5A using the procedures of 40 CFR 60.335(b)(9).
[40 CFR 60, Subpart GG]

Compliance Assurance Monitoring

5.2.5 The following pollutant specific emission unit(s) (PSEU) is/are subject to the Compliance Assurance Monitoring (CAM) Rule in 40 CFR 64.

Emission Unit	Pollutant
SG01	PM
SG02	PM
CT5A	NOx

Permit conditions in this permit for the PSEU(s) listed above with regulatory citation 40 CFR 70.6(a)(3)(i) are included for the purpose of complying with 40 CFR 64. In addition, the Permittee shall meet the requirements, as applicable, of 40 CFR 64.7, 64.8, and 64.9.
[40 CFR 64]

5.2.6 The Permittee shall comply with the performance criteria listed in the table below for the particulate matter emissions from steam generating unit SG01.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	**Indicator No. 1** **Opacity from SG01 exhaust scrubber bypass stack liner (ST01)**	**Indicator No. 2** **Jet Bubbling Reactor (JBR) Sparger Tube Liquid Submergence Level in FGD1 vessel for SG01**
Data Representativeness [64.3(b)(1)]	The continuous opacity monitoring system (COMS) is located in the SG01 exhaust scrubber bypass stack lines. The COMS was installed at a representative location in the stack per 40 CFR 60, Appendix B, PS-1.	The JBR sparger tube liquid submergence level is measured with a calibrated level indicator.
Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	Not Applicable.	Proper operation of the submergence level indicators is verified during initial startup. Alarms are installed to verify continuous proper operation.
QA/QC Practices and Criteria [64.3(b)(3)]	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.	The level indicators are calibrated per manufacturer's recommendations.
Monitoring Frequency [64.3(b)(4)]	The opacity is monitored continuously.	JBR sparger tube liquid submergence level is monitored continuously.
Data Collection Procedures [64.3(b)(4)]	The data acquisition system (DAS) retains all 6-minute opacity data.	The DAS retains all 3-hour average sparger tube liquid submergence level data.
Averaging Period [64.3(b)(4)]	The 6-minute opacity data is used to calculate 3-hour block averages.	The 1-minute data is used to calculate 3-hour block averages.

5.2.7 The Permittee shall comply with the performance criteria listed in the table below for the particulate matter emissions from steam generating unit SG02.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	**Indicator No. 1** **Opacity from SG02 exhaust scrubber bypass stack liner (ST02)**	**Indicator No. 2** **Jet Bubbling Reactor (JBR) Sparger Tube Liquid Submergence Level in FGD1 vessel for SG02**
Data Representativeness [64.3(b)(1)]	The continuous opacity monitoring system (COMS) is located in the SG02 exhaust scrubber bypass stack lines. The COMS was installed at a representative location in the stack per 40 CFR 60, Appendix B, PS-1.	The JBR sparger tube liquid submergence level is measured with a calibrated level indicator.
Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	Not Applicable.	Proper operation of the submergence level indicators is verified during initial startup. Alarms are installed to verify continuous proper operation.
QA/QC Practices and Criteria [64.3(b)(3)]	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.	The level indicators are calibrated per manufacturer's recommendations.
Monitoring Frequency [64.3(b)(4)]	The opacity is monitored continuously.	JBR sparger tube liquid submergence level is monitored continuously.
Data Collection Procedures [64.3(b)(4)]	The data acquisition system (DAS) retains all 6-minute opacity data.	The DAS retains all 3-hour average sparger tube liquid submergence level data.
Averaging Period [64.3(b)(4)]	The 6-minute opacity data is used to calculate 3-hour block averages.	The 1-minute data is used to calculate 3-hour block averages.

5.2.8 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxide emissions from combustion turbine CT5A.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	**Indicator No. 1 Water/fuel flow ratio**
A. Data Representativeness [64.3(b)(1)]	The fuel and water flow is monitored by the control system to calculate water/fuel flow ratio.
B. Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	Not Applicable.
C. QA/QC Practices and Criteria [64.3(b)(3)]	The fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	The fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The data acquisition system (DAS) retains all hourly average water/fuel flow ratio data.
Averaging Period [64.3(b)(4)]	The 1-minute data is used to calculate the 1-hour average.

5.2.9 The Permittee shall, at all times, maintain the monitoring required by Conditions 5.2.6, 5.2.7 and 5.2.8, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[40 CFR 64.7(b)]

5.2.10 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of CAM, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The Permittee shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[40 CFR 64.7(c)]

5.2.11 Upon detecting an excursion or exceedance as defined in Condition 6.1.7(b and c), the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable. Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.
[40 CFR 64.7(d)(1) and (2)]

5.2.12 If the Permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring in Conditions 5.2.6, 5.2.7 and 5.2.8 did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the part 70 or 71 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[40 CFR 64.7(e)]

Materials Handling System

5.2.13 Once each day or portion of each day of operation, the Permittee shall inspect affected emission points in the Material Handling System by conducting a walk-through of the facility and noting the occurrence of the following (a check list or other similar log may be used for this purpose):
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Any emissions unit which exhibits any visible emissions.

b. Any mechanical failure or malfunction that results in increased air emissions.

For each unit noted with visible emissions, mechanical problems, or malfunctions, the Permittee shall take corrective action with twelve (12) hours and reinspect the unit when it is operated next to verify that no visible emissions exist and that any mechanical problems or malfunctions have been corrected. The Permittee shall maintain a log of all corrective actions taken, including the dates and times of corrective actions taken and reinspections.

Georgia Rule (sss) and (uuu)

5.2.14 The CEMS required by Condition 5.2.1c shall be operated and data recorded during all periods of operation of the affected steam generating units with emission unit IDs SG01 and SG02 including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments and any period allowed under Georgia Rule 391-3-1-.02(2)(uuu)(4).
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

5.2.15 The Permittee shall obtain SO_2 emission data for at least 75 percent of all operating hours for each 30 successive boiler operating days. The 1-hour averages required under Section 1.4(h) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** are expressed in ng/J (lb/MMBTU) heat input and used to calculate the average emission rates under Georgia Rule 391-3-1-.02(2)(uuu). The 1-hour averages are calculated using the data points required under Section 1.4(h)(2) of the referenced document. If the minimum data requirement of this condition is not met, the Permittee may use the procedures of Section 2.125.3(f) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** to supplement the data collected.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

5.2.16 The Permittee is required to prepare and submit to the Division for approval a unit specific monitoring plan as required by Section 2.125.3(i) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** for the SO_2 CEMS required by Condition 5.2.1c, at least 45 days before commencing certification testing of the monitoring system. The Permittee shall comply with the requirements in the plan. The plan must address the following information:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device).

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

c. Performance evaluation procedures and acceptance criteria. (e.g., calibrations, relative accuracy test audits (RATA), etc.)

d. Operation and maintenance procedures in accordance with the general requirements of 40 CFR Part 75 or other acceptable procedures approved by the Division.

e. Ongoing recordkeeping and reporting procedures.

5.2.17 The SO_2, CO_2, and O_2 CEMS required by Condition 5.2.1 shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in Appendix B of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** or in according to the procedures in Appendices A and B to 40 CFR Part 75. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in Appendix F of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**. A data assessment report (DAR) shall be prepared according to Section 7 of Procedure 1 in Appendix F and shall be maintained on site and available for inspection or submittal to the Director. The Permittee may elect to implement alternative data accuracy procedures in Section 2.125.3(j) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

5.2.18 Except for periods of startup, shutdown, or malfunction, for each day or portion of a day that coal is burned in Steam Generating Units 1 and 2, the Permittee shall determine the daily average sulfur content (%S) of coal burned. A daily average shall be defined as an average of the hourly data for each unit for the day or portion of the day that coal is burned. For purposes of this Permit, the Permittee shall use the following equation to compute the hourly sulfur content (%S).
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

$$\%S = \left(\frac{E_{SO2} * 0.5}{CoalFlow * 0.95 * (1 - R)} \right) * 100$$

$$E_{SO2} = SO_2(lb / MMBtu) * HeatInput(MMbtu / hr)$$

$$HeatInput(MMbtu / hr) = Q * \left(\frac{1}{Fc} \right) * \left(\frac{\%CO_2}{100} \right) \text{(Eq. F-15 from 40 CFR 75)}$$

Where:

%S = coal sulfur content, percent by weight;

E_{SO2} = hourly SO_2 emissions at the FGD inlet (or in the bypass stack, if FGD is not in operation), lb/hr;

Q = Hourly average volumetric flow rate during unit operation, wet basis, scfh;

F_C = Carbon-based F-factor, listed in 40 CFR 75, App. F, Section 3.3.5 for each fuel, scf/MMBtu;

$\%CO_2$ = Hourly concentration of CO_2 during unit operation, percent CO_2 wet basis;

0.5 = Ratio of sulfur and sulfur dioxide molecular weights, dimensionless;

Coal flow = Hourly coal flow rate, lb/hr;

0.95 = Factor to account for sulfur to SO_2 conversion, dimensionless (from Table 1.1-3 in AP-42);

R = 0.011, Correction factor for conversion of SO_2 to SO_3 in SCR, dimensionless.

As an alternative to this equation, for each day or portion of a day that coal is burned in Steam Generating Units 1 and 2, the Permittee may obtain a sample of as-bunkered coal for analysis for sulfur content (%S). The sample shall be prepared using ASTM D2013 and analyzed using ASTM D4239.

State-Only Enforceable

5.2.19 Except from May 1 through September 30, the Permittee shall monitor and record the flue gas flow through SCR1 and SCR2 while each SCR is in operation. Flue gas flow through the SCR is defined as periods when the damper position is at least 90% open for more than 30 minutes per operating hour, excluding periods described in Georgia Rules for Air Quality Control 391-3-1-.02(2)(sss)20. From May 1 through September 30, the Permittee shall demonstrate compliance with the requirement in Georgia Rule 391-3-1-.02(2)(sss) to operate steam generating units SG01 and SG02 only when equipped with selective catalytic reduction through compliance with Georgia Rule 391-3-1-.02(2)(jjj), except during the periods that the Permittee is not required to operate selective catalytic reduction, as described in Georgia Rules for Air Quality Control 391-3-1-.02(2)(sss)20.
[391-3-1-.02(6)(b)1]

State-Only Enforceable

5.2.20 The Permittee shall demonstrate compliance with the requirement in Georgia Rule 391-3-1-.02(2)(sss) to operate steam generating units SG01 and SG02 only when equipped with flue gas desulfurization through compliance with Georgia Rule 391-3-1-.02(2)(uuu), except during the periods that the Permittee is not required to operate flue gas desulfurization, as described in Georgia Rules for Air Quality Control 391-3-1-.02(2)(sss)20.
[391-3-1-.02(6)(b)1]

PART 6.0 RECORD KEEPING AND REPORTING REQUIREMENTS

6.1 General Record Keeping and Reporting Requirements

6.1.1 Unless otherwise specified, all records required to be maintained by this Permit shall be recorded in a permanent form suitable for inspection and submission to the Division and to the EPA. The records shall be retained for at least five (5) years following the date of entry.
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)]

6.1.2 In addition to any other reporting requirements of this Permit, the Permittee shall report to the Division in writing, within seven (7) days, any deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning, or emissions control equipment for a period of four hours or more which results in excessive emissions.

The Permittee shall submit a written report that shall contain the probable cause of the deviation(s), duration of the deviation(s), and any corrective actions or preventive measures taken.
[391-3-1-.02(6)(b)1(iv), 391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(iii)(B)]

6.1.3 The Permittee shall submit written reports of any failure to meet an applicable emission limitation or standard contained in this permit and/or any failure to comply with or complete a work practice standard or requirement contained in this permit which are not otherwise reported in accordance with Conditions 6.1.4 or 6.1.2. Such failures shall be determined through observation, data from any monitoring protocol, or by any other monitoring which is required by this permit. The reports shall cover each semiannual period ending June 30 and December 31 of each year, shall be postmarked by August 29 and February 28, respectively following each reporting period, and shall contain the probable cause of the failure(s), duration of the failure(s), and any corrective actions or preventive measures taken.
[391-3-1-.03(10)(d)1.(i) and 40 CFR 70.6(a)(3)(iii)(B)]

6.1.4 The Permittee shall submit a written report containing any excess emissions, exceedances, and/or excursions as described in this permit and any monitor malfunctions for each quarterly period ending March 31, June 30, September 30, and December 31 of each year. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively following each reporting period. In the event that there have not been any excess emissions, exceedances, excursions or malfunctions during a reporting period, the report should so state. Otherwise, the contents of each report shall be as specified by the Division's Procedures for Testing and Monitoring Sources of Air Pollutants and shall contain the following:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(iii)(A)]

a. A summary report of excess emissions, exceedances and excursions, and monitor downtime, in accordance with Section 1.5(c) and (d) of the above referenced document, including any failure to follow required work practice procedures.

b. Total process operating time during each reporting period.

c. The magnitude of all excess emissions, exceedances and excursions computed in accordance with the applicable definitions as determined by the Director, and any conversion factors used, and the date and time of the commencement and completion of each time period of occurrence.

d. Specific identification of each period of such excess emissions, exceedances, and excursions that occur during startups, shutdowns, or malfunctions of the affected facility. Include the nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

e. The date and time identifying each period during which any required monitoring system or device was inoperative (including periods of malfunction) except for zero and span checks, and the nature of the repairs, adjustments, or replacement. When the monitoring system or device has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

f. Certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

6.1.5 Where applicable, the Permittee shall keep the following records:
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(ii)(A)]

a. The date, place, and time of sampling or measurement;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of such analyses; and

f. The operating conditions as existing at the time of sampling or measurement.

6.1.6 The Permittee shall maintain files of all required measurements, including continuous monitoring systems, monitoring devices, and performance testing measurements; all continuous monitoring system or monitoring device calibration checks; and adjustments and maintenance performed on these systems or devices. These files shall be kept in a permanent form suitable for inspection and shall be maintained for a period of at least five (5) years following the date of such measurements, reports, maintenance and records.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6 (a)(3)(ii)(B)]

6.1.7 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Excess emissions: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping which is specifically defined, or stated to be, excess emissions by an applicable requirement)

i. Excess emissions of nitrogen oxides as described in Condition 6.2.13

ii. Any unit operating one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system installed on Combustion Turbine Unit 5A, falls below the water-to-fuel ratio determined during the initial performance test that demonstrated compliance with the nitrogen oxides limit in Condition 3.3.2.

-AND-

Any unit operating hour in which no water or steam is injected.
[40 CFR 70.6(a)(3)(iii)(A)]

b. Exceedances: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the results of the monitoring)

i. Any six-minute period during which the average opacity, as measured by the COMS for Steam Generating Units 1 or 2 (Emission Unit IDs SG01 or SG02), exceeds 40 percent shall be reported as an exceedance.
[40 CFR 70.6(a)(3)(iii)(A)]

ii. An ozone season (defined as May 1 through September 30) total NOx emission which exceeds 32,335.8 tons from the applicable equipment specified in Condition 3.2.6.

iii. Any period during which the sulfur content of the fuel oil fired in Combustion Turbine 5A exceeds 0.5 percent.
[40 CFR 70.6(a)(3)(iii)(A)]

iv. Any time fuel fired in any steam generating unit (Emission Unit IDs SG01 and SG02) has a sulfur content which exceeds 3.0 percent sulfur, by weight.

v. Any time coal-derived synthetic fuel fired in any steam generating unit (Emission Unit IDs SG01 and SG02) does not meet the specifications of Condition 3.2.1e.

vi. Any 30 day rolling average SO_2 percent reduction that is calculated in accordance with the procedures of Condition 6.2.16 that is less than 95% for SG01 and SG02.

c. Excursions: (means for the purpose of this Condition and Condition 6.1.4, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring)

i. For Source 1, comprised of Steam Generating Unit 1 (Emission Unit ID SG01), any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 40 percent shall be reported. A three-hour block average shall be defined as any one of the eight consecutive three-hour time periods between 12:00 midnight and the following midnight.
[40 CFR 70.6(a)(3)(iii)(A)]

ii. For Source 2, comprised of Steam Generating Unit 2 (Emission Unit ID SG02), any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 40 percent shall be reported. A three-hour block average shall be defined as any one of the eight consecutive three-hour time periods between 12:00 midnight and the following midnight.
[40 CFR 70.6(a)(3)(iii)(A)]

iii. For sources specified in Condition 5.2.13, any required daily inspection during which any emissions unit which exhibits any visible emissions that is not corrected within 12 hours of the observation.

iv. For Control Device ID FGD1, any three-hour block average when the sparger tube liquid submergence level in the scrubber vessel is less than 5.0 inches, as measured by the CMS. A three-hour block average shall be defined as any one of the eight consecutive three-hour periods between 12:00 midnight and the following midnight.

v. For Control Device ID FGD2, any three-hour block average when the sparger tube liquid submergence level in the scrubber vessel is less than 5.0 inches, as measured by the CMS. A three-hour block average shall be defined as any one of the eight consecutive three-hour periods between 12:00 midnight and the following midnight.

State-Only Enforceable

vi. Except from May 1 through September 30, any 30 consecutive operating day period in which the flue gas did not go through the SCR for at least 90% of the operating hours during that period, excluding periods described in Georgia Rules for Air Quality Control 391-3-1-.02(2)(sss)20.

6.2 Specific Record Keeping and Reporting Requirements

State Only Enforceable Condition.

6.2.1 The Permittee shall retain monthly records of all fuel burned (except c, d, and f below which shall be monitored on an as received basis) in the steam generating units with Emission Unit IDs SG01 and SG02. The records shall be available for inspection or submittal to the Division, upon request, and contain the following:
[391-3-1-.02(6)(b)1(i)]

a. Quantity (tons) of coal burned.

b. Aggregate quantity (gallons) of distillate oil, No. 2 fuel oil, biodiesel, biodiesel blends, or very low sulfur oil burned.

c. Quantity (tons) of sawdust received.

d. Quantity (tons) of biomass received.

e. Quantity (gallons) of used oil burned.

f. Quantity (tons) of coal – derived synthetic fuel received.

State Only Enforceable Condition.

6.2.2 The Permittee shall maintain records of representative samples of the coal and sawdust burned in the steam generating units with Emission Unit IDs SG01 and SG02. The records shall be available for inspection or submittal to the Division, upon request, and contain the following:
[391-3-1-.02(6)(b)1(i)]

a. Percent ash content of coal.

b. Heat content (Btu per pound) of sawdust.

6.2.3 The Permittee shall verify that each shipment of fuel oil for combustion in Steam Generating Units 1 and 2 (Emission Unit IDs SG01 and SG02), Start-up Boiler Units 1 and 2 (Emission Unit IDs SB01 and SB02), and Combustion Turbine Unit 5A (Emission Unit ID CT5A) complies with the specifications for fuel oil as defined in ASTM D396, ASTM D975, or ASTM D6751 by obtaining fuel oil supplier certifications. Supplier certifications shall contain the name of the supplier and a statement from the supplier that the oil complies with the specifications for fuel oil as defined in ASTM D396, ASTM D975, or ASTM D6751. As an alternative to the procedure described above, the Permittee may, for each shipment of fuel oil received, obtain a sample for analysis of the sulfur content. The procedures of ASTM D4057 shall be used to acquire the sample. Sulfur content shall be determined using the procedures of Test Method ASTM D129 or D1552 or by some other test method approved by the US EPA and acceptable to the Division.
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]

6.2.4 The Permittee shall maintain a record of all actions taken in accordance with Condition 3.4.5 to suppress fugitive dust from the coal handling system (CHS) and the ash handling system (AHS). Such records shall include the date and time of occurrence and a description of the actions taken.
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]

6.2.5 For each shipment of coal-derived synthetic fuel received, the Permittee shall obtain from the supplier a statement certifying that each shipment of synthetic fuel to be received complies with the specification as described in Condition 3.2.1e.
[391-3-1-.02(6)(b)1(i)]

Combustion Turbine CT5A

6.2.6 The Permittee shall retain monthly records of all fuel burned in Combustion Turbine Unit 5A (Emission Unit ID CT5A). The records shall be available for inspection or submittal to the Division, upon request, and contain the quantity (gallons) of distillate oil, No. 2 fuel oil, biodiesel, biodiesel blends, or very low sulfur oil burned and the hours of operation of the turbine.
[391-3-1-.02(6)(b)1(i) and 40 CFR 60.334(a)]

6.2.7 The Permittee shall maintain records specifying the hours per month of operation of the combustion turbine (Emission Unit ID No. CT5A). In addition, these records should include documentation of the purpose of turbine operation (i.e., routine testing, maintenance, etc). This condition applies May 1 through September 30 of each year. These records shall be in a format suitable and available for inspection or submittal.
[391-3-1-.02(6)(b)(1) and 40 CFR 70.6(a)(3)(i)]

6.2.8 The Permittee shall record any time that combustion turbine with Emission Unit ID No. CT5A is operated during the ozone season (May 1 through September 30) of each year. The record(s) of CT5A turbine operation required by this condition shall be maintained in accordance with Condition 6.1.1 and shall be submitted with the report required by Condition 6.1.4. For each calendar month in the ozone season during which CT5A turbine is not operated, the report required by Condition 6.1.4 shall state such.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

Record Keeping Requirements for the Ozone Season NOx Emission Caps

6.2.9 The Permittee shall use the data obtained from the NOx CEMS to compute the monthly mass emission rate, in tons per calendar month, of NOx from the following coal-fired steam generating units on a combined basis: Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Bowen (AFS No. 015-00011); Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Branch (AFS No. 237-00008); Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Hammond (AFS No. 115-00003); Emission Unit IDs SGM1 and SGM2 at Plant McDonough (AFS No. 067-00003); Emission Unit IDs SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008); Emission Unit IDs SG01 and SG02 at Plant Wansley (AFS No. 149-00001); Emission Unit IDs SG01, SG02, SG03, SG04, SG05, SG06, and SG07 at Plant Yates (AFS No. 077-00001). This emission rate must include emissions from startup, shutdown, and malfunction. This condition only applies during the ozone season (May 1 to September 30).
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.10 The Permittee shall use the records required by Condition 6.2.9 to determine the ozone season total emission rate, in tons, of NOx from the following coal-fired steam generating units on a combined basis: Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Bowen (AFS No. 015-00011); Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Branch (AFS No. 237-00008); Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Hammond (AFS No. 115-00003); Emission Unit IDs SGM1 and SGM2 at Plant McDonough (AFS No. 067-00003); Emission Unit IDs SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008); Emission Unit IDs SG01 and SG02 at Plant Wansley (AFS No. 149-00001); Emission Unit IDs SG01, SG02, SG03, SG04, SG05, SG06, and SG07 at Plant Yates (AFS No. 077-00001). This emission rate must include emissions from startup, shutdown, and malfunction. This condition only applies during the ozone season (May 1 to September 30).
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

Record Keeping for the Verification of Georgia Rule (jjj) NOx Emission Limits

6.2.11 The Permittee shall determine compliance with the NOx emissions limitations in Condition Nos. 3.4.7, 3.4.8, 3.4.9, and 3.4.10 using emissions data acquired by the NOx CEMS. The 30-day rolling average shall be determined as follows:
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]

a. The first 30-day averaging period shall begin on the first operating day of the ozone season.

b. The 30-day average shall be the average of all valid hours of NOx emissions data for any 30 successive operating days during the period of the ozone season.

c. The last 30-day averaging period shall end on the last operating day of the ozone season.

d. After the first 30-day average, a new 30-day rolling average shall be calculated after each operating day.

e. For the purpose of this Permit, an operating day is a 24 hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period.

6.2.12 Following the date on which the NOx emission limitation in Condition Nos. 3.4.7 and 3.4.8 become applicable and during the period of applicability, the Permittee shall determine compliance with the limitation using the procedures of Section 2.116.2 of the Division's ***Procedures for Testing and Monitoring Sources of Air Pollutants***. The Permittee shall maintain the records specified in Section 2.116.4 of the aforementioned procedures document and use these records to prepare a quarterly report. Reportable emissions are any calculated 30-day rolling average NOx emissions rate which exceeds the limit established in Condition Nos. 3.4.7 and 3.4.8 whichever is applicable. Excess emissions are those that exceed an area-wide average limit in Condition Nos. 3.4.9 or 3.4.10 as well as the source's respective Alternative Emission Limitation as specified in Condition Nos. 3.4.7 and 3.4.8.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.13 The Permittee shall submit written reports to the Division of reportable emissions under Condition 6.2.12 (excess emissions would be reported per Condition 6.1.7) for each calendar quarter ending June 30 (April excluded) and September 30. All reports shall be postmarked by August 29 and November 29, respectively following each reporting period. In the event that there have not been any reportable emissions during a reporting period, the report should state as such.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.14 The Permittee may submit, via electronic media, any report required by Part 6.0 of this permit provided such format has been approved by the Division.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

Recordkeeping for the Verification of Georgia Rule (uuu) SO_2 Emission Limits

6.2.15 The Permittee shall determine compliance with the SO_2 emissions limitations in Condition No. 3.4.13 based on the average emission rate for 30 successive boiler operating days. [391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. The percent of potential SO_2 emissions ($\%P_s$) to the atmosphere shall be computed using the following equation:

$$\%P_s = \frac{(100 - \%R_f)(100 - \%R_g)}{100}$$

Where:
$\%P_s$ = Percent of potential SO_2 emissions, percent;
$\%R_f$ = Percent reduction from fuel pretreatment, percent; and
$\%R_g$ = Percent reduction by SO_2 control system, percent.

b. The procedures of Method 19 may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

c. The procedures in Method 19 shall be used to determine the percent SO_2 reduction ($\%R_g$) of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

6.2.16 The Permittee shall determine compliance with the limitation in Condition 3.4.13, using the procedures of Section 2.125.4 of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**. The Permittee shall maintain the records specified in Section 2.125.5 of the aforementioned document and the records used to prepare a quarterly report. Reportable emissions are any calculated 30-day rolling average SO_2 emissions reduction which exceeds the limit established in Condition No. 3.4.13. The following information shall be maintained for each 24-hour reporting period:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Calendar date.

b. Percent reduction of the potential combustion concentration of SO_2 for each 30 successive boiler operating days; reasons for non-compliance with the emissions standards; and description of corrective actions taken.

c. Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

d. Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or other reasons, and justification for excluding data for reasons other than startup or shutdown conditions.

e. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

f. Identification of times when hourly averages have been obtained based on manual sampling methods.

g. Identification of the times when the pollutant concentration exceeded full span of the CEMS.

h. Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

i. Results of any daily calibration error tests or quarterly accuracy assessment as required under Section 2.125.3(j) of the aforementioned document that does not meet the applicable accuracy specification and the subsequent acceptable daily calibration error test or quarterly accuracy assessment.

6.2.17 The Permittee shall submit written reports to the Division of reportable emissions under Condition 6.2.17 (excess emissions would be reported per Condition 6.1.7) for each calendar quarter. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively following each reporting period. In the event that there have not been any reportable emissions during a reporting period, the report should state as such. The Permittee shall determine compliance with the limitation using the procedures of Section 2.125.4 of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**. The Permittee shall maintain the records specified in Section 2.125.5 of the aforementioned procedures document and use these records to prepare a quarterly report. Reportable emissions are any calculated 30-day rolling average SO_2 emissions rate which exceeds the limit established in Condition No. 3.4.13.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.18 In the event the minimum quantity of emissions data as required by Section 2.125.4 of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of Section 2.125.2(d) of the aforementioned document is reported to the Division for that 30-day period.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i), as applicable.

b. The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i), as applicable.

c. The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*), as applicable.

d. The applicable potential combustion concentration.

e. The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}), as applicable.

6.2.19 For any periods for which SO_2 emissions data are not available, the Permittee shall submit a signed statement to the Division indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability. Within the signed statement, the Permittee must include:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Verification of whether the required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this text and is representative of plant performance.

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

d. Compliance with the standards has or has not been achieved during the reporting period.

6.2.20 The Permittee shall submit results of each RATA required under Section 2.125.3(j) of the Division's **Procedures of Monitoring and Testing of Air Pollutants** within 60 days of the completion of RATA.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

PART 7.0 OTHER SPECIFIC REQUIREMENTS

7.1 Operational Flexibility

7.1.1 The Permittee may make Section 502(b)(10) changes as defined in 40 CFR 70.2 without requiring a Permit revision, if the changes are not modifications under any provisions of Title I of the Federal Act and the changes do not exceed the emissions allowable under the Permit (whether expressed therein as a rate of emissions or in terms of total emissions). For each such change, the Permittee shall provide the Division and the EPA with written notification as required below in advance of the proposed changes and shall obtain any Permits required under Rules 391-3-1-.03(1) and (2). The Permittee and the Division shall attach each such notice to their copy of this Permit.
[391-3-1-.03(10)(b)5 and 40 CFR 70.4(b)(12)(i)]

a. For each such change, the Permittee's written notification and application for a construction Permit shall be submitted well in advance of any critical date (typically at least 3 months in advance of any commencement of construction, Permit issuance date, etc.) involved in the change, but no less than seven (7) days in advance of such change and shall include a brief description of the change within the Permitted facility, the date on which the change is proposed to occur, any change in emissions, and any Permit term or condition that is no longer applicable as a result of the change.

b. The Permit shield described in Condition 8.16.1 shall not apply to any change made pursuant to this condition.

7.2 Off-Permit Changes

7.2.1 The Permittee may make changes that are not addressed or prohibited by this Permit, other than those described in Condition 7.2.2 below, without a Permit revision, provided the following requirements are met:
[391-3-1-.03(10)(b)6 and 40 CFR 70.4(b)(14)]

a. Each such change shall meet all applicable requirements and shall not violate any existing Permit term or condition.

b. The Permittee must provide contemporaneous written notice to the Division and to the EPA of each such change, except for changes that qualify as insignificant under Rule 391-3-1-.03(10)(g). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the Permit shield in Condition 8.16.1.

d. The Permittee shall keep a record describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the Permit, and the emissions resulting from those changes.

7.2.2 The Permittee shall not make, without a Permit revision, any changes that are not addressed or prohibited by this Permit, if such changes are subject to any requirements under Title IV of the Federal Act or are modifications under any provision of Title I of the Federal Act. [Rule 391-3-1-.03(10)(b)7 and 40 CFR 70.4(b)(15)]

7.3 Alternative Requirements
[White Paper #2]

Not Applicable

7.4 Insignificant Activities
(see Attachment B for the list of Insignificant Activities in existence at the facility at the time of permit issuance)

7.5 Temporary Sources
[391-3-1-.03(10)(d)5 and 40 CFR 70.6(e)]

Not Applicable

7.6 Short-term Activities
(see Form D5 "Short Term Activities" of the Permit application and White Paper #1)

7.6.1 The Permittee shall maintain records of the duration and frequency of the following Short-term Activities:
[391-3-1-.02(2)(a)1]

a. Sand blasting for maintenance purposes.

b. Asbestos removal in accordance with Georgia Rule 391-3-1-.02(9)(b)7.

7.7 Compliance Schedule/Progress Reports
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(4)]

None applicable.

7.8 Emissions Trading
[391-3-1-.03(10)(d)1(ii) and 40 CFR 70.6(a)(10)]

Not Applicable

7.9 Acid Rain Requirements

Facility ORIS code: 6052
Effective: January 1, 2013 through December 31, 2017

7.9.1 Emissions which exceed any allowances that the Permittee lawfully holds under Title IV of the 1990 CAAA, or the regulations promulgated thereunder, are expressly prohibited.
[40 CFR 70.6(a)(4)]

7.9.2 Permit revisions are not required for increases in emissions that are authorized by allowances acquired pursuant to the State's Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.
[40 CFR 70.6(a)(4)(i)]

7.9.3 This permit does not place limits on the number of allowances the Permittee may hold. However, the Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.
[40 CFR 70.6(a)(4)(ii)]

7.9.4 Any allowances held by the Permittee shall be accounted for according to the procedures established in regulations promulgated under Title IV of the 1990 CAAA.
[40 CFR 70.6(a)(4)(iii)]

7.9.5 Each affected unit, with the exceptions specified in 40 CFR 72.9(g)(6), operated in accordance with the Acid Rain portion of this permit shall be deemed to be operating in compliance with the Acid Rain Program.
[40 CFR 70.6(f)(3)(iii)]

7.9.6 Where an applicable requirement is more stringent than an applicable requirement of regulations promulgated under Title IV of the 1990 CAAA, both provisions shall be incorporated into the permit and shall be enforceable.
[40 CFR 70.6(a)(1)(ii)]

7.9.7 SO_2 Allowance Allocations and NO_X Requirements for each affected unit [40 CFR 73 (SO_2) and 40 CFR 76 (NO_X)]

EMISSION UNIT ID	EPA ID		2013	2014	2015	2016	2017
		SO_2 Allowances	30567	30567	30567	30567	30567
SG01	1	NO_X Limit	The standard annual average NOx limit for a Phase I tangentially fired boiler is 0.45 lb/mmBtu. In lieu of this limit, the Permittee may comply with 40 CFR Part 76 by complying with an approved Phase II NOx averaging plan as described below.				

Pursuant to 40 CFR 76.11, Georgia EPD approves five NOx emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2013, 2014, 2015, 2016, and 2017. Under each plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.41 lb/mmBtu**. In addition, this unit shall not have an annual heat input less than **63,896,521 mmBtu**.

Under the plan, the actual Btu-weighted annual average NOx emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Mississippi Department of Environmental Quality, the Alabama Department of Environmental Management, the Florida Department of Environmental Protection, and the Jefferson County Department of Health (Alabama) have also approved this averaging plan.

In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.

<table>
<tr><td></td><td></td><td></td><td>2013</td><td>2014</td><td>2015</td><td>2016</td><td>2017</td></tr>
<tr><td rowspan="2">EMISSION UNIT ID

SG02</td><td rowspan="2">EPA ID

2</td><td>SO_2 Allowances</td><td>28259</td><td>28259</td><td>28259</td><td>28259</td><td>28259</td></tr>
<tr><td>NO_X Limit</td><td colspan="5">The standard annual average NOx limit for a Phase I tangentially fired boiler is 0.45 lb/mmBtu. In lieu of this limit, the Permittee may comply with 40 CFR Part 76 by complying with an approved Phase II NOx averaging plan as described below.</td></tr>
<tr><td colspan="8">Pursuant to 40 CFR 76.11, Georgia EPD approves five NOx emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2013, 2014, 2015, 2016, and 2017. Under each plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.42 lb/mmBtu. In addition, this unit shall not have an annual heat input less than 56,607,431 mmBtu.

Under the plan, the actual Btu-weighted annual average NOx emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Mississippi Department of Environmental Quality, the Alabama Department of Environmental Management, the Florida Department of Environmental Protection, and the Jefferson County Department of Health (Alabama) have also approved this averaging plan.

In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.</td></tr>
</table>

Note: The number of allowances allocated to Phase II affected units by U.S. EPA may change as a result of revisions to 40 CFR Part 73. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See CFR 72.84).

7.9.8 Permit Application: The Phase II Acid Rain Permit Application, Compliance Plan, and NOx Averaging Plan submitted for this source, as corrected by the State of Georgia, is attached as part of this Permit. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.
[40 CFR 72.50(a)(1)]

7.10 Prevention of Accidental Releases (Section 112(r) of the 1990 CAAA)
[391-3-1-.02(10)]

7.10.1 When and if the requirements of 40 CFR Part 68 become applicable, the Permittee shall comply with all applicable requirements of 40 CFR Part 68, including the following.

a. The Permittee shall submit a Risk Management Plan (RMP) as provided in 40 CFR 68.150 through 68.185. The RMP shall include a registration that reflects all covered processes.

b. For processes eligible for Program 1, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a. and the following additional requirements:

i. Analyze the worst-case release scenario for the process(es), as provided in 40 CFR 68.25; document that the nearest public receptor is beyond the distance to a toxic or flammable endpoint defined in 40 CFR 68.22(a); and submit in the RMP the worst-case release scenario as provided in 40 CFR 68.165.
ii. Complete the five-year accident history for the process as provided in 40 CFR 68.42 and submit in the RMP as provided in 40 CFR 68.168
iii. Ensure that response actions have been coordinated with local emergency planning and response agencies
iv. Include a certification in the RMP as specified in 40 CFR 68.12(b)(4)

c. For processes subject to Program 2, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a., 7.10.1.b. and the following additional requirements:

i. Develop and implement a management system as provided in 40 CFR 68.15
ii. Conduct a hazard assessment as provided in 40 CFR 68.20 through 68.42
iii. Implement the Program 2 prevention steps provided in 40 CFR 68.48 through 68.60 or implement the Program 3 prevention steps provided in 40 CFR 68.65 through 68.87
iv. Develop and implement an emergency response program as provided in 40 CFR 68.90 through 68.95
v. Submit as part of the RMP the data on prevention program elements for Program 2 processes as provided in 40 CFR 68.170

d. For processes subject to Program 3, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a., 7.10.1.b. and the following additional requirements:

i. Develop and implement a management system as provided in 40 CFR 68.15
ii. Conduct a hazard assessment as provided in 40 CFR 68.20 through 68.42
iii. Implement the prevention requirements of 40 CFR 68.65 through 68.87
iv. Develop and implement an emergency response program as provided in 40 CFR 68.90 through 68.95
v. Submit as part of the RMP the data on prevention program elements for Program 3 as provided in 40 CFR 68.175

e. All reports and notification required by 40 CFR Part 68 must be submitted electronically using RMP*eSubmit (information for establishing an account can be found at www.epa.gov/emergencies/content/rmp/rmp_esubmit.htm). Electronic Signature Agreements should be mailed to:

MAIL

Risk Management Program (RMP) Reporting Center
P.O. Box 10162
Fairfax, VA 22038

COURIER & FEDEX

Risk Management Program (RMP) Reporting Center
CGI Federal
12601 Fair Lakes Circle
Fairfax, VA 22033

Compliance with all requirements of this condition, including the registration and submission of the RMP, shall be included as part of the compliance certification submitted in accordance with Condition 8.14.1.

7.11 Stratospheric Ozone Protection Requirements (Title VI of the CAAA of 1990)

7.11.1 If the Permittee performs any of the activities described below or as otherwise defined in 40 CFR Part 82, the Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliance must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to 40 CFR 82.166.
[Note: "MVAC-like appliance" is defined in 40 CFR 82.152.]

e. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to 40 CFR 82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

7.11.2 If the Permittee performs a service on motor (fleet) vehicles and if this service involves an ozone-depleting substance (refrigerant) in the MVAC, the Permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include air-tight sealed refrigeration systems used for refrigerated cargo, or air conditioning systems on passenger buses using HCFC-22 refrigerant.

7.12 Revocation of Existing Permits and Amendments

The following Air Quality Permits, Amendments, and 502(b)10 are subsumed by this permit and are hereby revoked:

Air Quality Permit and Amendment Number(s)	Dates of Original Permit or Amendment Issuance
4911-149-0001-V-02-0	Issued: December 20, 2006 Effective: January 1, 2007
4911-149-0001-V-02-1	March 7, 2007
4911-149-0001-V-02-2	August 21, 2007
4911-149-0001-V-02-3	October 30, 2008
4911-149-0001-V-02-4	November 25, 2008
4911-149-0001-V-02-5	March 12, 2009
4911-149-0001-V-02-6	September 17, 2009
4911-149-0001-V-02-7	November 18, 2009
4911-149-0001-V-02-8	November 30, 2010
4911-149-0001-V-02-9	March 14, 2012

7.13 Pollution Prevention

None applicable

7.14 Specific Conditions

None applicable

7.15 Clean Air Interstate Rule (CAIR) Requirements
[40 CFR 96, 391-3-1-.02(12), 391-3-1-.02(13)]

7.15.1 Permit Application: The CAIR Permit Application, as corrected by the State of Georgia, is attached as part of this Permit. The owners and operators of these CAIR units as identified in Condition 7.15.2 must comply with the standard requirements and special provisions set forth in the application.
[40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, and 96.322]

7.15.2 The owners and operators of the source shall comply with the Annual NO_X Allowance Allocations in accordance with the CAIR requirements as follows:
[40 CFR 96, 391-3-1-.02(12)]

	Emission Unit IDs.	EPA IDs.		2012	2013
Facility Wide	SG01 SG02 CT5A CT6A/DB6A* CT6B/DB6B* CT7A/DB7A* CT7B/DB7B*	1 2 CT5A CT6A/DB6A CT6B/DB6B CT7A/DB7A CT7B/DB7B	CAIR Facility Wide Annual NO_X Allowances (tpy)	8952	8952

* Part of Title V Permit 4911-149-0011-V-01-0

PART 8.0 GENERAL PROVISIONS

8.1 Terms and References

8.1.1 Terms not otherwise defined in the Permit shall have the meaning assigned to such terms in the referenced regulation.

8.1.2 Where more than one condition in this Permit applies to an emission unit and/or the entire facility, each condition shall apply and the most stringent condition shall take precedence.
[391-3-1-.02(2)(a)2]

8.2 EPA Authorities

8.2.1 Except as identified as "State-only enforceable" requirements in this Permit, all terms and conditions contained herein shall be enforceable by the EPA and citizens under the Clean Air Act, as amended, 42 U.S.C. 7401, et seq.
[40 CFR 70.6(b)(1)]

8.2.2 Nothing in this Permit shall alter or affect the authority of the EPA to obtain information pursuant to 42 U.S.C. 7414, "Inspections, Monitoring, and Entry."
[40 CFR 70.6(f)(3)(iv)]

8.2.3 Nothing in this Permit shall alter or affect the authority of the EPA to impose emergency orders pursuant to 42 U.S.C. 7603, "Emergency Powers."
[40 CFR 70.6(f)(3)(i)]

8.3 Duty to Comply

8.3.1 The Permittee shall comply with all conditions of this operating Permit. Any Permit noncompliance constitutes a violation of the Federal Clean Air Act and the Georgia Air Quality Act and/or State rules and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a Permit renewal application. Any noncompliance with a Permit condition specifically designated as enforceable only by the State constitutes a violation of the Georgia Air Quality Act and/or State rules only and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a Permit renewal application.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(i)]

8.3.2 The Permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the Permitted activity in order to maintain compliance with the conditions of this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(ii)]

8.3.3 Nothing in this Permit shall alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of Permit issuance.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(f)(3)(ii)]

8.3.4 Issuance of this Permit does not relieve the Permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Director or any other federal, state, or local agency.
[391-3-1-.03(10)(e)1(iv) and 40 CFR 70.7(a)(6)]

8.4 Fee Assessment and Payment

8.4.1 The Permittee shall calculate and pay an annual Permit fee to the Division. The amount of fee shall be determined each year in accordance with the "Procedures for Calculating Air Permit Fees."
[391-3-1-.03(9)]

8.5 Permit Renewal and Expiration

8.5.1 This Permit shall remain in effect for five (5) years from the effective date. The Permit shall become null and void after the expiration date unless a timely and complete renewal application has been submitted to the Division at least six (6) months, but no more than eighteen (18) months prior to the expiration date of the Permit.
[391-3-1-.03(10)(d)1(i), (e)2, and (e)3(ii) and 40 CFR 70.5(a)(1)(iii)]

8.5.2 Permits being renewed are subject to the same procedural requirements, including those for public participation and affected State and EPA review, that apply to initial Permit issuance.
[391-3-1-.03(10)(e)3(i)]

8.5.3 Notwithstanding the provisions in 8.5.1 above, if the Division has received a timely and complete application for renewal, deemed it administratively complete, and failed to reissue the Permit for reasons other than cause, authorization to operate shall continue beyond the expiration date to the point of Permit modification, reissuance, or revocation.
[391-3-1-.03(10)(e)3(iii)]

8.6 Transfer of Ownership or Operation

8.6.1 This Permit is not transferable by the Permittee. Future owners and operators shall obtain a new Permit from the Director. The new Permit may be processed as an administrative amendment if no other change in this Permit is necessary, and provided that a written agreement containing a specific date for transfer of Permit responsibility coverage and liability between the current and new Permittee has been submitted to the Division at least thirty (30) days in advance of the transfer.
[391-3-1-.03(4)]

8.7 Property Rights

8.7.1 This Permit shall not convey property rights of any sort, or any exclusive privileges.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(iv)]

8.8 Submissions

8.8.1 Reports, test data, monitoring data, notifications, annual certifications, and requests for revision and renewal shall be submitted to:

Georgia Department of Natural Resources
Environmental Protection Division
Air Protection Branch
Atlanta Tradeport, Suite 120
4244 International Parkway
Atlanta, Georgia 30354-3908

8.8.2 Any records, compliance certifications, and monitoring data required by the provisions in this Permit to be submitted to the EPA shall be sent to:

Air and EPCRA Enforcement Branch – U. S. EPA Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303-3104

8.8.3 Any application form, report, or compliance certification submitted pursuant to this Permit shall contain a certification by a responsible official of its truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
[391-3-1-.03(10)(c)2, 40 CFR 70.5(d) and 40 CFR 70.6(c)(1)]

8.8.4 Unless otherwise specified, all submissions under this permit shall be submitted to the Division only.

8.9 Duty to Provide Information

8.9.1 The Permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the Permit application, shall promptly submit such supplementary facts or corrected information to the Division.
[391-3-1-.03(10)(c)5]

8.9.2 The Permittee shall furnish to the Division, in writing, information that the Division may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit. Upon request, the Permittee shall also furnish to the Division copies of records that the Permittee is required to keep by this Permit or, for information claimed to be confidential, the Permittee may furnish such records directly to the EPA, if necessary, along with a claim of confidentiality.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(v)]

8.10 Modifications

8.10.1 Prior to any source commencing a modification as defined in 391-3-1-.01(pp) that may result in air pollution and not exempted by 391-3-1-.03(6), the Permittee shall submit a Permit application to the Division. The application shall be submitted sufficiently in advance of any critical date involved to allow adequate time for review, discussion, or revision of plans, if necessary. Such application shall include, but not be limited to, information describing the precise nature of the change, modifications to any emission control system, production capacity of the plant before and after the change, and the anticipated completion date of the change. The application shall be in the form of a Georgia air quality Permit application to construct or modify (otherwise known as a SIP application) and shall be submitted on forms supplied by the Division, unless otherwise notified by the Division.
[391-3-1-.03(1) through (8)]

8.11 Permit Revision, Revocation, Reopening and Termination

8.11.1 This Permit may be revised, revoked, reopened and reissued, or terminated for cause by the Director. The Permit will be reopened for cause and revised accordingly under the following circumstances:
[391-3-1-.03(10)(d)1(i)]

a. If additional applicable requirements become applicable to the source and the remaining Permit term is three (3) or more years. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if the effective date of the requirement is later than the date on which the Permit is due to expire, unless the original permit or any of its terms and conditions has been extended under Condition 8.5.3;
[391-3-1-.03(10)(e)6(i)(I)]

b. If any additional applicable requirements of the Acid Rain Program become applicable to the source;
[391-3-1-.03(10)(e)6(i)(II)] (Acid Rain sources only)

c. The Director determines that the Permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of the Permit; or
[391-3-1-.03(10)(e)6(i)(III) and 40 CFR 70.7(f)(1)(iii)]

d. The Director determines that the Permit must be revised or revoked to assure compliance with the applicable requirements.
[391-3-1-.03(10)(e)6(i)(IV) and 40 CFR 70.7(f)(1)(iv)]

8.11.2 Proceedings to reopen and reissue a Permit shall follow the same procedures as applicable to initial Permit issuance and shall affect only those parts of the Permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable.
[391-3-1-.03(10)(e)6(ii)]

8.11.3 Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Director at least thirty (30) days in advance of the date the Permit is to be reopened, except that the Director may provide a shorter time period in the case of an emergency.
[391-3-1-.03(10)(e)6(iii)]

8.11.4 All Permit conditions remain in effect until such time as the Director takes final action. The filing of a request by the Permittee for any Permit revision, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, shall not stay any Permit condition.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(iii)]

8.11.5 A Permit revision shall not be required for changes that are explicitly authorized by the conditions of this Permit.

8.11.6 A Permit revision shall not be required for changes that are part of an approved economic incentive, marketable Permit, emission trading, or other similar program or process for change which is specifically provided for in this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(8)]

8.12 Severability

8.12.1 Any condition or portion of this Permit which is challenged, becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(5)]

8.13 Excess Emissions Due to an Emergency

8.13.1 An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the Permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(1)]

8.13.2 An emergency shall constitute an affirmative defense to an action brought for noncompliance with the technology-based emission limitations if the Permittee demonstrates, through properly signed contemporaneous operating logs or other relevant evidence, that:
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(2) and (3)]

a. An emergency occurred and the Permittee can identify the cause(s) of the emergency;

b. The Permitted facility was at the time of the emergency being properly operated;

c. During the period of the emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in the Permit; and

d. The Permittee promptly notified the Division and submitted written notice of the emergency to the Division within two (2) working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

8.13.3 In an enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency shall have the burden of proof.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(4)]

8.13.4 The emergency conditions listed above are in addition to any emergency or upset provisions contained in any applicable requirement.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(5)]

8.14 Compliance Requirements

8.14.1 Compliance Certification

The Permittee shall provide written certification to the Division and to the EPA, at least annually, of compliance with the conditions of this Permit. The annual written certification shall be postmarked no later than February 28 of each year and shall be submitted to the Division and to the EPA. The certification shall include, but not be limited to, the following elements:
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(5)]

a. The identification of each term or condition of the Permit that is the basis of the certification;

b. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent, based on the method or means designated in paragraph c below. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred;

c. The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period;

d. Any other information that must be included to comply with section 113(c)(2) of the Act, which prohibits knowingly making a false certification or omitting material information; and

e. Any additional requirements specified by the Division.

8.14.2 Inspection and Entry

a. Upon presentation of credentials and other documents as may be required by law, the Permittee shall allow authorized representatives of the Division to perform the following:
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(2)]

i. Enter upon the Permittee's premises where a Part 70 source is located or an emissions-related activity is conducted, or where records must be kept under the conditions of this Permit;
ii. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
iii. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this Permit; and
iv. Sample or monitor any substances or parameters at any location during operating hours for the purpose of assuring Permit compliance or compliance with applicable requirements as authorized by the Georgia Air Quality Act.

b. No person shall obstruct, hamper, or interfere with any such authorized representative while in the process of carrying out his official duties. Refusal of entry or access may constitute grounds for Permit revocation and assessment of civil penalties.
[391-3-1-.07 and 40 CFR 70.11(a)(3)(i)]

8.14.3 Schedule of Compliance

a. For applicable requirements with which the Permittee is in compliance, the Permittee shall continue to comply with those requirements.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(A)]

b. For applicable requirements that become effective during the Permit term, the Permittee shall meet such requirements on a timely basis unless a more detailed schedule is expressly required by the applicable requirement.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(B)]

c. Any schedule of compliance for applicable requirements with which the source is not in compliance at the time of Permit issuance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(C)]

8.14.4 Excess Emissions

a. Excess emissions resulting from startup, shutdown, or malfunction of any source which occur though ordinary diligence is employed shall be allowed provided that: [391-3-1-.02(2)(a)7(i)]

i. The best operational practices to minimize emissions are adhered to;

ii. All associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions; and

iii. The duration of excess emissions is minimized.

b. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction are prohibited and are violations of Chapter 391-3-1 of the Georgia Rules for Air Quality Control. [391-3-1-.02(2)(a)7(ii)]

c. The provisions of this condition and Georgia Rule 391-3-1-.02(2)(a)7 shall apply only to those sources which are not subject to any requirement under Georgia Rule 391-3-1-.02(8) – New Source Performance Standards or any requirement of 40 CFR, Part 60, as amended concerning New Source Performance Standards. [391-3-1-.02(2)(a)7(iii)]

8.15 Circumvention

State Only Enforceable Condition.

8.15.1 The Permittee shall not build, erect, install, or use any article, machine, equipment or process the use of which conceals an emission which would otherwise constitute a violation of an applicable emission standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of the pollutants in the gases discharged into the atmosphere. [391-3-1-.03(2)(c)]

8.16 Permit Shield

8.16.1 Compliance with the terms of this Permit shall be deemed compliance with all applicable requirements as of the date of Permit issuance provided that all applicable requirements are included and specifically identified in the Permit. [391-3-1-.03(10)(d)6]

8.16.2 Any Permit condition identified as "State only enforceable" does not have a Permit shield.

8.17 Operational Practices

8.17.1 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall maintain and operate the source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on any information available to the Division that may include, but is not limited to, monitoring results, observations of the opacity or other characteristics of emissions, review of operating and maintenance procedures or records, and inspection or surveillance of the source.
[391-3-1-.02(2)(a)10]

State Only Enforceable Condition.

8.17.2 No person owning, leasing, or controlling, the operation of any air contaminant sources shall willfully, negligently or through failure to provide necessary equipment or facilities or to take necessary precautions, cause, permit, or allow the emission from said air contamination source or sources, of such quantities of air contaminants as will cause, or tend to cause, by themselves, or in conjunction with other air contaminants, a condition of air pollution in quantities or characteristics or of a duration which is injurious or which unreasonably interferes with the enjoyment of life or use of property in such area of the State as is affected thereby. Complying with Georgia's Rules for Air Quality Control Chapter 391-3-1 and Conditions in this Permit, shall in no way exempt a person from this provision.
[391-3-1-.02(2)(a)1]

8.18 Visible Emissions

8.18.1 Except as may be provided in other provisions of this Permit, the Permittee shall not cause, let, suffer, permit or allow emissions from any air contaminant source the opacity of which is equal to or greater than forty (40) percent.
[391-3-1-.02(2)(b)1]

8.19 Fuel-burning Equipment

8.19.1 The Permittee shall not cause, let, suffer, permit, or allow the emission of fly ash and/or other particulate matter from any fuel-burning equipment with rated heat input capacity of less than 10 million Btu per hour, in operation or under construction on or before January 1, 1972 in amounts equal to or exceeding 0.7 pounds per million BTU heat input.
[391-3-1-.02(2)(d)]

8.19.2 The Permittee shall not cause, let, suffer, permit, or allow the emission of fly ash and/or other particulate matter from any fuel-burning equipment with rated heat input capacity of less than 10 million Btu per hour, constructed after January 1, 1972 in amounts equal to or exceeding 0.5 pounds per million BTU heat input.
[391-3-1-.02(2)(d)]

8.19.3 The Permittee shall not cause, let, suffer, permit, or allow the emission from any fuel-burning equipment constructed or extensively modified after January 1, 1972, visible emissions the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.
[391-3-1-.02(2)(d)]

8.20 Sulfur Dioxide

8.20.1 Except as may be specified in other provisions of this Permit, the Permittee shall not burn fuel containing more than 2.5 percent sulfur, by weight, in any fuel burning source that has a heat input capacity below 100 million Btu's per hour.
[391-3-1-.02(2)(g)]

8.21 Particulate Emissions

8.21.1 Except as may be specified in other provisions of this Permit, the Permittee shall not cause, let, permit, suffer, or allow the rate of emission from any source, particulate matter in total quantities equal to or exceeding the allowable rates shown below. Equipment in operation, or under construction contract, on or before July 2, 1968, shall be considered existing equipment. All other equipment put in operation or extensively altered after said date is to be considered new equipment.
[391-3-1-.02(2)(e)]

a. The following equations shall be used to calculate the allowable rates of emission from new equipment:

$E = 4.1P^{0.67}$; for process input weight rate up to and including 30 tons per hour.
$E = 55P^{0.11} - 40$; for process input weight rate above 30 tons per hour.

b. The following equation shall be used to calculate the allowable rates of emission from existing equipment:

$E = 4.1P^{0.67}$

In the above equations, E = emission rate in pounds per hour, and
P = process input weight rate in tons per hour.

8.22 Fugitive Dust
[391-3-1-.02(2)(n)]

8.22.1 Except as may be specified in other provisions of this Permit, the Permittee shall take all reasonable precautions to prevent dust from any operation, process, handling, transportation or storage facility from becoming airborne. Reasonable precautions that could be taken to prevent dust from becoming airborne include, but are not limited to, the following:

a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;

b. Application of asphalt, water, or suitable chemicals on dirt roads, materials, stockpiles, and other surfaces that can give rise to airborne dusts;

c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods can be employed during sandblasting or other similar operations;

d. Covering, at all times when in motion, open bodied trucks transporting materials likely to give rise to airborne dusts; and

e. The prompt removal of earth or other material from paved streets onto which earth or other material has been deposited.

8.22.2 The opacity from any fugitive dust source shall not equal or exceed 20 percent.

8.23 Solvent Metal Cleaning

8.23.1 Except as may be specified in other provisions of this Permit, the Permittee shall not cause, suffer, allow, or permit the operation of a cold cleaner degreaser unless the following requirements for control of emissions of the volatile organic compounds are satisfied: [391-3-1-.02(2)(ff)1]

a. The degreaser shall be equipped with a cover to prevent escape of VOC during periods of non-use,

b. The degreaser shall be equipped with a device to drain cleaned parts before removal from the unit,

c. If the solvent volatility is 0.60 psi or greater measured at 100 °F, or if the solvent is heated above 120 °F, then one of the following control devices must be used:

i. The degreaser shall be equipped with a freeboard that gives a freeboard ratio of 0.7 or greater, or

ii. The degreaser shall be equipped with a water cover (solvent must be insoluble in and heavier than water), or

iii. The degreaser shall be equipped with a system of equivalent control, including but not limited to, a refrigerated chiller or carbon adsorption system.

d. Any solvent spray utilized by the degreaser must be in the form of a solid, fluid stream (not a fine, atomized or shower type spray) and at a pressure which will not cause excessive splashing, and

e. All waste solvent from the degreaser shall be stored in covered containers and shall not be disposed of by such a method as to allow excessive evaporation into the atmosphere.

8.24 Incinerators

8.24.1 Except as specified in the section dealing with conical burners, no person shall cause, let, suffer, permit, or allow the emissions of fly ash and/or other particulate matter from any incinerator, in amounts equal to or exceeding the following:
[391-3-1-.02(2)(c)1-4]

a. Units with charging rates of 500 pounds per hour or less of combustible waste, including water, shall not emit fly ash and/or particulate matter in quantities exceeding 1.0 pound per hour.

b. Units with charging rates in excess of 500 pounds per hour of combustible waste, including water, shall not emit fly ash and/or particulate matter in excess of 0.20 pounds per 100 pounds of charge.

8.24.2 No person shall cause, let, suffer, permit, or allow from any incinerator, visible emissions the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.

8.24.3 No person shall cause or allow particles to be emitted from an incinerator which are individually large enough to be visible to the unaided eye.

8.24.4 No person shall operate an existing incinerator unless:

a. It is a multiple chamber incinerator;

b. It is equipped with an auxiliary burner in the primary chamber for the purpose of creating a pre-ignition temperature of 800°F; and

c. It has a secondary burner to control smoke and/or odors and maintain a temperature of at least 1500°F in the secondary chamber.

8.25 Volatile Organic Liquid Handling and Storage

8.25.1 The Permittee shall ensure that each storage tank subject to the requirements of Rule 391-3-1-.02(2)(vv) "Volatile Organic Liquid Handling and Storage" is equipped with submerged fill pipes. For the purposes of this condition and the permit, a submerged fill pipe is defined as any fill pipe with a discharge opening which is within six inches of the tank bottom.
[391-3-1-.02(2)(vv)(1)]

8.26 Use of Any Credible Evidence or Information

8.26.1 Notwithstanding any other provisions of any applicable rule or regulation or requirement of this permit, for the purpose of submission of compliance certifications or establishing whether or not a person has violated or is in violation of any emissions limitation or standard, nothing in this permit or any Emission Limitation or Standard to which it pertains, shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.
[391-3-1-.02(3)(a)]

8.27 Diesel-Fired Internal Combustion Engines

8.27.1 The Permittee shall comply with all applicable provisions of New Source Performance Standards (NSPS) Federal Rule 40 CFR Part 60 Subpart A-"General Provisions" and Subpart IIII-"Standards for Stationary Compression Ignition Internal Combustion Engines," for diesel-fired internal combustion engine(s) manufactured after April 1, 2006 or modified/reconstructed after July 11, 2005. Such requirements include but are not limited to:
[40 CFR 60.4205(b), 391-3-1-.02(8)(b)77]

a. Equip all emergency generator engines with non-resettable hour meters.

b. Purchase only diesel fuel with a maximum sulfur content of 15 ppm unless otherwise specified by the Division.

Attachments

A. List of Standard Abbreviations and List of Permit Specific Abbreviations
B. Insignificant Activities Checklist, Insignificant Activities Based on Emission Levels and Generic Emission Groups
C. List of References
D. U.S. EPA Acid Rain Program Phase II Permit Application
E. CAIR Permit Application for SO_2 and NO_X Annual Trading Programs

ATTACHMENT A

List Of Standard Abbreviations

AIRS	Aerometric Information Retrieval System
APCD	Air Pollution Control Device
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BTU	British Thermal Unit
CAAA	Clean Air Act Amendments
CEMS	Continuous Emission Monitoring System
CERMS	Continuous Emission Rate Monitoring System
CFR	Code of Federal Regulations
CMS	Continuous Monitoring System(s)
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
dscf/dscm	Dry Standard Cubic Foot / Dry Standard Cubic Meter
EPA	United States Environmental Protection Agency
EPCRA	Emergency Planning and Community Right to Know Act
gr	Grain(s)
GPM (gpm)	Gallons per minute
H_2O (H2O)	Water
HAP	Hazardous Air Pollutant
HCFC	Hydro-chloro-fluorocarbon
MACT	Maximum Achievable Control Technology
MMBtu	Million British Thermal Units
MMBtu/hr	Million British Thermal Units per hour
MVAC	Motor Vehicle Air Conditioner
MW	Megawatt
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x (NOx)	Nitrogen Oxides
NSPS	New Source Performance Standards
OCGA	Official Code of Georgia Annotated

PM	Particulate Matter
PM_{10} (PM10)	Particulate Matter less than 10 micrometers in diameter
PPM (ppm)	Parts per Million
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RMP	Risk Management Plan
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2 (SO2)	Sulfur Dioxide
USC	United States Code
VE	Visible Emissions
VOC	Volatile Organic Compound

List of Permit Specific Abbreviations

PCB	Polychlorinated Biphenyl
ESP	Electrostatic Precipitator
SCR	Selective Catalytic Reduction

ng	nanograms
J	Joule
ID	Identification
FGD	Flue Gas Desulfurization

ATTACHMENT B

NOTE: Attachment B contains information regarding insignificant emission units/activities and groups of generic emission units/activities in existence at the facility at the time of Permit issuance. Future modifications or additions of insignificant emission units/activities and equipment that are part of generic emissions groups may not necessarily cause this attachment to be updated.

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Mobile Sources	1. Cleaning and sweeping of streets and paved surfaces	X
Combustion Equipment	1. Fire fighting and similar safety equipment used to train fire fighters or other emergency personnel.	X
	2. Small incinerators that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act and are not considered a "designated facility" as specified in 40 CFR 60.32e of the Federal emissions guidelines for Hospital/Medical/Infectious Waste Incinerators, that are operating as follows: i) Less than 8 million BTU/hr heat input, firing types 0, 1, 2, and/or 3 waste.	
	ii) Less than 8 million BTU/hr heat input with no more than 10% pathological (type 4) waste by weight combined with types 0, 1, 2, and/or 3 waste.	
	iii) Less than 4 million BTU/hr heat input firing type 4 waste. (Refer to 391-3-1-.03(10)(g)2.(ii) for descriptions of waste types)	
	3. Open burning in compliance with Georgia Rule 391-3-1-.02 (5).	X
	4. Stationary engines burning: i) Natural gas, LPG, gasoline, dual fuel, or diesel fuel which are used exclusively as emergency generators shall not exceed 500 hours per year or 200 hours per year if subject to Georgia Rule 391-3-1-.02(2)(mmm).7	3
	ii) Natural gas, LPG, and/or diesel fueled generators used for emergency, peaking, and/or standby power generation, where the combined peaking and standby power generation do not exceed 200 hours per year.	
	iii) Natural gas, LPG, and/or diesel fuel used for other purposes, provided that the output of each engine does not exceed 400 horsepower and that no individual engine operates for more than 2,000 hours per year.	2
	iv) Gasoline used for other purposes, provided that the output of each engine does not exceed 100 horsepower and that no individual engine operates for more than 500 hours per year.	
Trade Operations	1. Brazing, soldering, and welding equipment, and cutting torches related to manufacturing and construction activities whose emissions of hazardous air pollutants (HAPs) fall below 1,000 pounds per year.	X
Maintenance, Cleaning, and Housekeeping	1. Blast-cleaning equipment using a suspension of abrasive in water and any exhaust system (or collector) serving them exclusively.	
	2. Portable blast-cleaning equipment.	X
	3. Non-Perchloroethylene Dry-cleaning equipment with a capacity of 100 pounds per hour or less of clothes.	
	4. Cold cleaners having an air/vapor interface of not more than 10 square feet and that do not use a halogenated solvent.	5
	5. Non-routine clean out of tanks and equipment for the purposes of worker entry or in preparation for maintenance or decommissioning.	X
	6. Devices used exclusively for cleaning metal parts or surfaces by burning off residual amounts of paint, varnish, or other foreign material, provided that such devices are equipped with afterburners.	
	7. Cleaning operations: Alkaline phosphate cleaners and associated cleaners and burners.	

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Laboratories and Testing	1. Laboratory fume hoods and vents associated with bench-scale laboratory equipment used for physical or chemical analysis.	6
	2. Research and development facilities, quality control testing facilities and/or small pilot projects, where combined daily emissions from all operations are not individually major or are support facilities not making significant contributions to the product of a collocated major manufacturing facility.	
Pollution Control	1. Sanitary waste water collection and treatment systems, except incineration equipment or equipment subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	3
	2. On site soil or groundwater decontamination units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
	3. Bioremediation operations units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
	4. Landfills that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	2
Industrial Operations	1. Concrete block and brick plants, concrete products plants, and ready mix concrete plants producing less than 125,000 tons per year.	
	2. Any of the following processes or process equipment which are electrically heated or which fire natural gas, LPG or distillate fuel oil at a maximum total heat input rate of not more than 5 million BTU's per hour: i) Furnaces for heat treating glass or metals, the use of which do not involve molten materials or oil-coated parts.	
	ii) Porcelain enameling furnaces or porcelain enameling drying ovens.	
	iii) Kilns for firing ceramic ware.	
	iv) Crucible furnaces, pot furnaces, or induction melting and holding furnaces with a capacity of 1,000 pounds or less each, in which sweating or distilling is not conducted and in which fluxing is not conducted utilizing free chlorine, chloride or fluoride derivatives, or ammonium compounds.	
	v) Bakery ovens and confection cookers.	
	vi) Feed mill ovens.	
	vii) Surface coating drying ovens	
	3. Carving, cutting, routing, turning, drilling, machining, sawing, surface grinding, sanding, planing, buffing, shot blasting, shot peening, or polishing; ceramics, glass, leather, metals, plastics, rubber, concrete, paper stock or wood, also including roll grinding and ground wood pulping stone sharpening, provided that: i) Activity is performed indoors; & ii) No significant fugitive particulate emissions enter the environment; & iii) No visible emissions enter the outdoor atmosphere.	X
	4. Photographic process equipment by which an image is reproduced upon material sensitized to radiant energy (e.g., blueprint activity, photographic developing and microfiche).	
	5. Grain, food, or mineral extrusion processes	
	6. Equipment used exclusively for sintering of glass or metals, but not including equipment used for sintering metal-bearing ores, metal scale, clay, fly ash, or metal compounds.	
	7. Equipment for the mining and screening of uncrushed native sand and gravel.	
	8. Ozonization process or process equipment.	
	9. Electrostatic powder coating booths with an appropriately designed and operated particulate control system.	
	10. Activities involving the application of hot melt adhesives where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	
	11. Equipment used exclusively for the mixing and blending water-based adhesives and coatings at ambient temperatures.	
	12. Equipment used for compression, molding and injection of plastics where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	
	13. Ultraviolet curing processes where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Storage Tanks and Equipment	1. All petroleum liquid storage tanks storing a liquid with a true vapor pressure of equal to or less than 0.50 psia as stored.	3
	2. All petroleum liquid storage tanks with a capacity of less than 40,000 gallons storing a liquid with a true vapor pressure of equal to or less than 2.0 psia as stored that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	2
	3. All petroleum liquid storage tanks with a capacity of less than 10,000 gallons storing a petroleum liquid.	17
	4. All pressurized vessels designed to operate in excess of 30 psig storing petroleum fuels that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	3
	5. Gasoline storage and handling equipment at loading facilities handling less than 20,000 gallons per day or at vehicle dispensing facilities that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	1
	6. Portable drums, barrels, and totes provided that the volume of each container does not exceed 550 gallons.	175
	7. All chemical storage tanks used to store a chemical with a true vapor pressure of less than or equal to 10 millimeters of mercury (0.19 psia).	14

INSIGNIFICANT ACTIVITIES BASED ON EMISSION LEVELS

Description of Emission Units / Activities	Quantity
Cooling Towers	4

ATTACHMENT B (continued)

GENERIC EMISSION GROUPS

Emission units/activities appearing in the following table are subject only to one or more of Georgia Rules 391-3-1-.02 (2) (b), (e) &/or (n). Potential emissions of particulate matter, from these sources based on TSP, are less than 25 tons per year per process line or unit in each group. Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Emissions Units / Activities	Number of Units (if appropriate)	Applicable Rules		
		Opacity Rule (b)	PM from Mfg Process Rule (e)	Fugitive Dust Rule (n)
N/A				

The following table includes groups of fuel burning equipment subject only to Georgia Rules 391-3-1-.02 (2) (b) & (d).Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Fuel Burning Equipment	Number of Units
Fuel burning equipment with a rated heat input capacity of less than 10 million BTU/hr burning only natural gas and/or LPG.	0
Fuel burning equipment with a rated heat input capacity of less than 5 million BTU/hr, burning only distillate fuel oil, natural gas and/or LPG.	0
Any fuel burning equipment with a rated heat input capacity of 1 million BTU/hr or less.	0

ATTACHMENT C

LIST OF REFERENCES

1. The Georgia Rules for Air Quality Control Chapter 391-3-1. All Rules cited herein which begin with 391-3-1 are State Air Quality Rules.

2. Title 40 of the Code of Federal Regulations; specifically 40 CFR Parts 50, 51, 52, 60, 61, 63, 64, 68, 70, 72, 73, 75, 76 and 82. All rules cited with these parts are Federal Air Quality Rules.

3. ***Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Procedures for Testing and Monitoring Sources of Air Pollutants.***

4. ***Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Procedures for Calculating Air Permit Fees***.

5. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources. This information may be obtained from EPA's TTN web site at *www.epa.gov/ttn/chief/ap42/index.html.*

6. The latest properly functioning version of EPA's **TANKS** emission estimation software. The software may be obtained from EPA's TTN web site at *www.epa.gov/ttn/chief/software/tanks/index.html.*

7. The Clean Air Act (42 U.S.C. 7401 et seq).

8. White Paper for Streamlined Development of Part 70 Permit Applications, July 10, 1995 (White Paper #1).

9. White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program, March 5, 1996 (White Paper #2).

ATTACHMENT D

U.S. EPA ACID RAIN PROGRAM
PHASE II PERMIT APPLICATION

RECEIVED

JUN 2 9 2011

AIR PROTECTION BRANCH

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

EPA

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ~ new ~ revised X for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name: Wansley	State: GA	Plant Code: 6052

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes

Facility (Source) Name (from STEP 1): Wansley

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the

submission of a new certificate of representation changing the designated representative;

STEP 3, Cont'd. **Recordkeeping and Reporting Requirements, Cont'd.**

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

Facility (Source) Name (from STEP 1): Wansley

STEP 3, Cont'd.

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements
under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Ronald Shipman	
Signature Ronald Shipman	Date 6/27/2011

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DEC 2 2008

AIR PROTECTION BRANCH

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Phase II NO_x Averaging Plan

For more information, see instructions and refer to 40 CFR 76.11

This submission is: [ ] New [X] Revised

STEP 1

Identify the units participating in this averaging plan by plant name, State, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation (ACEL) in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) ACEL	(c) Annual Heat Input Limit
See Page 3.					

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.46	≤	0.46

$$\frac{\sum_{i=1}^{n}(R_{Li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n}[R_{li} \times HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emission limitation for unit i, in lb/mmBtu, as specified in column (b) of Step 1;

R_{li} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

Southern Company Averaging Plan

Participating Plants

Plant Name (from Step 1)

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year __________ through calendar year __________ unless notification to terminate the plan is given.

☒ Treat this plan as 5 identical plans, each effective for one calendar year for the following calendar years: 2009, 2010, 2011, 2012 and 2013 unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO$_x$ under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Chris M. Hobson	
Signature	Date 7/15/08

Southern Company Averaging Plan Participating Plants
Plant Name (from Step 1) as Listed in Step 1.

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Barry	AL	1	0.40	0.57	9,860,460
Barry	AL	2	0.40	0.57	8,697,917
Barry	AL	3	0.40	0.57	15,390,498
Barry	AL	4	0.40	0.45	26,579,698
Barry	AL	5	0.40	0.45	41,811,371
Bowen	GA	1	0.45	0.42	43,857,264
Bowen	GA	2	0.45	0.43	52,033,363
Bowen	GA	3	0.45	0.43	60,747,005
Bowen	GA	4	0.45	0.43	60,245,171
Branch	GA	1	0.68	0.99	15,903,035
Branch	GA	2	0.50	0.72	20,954,063
Branch	GA	3	0.68	0.84	34,483,187
Branch	GA	4	0.68	0.84	29,893,099
Crist	FL	4	0.45	0.52	5,306,563
Crist	FL	5	0.45	0.60	5,321,833
Crist	FL	6	0.50	0.45	22,068,817
Crist	FL	7	0.50	0.45	36,700,987
Daniel	MS	1	0.45	0.33	40,792,453
Daniel	MS	2	0.45	0.33	34,210,453
Gadsden	AL	1	0.45	0.75	2,568,523
Gadsden	AL	2	0.45	0.75	3,084,694
Gaston	AL	1	0.50	0.52	15,475,515
Gaston	AL	2	0.50	0.52	13,226,420
Gaston	AL	3	0.50	0.52	17,263,124
Gaston	AL	4	0.50	0.52	16,744,074
Gaston	AL	5	0.45	0.48	56,376,964
Gorgas	AL	6	0.46	0.55	5,698,165
Gorgas	AL	7	0.46	0.55	6,140,227
Gorgas	AL	8	0.40	0.52	13,186,388
Gorgas	AL	9	0.40	0.52	14,567,087
Gorgas	AL	10	0.40	0.52	55,157,733

Southern Company Averaging Plan Participating Plants
as Listed in Step 1.

Plant Name (from Step 1)

NO$_x$ Averaging - Page 4

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Greene Co	AL	1	0.68	0.60	16,688,168
Greene Co	AL	2	0.46	0.60	19,915,731
Hammond	GA	1	0.50	0.83	6,702,621
Hammond	GA	2	0.50	0.83	7,697,469
Hammond	GA	3	0.50	0.83	6,610,570
Hammond	GA	4	0.50	0.45	29,007,730
Kraft	GA	1	0.45	0.58	3,195,641
Kraft	GA	2	0.45	0.58	2,991,096
Kraft	GA	3	0.45	0.58	5,936,838
L. Smith	FL	1	0.40	0.62	13,643,808
L. Smith	FL	2	0.40	0.44	14,784,899
McDonough	GA	1	0.45	0.42	16,633,061
McDonough	GA	2	0.45	0.42	16,753,801
McIntosh	GA	1	0.50	0.86	9,215,784
Miller	AL	1	0.46	0.37	54,272,966
Miller	AL	2	0.46	0.37	52,981,813
Miller	AL	3	0.46	0.28	58,020,776
Miller	AL	4	0.46	0.28	56,910,001
Mitchell	GA	3	0.45	0.62	6,001,510
Scherer	GA	1	0.40	0.50	71,791,890
Scherer	GA	2	0.40	0.50	71,474,044
Scherer	GA	3	0.45	0.29	53,390,136
Scherer	GA	4	0.40	0.30	53,390,136
Scholz	FL	1	0.50	0.68	2,083,631
Scholz	FL	2	0.50	0.77	2,118,168
Wansley	GA	1	0.45	0.41	63,896,521
Wansley	GA	2	0.45	0.42	56,607,431
Watson	MS	4	0.50	0.60	13,463,120
Watson	MS	5	0.50	0.42	35,382,214
Yates	GA	1	0.45	0.48	5,477,394
Yates	GA	2	0.45	0.48	4,879,349
Yates	GA	3	0.45	0.48	4,830,444
Yates	GA	4	0.45	0.40	8,031,999
Yates	GA	5	0.45	0.40	7,240,618
Yates	GA	6	0.45	0.33	21,932,927
Yates	GA	7	0.45	0.30	19,834,248

ATTACHMENT E

CAIR PERMIT APPLICATION FOR SO_2 and NO_x ANNUAL TRADING PROGRAMS

CAIR Permit Application
(for sources covered under a CAIR SIP)

For more information, refer to 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, and 96.322

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18675
AIR PROTECTION BRANCH

This submission is: X New Revised

STEP 1
Identify the source by plant name, State, and ORIS or facility code

Plant Name	State	ORIS/Facility Code
Wansley	GA	6052

STEP 2
Enter the unit ID# for each CAIR unit and indicate to which CAIR programs each unit is subject (by placing an "X" in the column)

Unit ID#	NO_X Annual	SO_2	NO_X Ozone Season
1	X	X	
2	X	X	
5A	X	X	
6A	X	X	
6B	X	X	
7A	X	X	
7B	X	X	

STEP 3
Read the standard requirements and the certification, enter the name of the CAIR designated representative, and sign and date

Standard Requirements

(a) Permit Requirements.

(1) The CAIR designated representative of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.122, §96.222, and §96.322 (as applicable) in accordance with the deadlines specified in §96.121, §96.221, and §96.321 (as applicable); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC, CCC, and CCCC (as applicable) of 40 CFR part 96 for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II, III, and IIII (as applicable) of 40 CFR part 96, the owners and operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) that is not otherwise required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC, CCC, and CCCC (as applicable) of 40 CFR part 96 for such CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and such CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable).

Wansley
Plant Name (from Step 1)

STEP 3, continued

(b) Monitoring, reporting, and recordkeeping requirements.
(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96.
(2) The emissions measurements recorded and reported in accordance with subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96 shall be used to determine compliance by each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) with the CAIR NO_X emissions limitation, CAIR SO_2 emissions limitation, and CAIR NO_X Ozone Season emissions limitation (as applicable) under paragraph (c) of §96.106, §96.206, and §96.306 (as applicable).

(c) Nitrogen oxides emissions requirements.
(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under §96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with subpart HH of 40 CFR part 96.
(2) A CAIR NO_X unit shall be subject to the requirements under paragraph (c)(1) of §96.106 for the control period starting on the later of January 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.170(b)(1), (2), or (5) and for each control period thereafter.
(3) A CAIR NO_X allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.106, for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.
(4) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Allowance Tracking System accounts in accordance with subparts FF, GG, and II of 40 CFR part 96.
(5) A CAIR NO_X allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Annual Trading Program. No provision of the CAIR NO_X Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.
(6) A CAIR NO_X allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO_X unit.
Sulfur dioxide emission requirements.
(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under §96.254(a) and (b) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with subpart HHH of 40 CFR part 96.
(2) A CAIR SO_2 unit shall be subject to the requirements under paragraph (c)(1) of §96.206 for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under §96.270(b)(1), (2), or (5) and for each control period thereafter.
(3) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.206, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.
(4) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of 40 CFR part 96.
(5) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.
(6) A CAIR SO_2 allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR SO_2 unit.
Nitrogen oxides ozone season emissions requirements.
(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under §96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with subpart HHHH of 40 CFR part 96.
(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of §96.306 for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.370(b)(1), (2), (3) or (7) and for each control period thereafter.
(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.306, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.
(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with subparts FFFF, GGGG, and IIII of 40 CFR part 96.
(5) A CAIR NO_X allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.
(6) A CAIR NO_X allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

STEP 3, continued

(d) Excess emissions requirements.
If a CAIR NO_X source emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X unit at the source shall surrender the CAIR NO_X allowances required for deduction under §96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

If a CAIR SO_2 source emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under §96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

If a CAIR NO_X Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and Reporting Requirements.
(1) Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §96.113, §96.213, and §96.313 (as applicable) for the CAIR designated representative for the source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.113, §96.213, and §96.313 (as applicable) changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96, provided that to the extent that subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) or to demonstrate compliance with the requirements of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).
(2) The CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall submit the reports required under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) including those under subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96.

(f) Liability.
(1) Each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) shall meet the requirements of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).
(2) Any provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) that applies to a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) or the CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) shall also apply to the owners and operators of such source and of the CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X Ozone Season units (as applicable) at the source.
(3) Any provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) that applies to a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) or the CAIR designated representative of a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) shall also apply to the owners and operators of such unit.

Wansley Plant Name (from Step 1)

STEP 3, continued

(g) Effect on Other Authorities.
No provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable), a CAIR permit application, a CAIR permit, or an exemption under § 96.105, §96.205, and §96.305 (as applicable) shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) or CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

Certification

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Charles H. Huling Name	
Signature Charles H. Huling	12/12/2008 Date

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EXHIBIT B

GreenLaw®

Giving Georgia's Environment Its Day In Court

VIA EMAIL DELIVERY

Mr. Eric Cornwell
Manager, Stationary Source Permitting Program
Georgia Air Protection Branch
4244 International Parkway, Suite 120
Atlanta, GA 30354

Re: Draft Renewal Title V Major Source Operating Permit for the Wansley Steam-Electric Generating Plant, Permit No. 4911-149-0001-V-03-0

Dear Mr. Cornwell:

GreenLaw respectfully submits the following comments on the draft Major Source Operating Permit ("Draft Permit") for Southern Company/Georgia Power Company's ("SC/GPC") Wansley Steam-Electric Generating Plant on behalf of Fall-line Alliance for a Clean Environment [1], Ogeechee Riverkeeper,[2] Southern Alliance for Clean Energy[3] and Sierra Club.[4] The Draft Permit has been placed on public notice for Clean Air Act ("CAA" or "Act") Title V permit renewal by the Georgia Environmental Protection Division ("EPD"). We appreciate the opportunity to submit these comments.

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[1] Fall-line Alliance for a Clean Environment ("FACE") is an organization of 200 members and supporters that has been at the forefront of investigation, education, and advocacy for a safe and clean environment for the Middle Georgia area identified geographically as the Fall Line. FACE's primary work focuses on the threat posed by coal-generated power, and specifically the toxic pollutants emitted by coal-fired power plants and impacts from these pollutants on the quality and availability of water supplies. The organization has also been active on issues including landfills, tire incinerators, and land use.

[2] Ogeechee Riverkeeper ("ORK") is membership corporation with approximately 1400 members. ORK's mission is to protect, preserve and improve the water quality of the Ogeechee River basin. One of the pollution concerns in the Ogeechee River basin is due to mercury, which is emitted in large quantities by power plants.

[3] Southern Alliance for Clean Energy ("SACE") has been a leading voice for energy policy to protect the quality of life and treasured places in the Southeast since 1985. http://www.cleanenergy.org/index.php?/Who-We-Are.html.

[4] Sierra Club is a national nonprofit organization with over 1.3 million members nationwide. The Georgia chapter has 117,000 members in Georgia, some of whom live, work, and recreate in the vicinity of Plant Wansley and/or in areas impacted by emissions from the Plant. The mission of Sierra Club is to explore, enjoy and protect the wild places of the earth, practice and promote the responsible use of the Earth's ecosystems and resources, educate and enlist humanity to protect and restore the quality of the natural and human environment, and use all lawful means to carry out these objectives.

I. Background

The Wansley Electric Generating Plant ("Plant Wansley" or "Plant") is situated on 5,200 acres near Carrollton, Georgia. Plant Wansley consists of two 865 megawatt coal-fired units, one 60 megawatt oil-fired combustion turbine burning No. 2 fuel oil, and four natural gas-fired combined-cycle power blocks. The draft permit covers only the two coal-fired units and the oil-fired combustion turbine.

Emissions from the two coal-fired units are controlled by flue gas sulfurization for the control of sulfur dioxide ("SO_2") emissions, selective catalytic reduction for the control of nitrogen oxide ("NO_X") emissions, and electrostatic precipitators ("ESPs"). Emissions from the oil-fired combustion unit are controlled by water injection.

During normal operation, each of the coal-fired units exhaust to separate liners within a single stack[5]; the combustion turbine has its own 32-ft exhaust. Draft Permit at 1. During bypass, it appears that the steam-generating units exhaust to separate liners within another stack. Permit Application at A7.

The previous Title V permit for the Plant expired on January 1, 2012. 2007 Title V Permit at 1. EPD received SC/GPC's application for renewal of the Title V permit for the Plant on June 29, 2011. Narrative at 1. EPD issued for public notice the Draft Permit and an accompanying Narrative for this facility. The deadline for public comment is May 18, 2012.

II. Regulatory Framework

All major stationary sources of air pollution are required to apply for operating permits under Title V of the CAA. These permits must include emission limitations and other conditions necessary to assure continuous compliance with all applicable requirements of the Act, including the requirements of the applicable State Implementation Plan ("SIP"). See 42 U.S.C. §§ 7661a(a) and 7661c(a). The Title V operating permit program does not generally impose new substantive air quality control requirements but does require that permits contain monitoring, recordkeeping, reporting, and other requirements to assure continuous compliance by sources with all existing applicable emission control requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992) (EPA final action promulgating Part 70 rule). One purpose of the Title V program is to "enable the source, states, EPA, and the public to better understand the requirements to which the source is subject, and whether the source is meeting those requirements." Id. Thus, the Title V program is a vehicle to ensure appropriate application of and compliance with applicable CAA requirements.

The regulations require each Title V permit to include "[e]missions limitations and standards, including those operational requirements and limitations that assure compliance with

[5] There appears to be some contradiction between the application and the permit as to the exhaust during normal and bypass operations. See below, section IVd.

all applicable requirements at the time of permit issuance." See Ga. Comp. R. & Regs. r. 391-3-1-.03(10)(d)1(i) (incorporating by reference 40 C.F.R. § 70.6(a)) (emphasis added). Permits must also include "[a]ll emissions monitoring and analysis procedures or test methods required," and "periodic monitoring sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit." See id. Monitoring requirements must "assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement." Ga. Comp. R. & Regs. r. 391-3-1-.03(10)(d)3 (incorporating by reference 40 C.F.R. § 70.6(c)); see 40 C.F.R. § 70.6(c)(1) (requiring "compliance certification, testing, monitoring, reporting and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit").

A Title V permit is issued for a term of no more than five years, 40 C.F.R. § 70.6(a), and the applicant must submit an application for renewal of the permit "at least 6 months prior to the date of permit expiration, or such other longer time as may be approved by the Administrator that ensures that the term of the permit will not expire before the permit is renewed." 40 C.F.R. § 70.5(a)(1)(iii). Permit renewals are subject to the same procedural requirements, including those for public participation and EPA review that apply to initial permit issuance. 40 C.F.R. § 70.7(c)(1)(i). Permitting authorities should analyze timely filed renewal applications and issue renewed permits *prior to expiration* of the existing Title V permit.

III. Address

The Plant is physically situated on 5,200 acres located in Carroll and Heard counties, and thus should be subject to nonattainment standards in both counties. As Carroll County is nonattainment for particulate matter less than 2.5 micrometers ("$PM_{2.5}$"), and Carroll County is nonattainment for ozone, the Draft Permit should incorporate standards for major facilities in nonattainment areas for both pollutants. Narrative at 2, 10.

As currently drafted, the permit contains nonattainment provisions for ozone, but not for $PM_{2.5}$. See Narrative at 10. The provisions responding to $PM_{2.5}$ should be revised to reflect that the Plant lies within a nonattainment area for $PM_{2.5}$ as well.

IV. The Draft Permit is Incomplete

The Draft Permit does not fulfill the Title V program's fundamental purpose: to consolidate in a single document all CAA requirements that apply to a source. The lack of information and clarity undermines the central purpose of the Title V program, which is to allow the "source, States, EPA and the public to better understand the requirements to which the source is subject, and whether the source is meeting those requirements." 57 Fed. Reg. 32250, 32251 (July 21, 1992).

a. Ownership and Operational Units

The Draft Permit should clearly identify the entities responsible for liability imposed on the Plant under the Clean Air Act and Georgia statutes and regulations. Further, the Draft Permit should be revised to include all activities on the Title V site.

The current Draft Permit does not discuss ownership of the Plant, resulting in ambiguity as to which corporate entities are bound by the terms of the Draft Permit, and whether EPD can practically enforce such terms. According to Georgia Power, the units covered within the Draft Permit (Units 1, 2, and 5A) are jointly owned by Georgia Power, Oglethorpe Power, MEAG Power and the City of Dalton. February 14, 2007 Georgia Power Petition to Have the Administrator Object to Wansley Steam-Electric Generating Plant's Title V Permit ("2007 Wansley Petition"), available at http://www.epa.gov/region7/air/title5/petitiondb/petitions/gapower_wansley_petition2008.pdf (last accessed May 18, 2010) at 3. However, while it appears that only the "Permittee" is bound by the terms and conditions of the Draft Permit, that term is undefined within the Draft Permit. This lack of definition results in an ambiguity as to whether the "Permittee" is Plant Wansley and thus comprised of the four entities discussed above, or if the "Permittee" is SC/GPC and thus no liability can be imposed on the other three entities that own Plant Wansley. This lack a specific definition, as well as discussion regarding the other owners, could lead to administrative inefficiency and waste of resources should EPD find that enforcement against the "Permittee" is required. This should be addressed in the final permit by including a precise definition of "Permittee," which should include both a discussion of the various owners and a provision stating that Georgia Power is primarily charged with all liability on the units covered by the Draft Permit.

Further, the Draft Permit is incomplete because it does not include the other units that make up the entire Title V site. See Draft Permit at 1. Title V of the Clean Air Act defines "major source" as "any stationary source (or any group of stationary sources located within a contiguous area and under common control)" that is also a major source as defined by Section 112 or the General Provisions of the Act. 42 U.S.C. § 7661(2) (citing 42 U.S.C. § 7412 and 42 U.S.C. § 7602, defining criteria and hazardous pollutant thresholds for "major" sources). The EPA has previously found that property ownership and corporate ownership are both independently sufficient to find "common control." See Sierra Club v. EPA, 496 F.3d 1182, 1188 (11th Cir. 2007) (finding that Georgia Power and Oglethorpe share ownership of Plant Sherer Units 1 & 2 and discussing EPA's evaluation of Oglethorpe's compliance history under theory that Oglethorpe controlled said units); see also, 2007 Wansley Petition at 8 ("Ownership Interests. Common control can be established through (corporate or property) ownership.") (citing to Letter to Mr. Michael L. Rodburg, Lowenstein, Sandler, Kohl, Fisher & Boylan from Steven C. Riva, Chief, Permitting Section, Air Programs Branch, U.S. EPA Region 2 (November 25, 1997)). Since MEAG and Oglethorpe Power control Units 1, 2, and 5A by ownership interests in those units, and Southern Power and Georgia Power have a "corporate relationship" as both are owned by Southern Company, there is common control throughout the units that comprise the Title V site. See 2007 Wansley Petition at 3. As a result of this common control, the Title V permit should be revised to include the other units that comprise the Title V site, namely, those units identified under AFS No. 149-00001, 149-00011, 149-00006, 149-00007.

Additionally, the Draft Permit is incomplete because it does not include the activities of the ash-processing facility, treating it as a separate, and thus minor, source of air pollutants. Draft Permit at 1. Although the ash processing facility is not operated by GPC, this is not enough to make it a separately regulated source. As discussed in the preceding paragraph, Title V defines "major source" to include contiguous property under common control. EPD reasons that even though the ash processing facility is "contiguous" to the Plant, there is "no common control." Draft Permit at 1. However, the Plant cannot continue to operate without some sort of ash processing or disposal, and it must not be artificially segmented in order to escape applicable regulations or to disaggregate the relevant applicable regulations into different permits. As phrased in the Draft Permit, "Plant Wansley is currently contracting with an ash processing facility located on site. . . ." Id. GPC asserts control through the terms of the contract. The ash-processing facility is only one of the ancillary facilities that could potentially be contracted out by the Plant's operator, and it is inappropriate to treat any subpart of the Plant as a separate source simply because GP has contracted with another entity to process its waste.

b. Megawatt Capacity and Heat Input Rates

The narrative lists the "maximum heat input capacity" for each of the primarily coal-fired steam generating units as 9420 million British Thermal Units per hour ("MMBtu/hr") and for the combustion turbine unit 5A as 904 MMBtu/hr. Narrative at 8.

It is not clear that any of the above values represent a maximum allowable heat input for each unit, nor is any such value stated in the Draft Permit. It is essential to the integrity of the Draft Permit's emissions limitations that the maximum allowable heat inputs be stated clearly in the Title V permit. Heat input values and pollutant emission factors are used to estimate the maximum emissions of pollutants from the Plant. Pollutant emission rates or limits are expressed as pounds per MMBtu ("lb/MMBtu") heat input. Thus, both the legal limit on emissions and the amount of pollutants actually emitted change in proportion to the heat input, all other things being equal. Without maximum hourly heat input values, the Draft Permit fails to inform the public of the amount of pollutants the Plant will potentially emit on a short-term basis, and fails to inform as to the quantity of emissions that can be emitted on a short-term basis by each Unit. Stating maximum heat input values in the Narrative is not sufficient because, as the Narrative states, it is provided merely "as an adjunct for the reviewer and to provide information" and "has no legal standing." Narrative at 1.

c. Unclear and Incomplete Permit Terms

The Draft Permit purports to be a stand-alone document, stating on its face that it is "subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached **57** pages." Draft Permit cover page (emphasis in original). However, the Draft Permit and Narrative both reference the requirements of other key documents that are not contained within the four corners of the Draft Permit. This creates confusion about what in fact constitutes the permit and whether requirements that lie outside the fifty-seven pages of the permit are practically and federally enforceable. The permit must incorporate and consolidate all applicable requirements, and the public must have adequate notice of precisely what constitutes the Draft Permit.

d. The Permit Must Address, Define and Limit Bypass Operations

The application submitted by Georgia Power states "[s]team generating unit 1 and 2 each exhaust through separate liners of the 675 foot stack, except when in bypass mode when they each exhaust through separate liners of the 1000 foot stack." Application at A7. However, section 1.3 (Overall Facility Process Description) of the Draft Permit only discusses exhaust through the 1000 foot stack, with no discussion of exhaust during bypass operations. Draft Permit at 1 ("Each steam generating unit exhausts through its own stack liner in the 1000-ft stack."). This inconsistency should be corrected by clarifying the facility processes during bypass operations.

Further, although the Draft Permit does mention a "scrubber bypass stack," neither the Narrative nor the Draft Permit explains or defines the circumstances under which bypassing the scrubber is allowed. Bypass of the scrubber should only be allowed under those circumstances exempted by Rules (sss) and (uuu) – otherwise, the Draft Permit violates those rules. At a minimum, the Draft Permit should be revised to clarify that scrubber bypass is not permitted outside of the exceptions contained in paragraph 20 of Rule (sss) (as revised) and paragraph 4 of Rule (uuu). Moreover, those exceptions should be limited and clarified as suggested in Section VI, below, so that bypass occurs only in rare, unforeseen and unavoidable circumstances.

V. Emission Standards

a. Heat Inputs

As explained above in Part IV.b., an increase in hourly heat input rate increases pollutant emissions from the Units at the Plant, and effectively increases their lb/MMBtu emission limitations. It is important that these values not only be included in the permit, but also that they be made enforceable limits. Without an enforceable maximum hourly heat input limit, each Unit is unconstrained as to its maximum short-term emissions.

Maximum short-term pollutant emissions from the Plant can form the basis for air quality planning, i.e., an assessment of air quality impacts from this source, and establishing emissions limitations necessary to achieve and maintain compliance with air quality standards. A higher heat input may require more stringent lb/MMBtu emission limitations, control efficiency requirements or operational conditions in order to assure compliance with other air quality standards such as the new short-term one-hour NAAQS for NO_X and SO_2.

Finally, without enforceable maximum hourly heat input limits, the public and affected states have no opportunity to review and comment on a plant with a higher heat input (and thus higher actual emissions and effectively higher total emissions limitations) than what is identified in the Draft Permit. The rated heat inputs represented by GPC in its permit application and relied upon by EPD in issuing any permits for the Plant are applicable requirements (as are all data and assertions in the application) and must be stated as such and included in the permit as conditions that are subject to monitoring, record-keeping and reporting requirements adequate to demonstrate compliance.

b. Fuel Flexibility

The Draft Permit allows the Plant to burn almost any type of fuel, without regard to the pollutant characteristics of the fuels, and without limiting the percentage of non-coal fuels used. Although the Plant's steam-generating units "primarily burn coal," Draft Permit at 1, the permittee is permitted to blend the coal with sawdust and biomass, or fire used oil and coal-derived synthetic fuel. Draft Permit at 3-4. The Plant is also permitted to burn No. 2 fuel oil, biodiesel, or biodiesel blends for startup and shutdown, and "to assist in achieving peak load, and flame stabilization." Id. The addition to or replacement of coal with any of the other permitted fuels could significantly change the pollutant profile of this plant. Further, the fuel characteristics of different coals such as heat value and the content of pollutants such as mercury and sulfur also affect the type and quantity of pollutants emitted. Thus, the use of non-coal fuels must be more specifically defined and strictly limited in the final permit. The chemical characteristics of all permitted fuels, including coal, should be monitored and limited.

The only restrictions placed on the use of these alternative fuels are on coal-derived synthetic fuel, used oil and biomass. The Draft Permit limits the percentage the mercury and binder content of the coal-derive synthetic fuel, and the used oil may not be burned during startup or shutdown. However, there are no limits on the quantity or characteristics of any of these fuels, and no limits on fuel characteristics but for those on mercury and binder in coal-derived synthetic fuel. Further, the one meaningful limitation to the definition of "Biomass," municipal solid waste, still leaves a very broad range of materials that may fall under this term. As to the use of No. 2 fuel oil, biodiesel, and biodiesel blends, the operational conditions during which these fuels may be used are much too vaguely defined. Because the Draft Permit does not limit the maximum hourly heat input rate, allowing the burning or blending of various non-coal fuels could drastically affect the Plant's actual emissions, even when burning fuels that otherwise meet the permit's lb/MMBtu specifications.

The final permit should specifically limit the use of non-coal fuels, because the permit as drafted allows SC/GPC to switch fuels, which would significantly change the emissions contemplated by EPD in issuing this permit. EPD and GPC should perform a thorough and public analysis of the type and quantity of pollutants that may be emitted by all permitted fuels in all potential combinations. Fuel characteristics such as heat input, mercury content, and sulfur content should be limited and monitored. EPD should also require the permittee to monitor and report the types of fuels actually used at the Plant, including the quantities burned and the pollutant characteristics of each. The permit must also explain what is meant by "achieving peak load" and "flame stabilization" in terms that meaningfully limit when No. 2 fuel oil and biodiesels may be used. Startup and shutdown should also be more strictly defined, as described in Section VI below.

c. Particulate Matter

i. The PM Limit Should be Significantly Lowered

Particulate matter ("PM"), also called particle pollution, is a complex mixture of extremely small particles and liquid droplets in the air. When breathed in, these particles can reach the deepest regions of the lungs. Exposure to particle pollution is linked to a variety of significant health problems, ranging from aggravated asthma to premature death in people with heart and lung disease. Particle pollution is also the main cause of visibility impairment in the nation's cities and national parks.

The Draft Permit imposes a weak limit on PM emissions from the two steam-generating units of 0.24 lb/MMBtu. Draft Permit at 7, Condition 3.4.1. This lax PM limit derives from Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(d)1(iii), which applies to air emission units constructed or under construction prior to January 1, 1972. It is a grandfathering provision that gave older facilities like Plant Wansley a limit that is unreasonably high by modern standards under the assumption that those units were destined for retirement or would be updated with modern pollution controls.

As noted, Plant Wansley was required to install modern pollution controls by Rule (sss) – specifically, selective catalytic reduction and flue gas desulfurization. According to the Narrative, "GA Power proposes to designate the FGD scrubber as the primary control device to achieve compliance with the PM standard." Narrative at 26. During periods of scrubber bypass, emissions would be vented to the Plant's ESP device.

With these controls in place, the Draft Permit's PM limit is unreasonably lenient. As a comparison, the EPD assigned a rate of .012 lb/MMBtu for $PM_{2.5}$ to the proposed Longleaf facility, and the Draft Permit should include rates that are at least as stringent. Operational variability and the proper operation of the Plant's control devices can significantly affect PM and opacity emissions. Thus, a lower PM limit can lower actual emissions by forcing a facility to change the way it operates its pollution control equipment. The 0.24 lb/MMBtu limit gives the Plant an enormous compliance margin, and no incentive to operate its controls efficiently or otherwise minimize emissions.

ii. Coarse and Fine Particle Pollution Should be Limited and Monitored Separately

Currently, the Draft Permit inadequately regulates "particulate matter" or "PM" rather than regulate two different types of PM separately. The term "particulate matter," or "PM," includes two different types of pollutants: fine particle pollution, or $PM_{2.5}$, and coarse particle pollution, or PM_{10}. Both forms of PM have been linked to numerous deleterious health effects, including decreased lung function, aggravated asthma, chronic bronchitis, irregular heartbeat, heart attacks, and premature death. However, PM_{10} and $PM_{2.5}$ differ significantly, and separate NAAQS exist for each pollutant. Both PM_{10} and $PM_{2.5}$ should be clearly regulated in the Draft Permit.

PM_{10} and $PM_{2.5}$ are distinct air pollutants that do not share the same physical or behavioral characteristics. See, e.g., EPA, "Clean Air Fine Particle Implementation Rule" 72 Fed. Reg. 20586, 20599 (April 25, 2007) ("PM[2.5] also differs from PM[10] in terms of atmospheric dispersion characteristics, chemical composition, and contribution from regional transport."). PM_{10} and $PM_{2.5}$ pose different kinds and levels of risk to human health. Because of its extremely small size, $PM_{2.5}$ can penetrate deep into the lungs, enter the blood stream, and cross the blood-brain barrier. As a result, $PM_{2.5}$ pollution causes more frequent and severe adverse health effects than PM_{10}. EPA, "National Ambient Air Quality Standards for Particulate Matter," 62 Fed. Reg. 38652, 38665 (July 18, 1997). EPA has recognized a significant correlation between elevated $PM_{2.5}$ levels and premature mortality. See, e.g., EPA, "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)," 73 Fed. Reg. 28321, 28324 (May 16, 2008). Older adults, people with heart and lung disease, and children are particularly sensitive to $PM_{2.5}$ exposure. Id.

Finally, and most importantly, because of their different physical and behavioral characteristics, PM_{10} and $PM_{2.5}$ are not effectively treated with the same pollution controls. In fact, EPA has recognized that PM_{10} controls do not effectively control $PM_{2.5}$: "In contrast to PM[10], EPA anticipates that achieving the NAAQS for PM[2.5] will generally require States to evaluate different sources for controls, to consider controls of one or more precursors in addition to direct PM emissions, and to adopt different control strategies." 72 Fed. Reg. 20586, 20589; see also 62 Fed. Reg. at 38666.

EPA has confirmed that any technical impediments to the separate regulation of $PM_{2.5}$ have been resolved. 73 Fed. Reg. at 28340 ("With this final action [establishing NSR regulations for $PM_{2.5}$ and eliminating the PM_{10} Surrogacy Policy] and technical developments in the interim, these difficulties have largely been resolved."). Moreover, EPA announced in the final $PM_{2.5}$ implementation rule that for Title V permits, "as of the promulgation of this final rule, the EPA will no longer accept the use of PM_{10} emissions information as a surrogate for $PM_{2.5}$ emissions information given that both pollutants are regulated by a National Ambient Air Quality Standard and therefore are considered regulated air pollutants." Clean Air Fine Particle Implementation

Rule; Final Rule, 72 Fed. Reg. 20586, 20660 (April 25, 2007) (footnotes omitted). EPA explained its decision as follows:

> Under the Title V regulations, sources have an obligation to include in their Title V permit applications all emissions for which the source is major and all emissions of regulated air pollutants. The definition of regulated air pollutant in 40 CFR 70.2 includes any pollutant for which a NAAQS has been promulgated, which would include both PM[10] and PM[2.5]. To date, some permitted entities have been using PM[10] emissions as a surrogate for PM[2.5] emissions. Upon promulgation of this rule, EPA will no longer accept the use of PM[10] as a surrogate for PM[2.5]. Thus, ***sources will be required to include their PM[2.5] emissions in their Title V permit applications, in any corrections or supplements to these applications, and in applications submitted upon modification and renewal.*** *See* 40 CFR 70.5(c)(3)(i), 70.5(b), and 70.7(a)(1)(i); 40 CFR 71.5(c)(3)(i), 71.5(b), and 71.7(a)(1)(i).

Id. (emphasis added). The EPA has thus clearly stated that this Draft Permit is deficient and must be revised to include emission limits and monitoring specifically for $PM_{2.5}$.

d. Opacity

The Draft Permit specifies a 40 percent opacity limit measured over three-hour block averages for each of the Plant's main boilers. Draft Permit at condition 3.4. As with the lax PM limit, the 40 percent opacity limit is too high to ensure efficient operation of control devices and other operational practices that would minimize particulate emissions. It also fails to account for spikes in PM and opacity emissions resulting from operational variability. This extremely lenient opacity limitation must be strengthened to no more than 20 percent to assure proper operation and maintenance of the Plant's particulate controls, particularly during scrubber bypass.

e. The Draft Permit Should Contain Alternative Sections for CAIR and CSAPR Requirements

Currently, the Draft Permit contains provisions designed to comply with requirements under the Clean Air Interstate Rule ("CAIR"); however, the EPA has promulgated the final Cross-State Air Pollution Rule ("CSAPR") as a replacement to CAIR. Although CSAPR is currently stayed pending judicial review, it is likely that the provisions will be effective during the term of the permit. As a result, the draft permit should contain alternative conditions that will replace CAIR requirements and ensure compliance with CSAPR.

Specifically, the Draft Permit currently includes an annual NO_X allowance allocation for the Plant's units through 2013. Draft Permit at 43. However, if CSAPR survives judicial review, it will replace CAIR and all of its compliance requirements. It will impose an annual allowance trading program for SO_2 and NO_X to reduce transport of fine particulate matter and a separate ozone season NO_X allowance trading program to reduce ground-level ozone. CAIR annual and seasonal NO_X allowances will have no value for CSAPR compliance purposes, although the Acid Rain SO_2 program will continue as a separate program.

The final rule is structured as a Federal Implementation Plan ("FIP"). EPA has given Plant Wansley the following allocations under the final rule:

	SO_2 Allocation 2012 (tons)	SO_2 Allocation 2012 (tons)	NOx Annual Allocation 2012 (tons)	NOx Annual Allocation 2014 (tons)	NOx OS Allocation 2012 (tons)	NOx OS Allocation 2014 (tons)
1	10,672	6,389	4,036	2,606	757	757
2	10,276	6,152	3,887	2,509	776	776
5A	1	1	0	0	0	0
6A	3	3	58	58	32	32
6B	3	3	57	57	28	28
7A	3	3	67	67	49	49
7B	3	3	55	55	27	27
CT9A	1	1	57	57	23	23
CT9B	1	1	66	66	23	23

The above allocations give the facility both an SO_2 and an ozone season NO_X allocation, whereas the CAIR provisions of the Draft Permit provide allocations only for annual NO_X. <u>See</u> Draft Permit at 43.

To ensure that these limits are included within the Draft Permit, EPD should include a discussion of CSAPR provisions, alternative limitations and effective dates. Two suggestions would be to express such limits either as 7.15(a) (CAIR) and 7.15(b) (CSAPR); or to include an appendix of alternative emission limits to replace condition 7.15.

VI. Excess Emissions

The Draft Permit contains two conditions covering excess emissions: one covering emergencies (Condition 8.13) and the other covering excess emissions resulting from startup, shutdown or malfunction (Condition 8.14.4). The former is modeled virtually verbatim after 40 C.F.R. § 70.6(g) and therefore appears legally sufficient. The latter provision, however, is flawed in multiple ways and requires significant revision.

a. Condition 8.14.4 Should Not Include an Affirmative Defense

The Draft Permit exempts the Units from emissions limitations during periods of startup, shutdown, and malfunction. Condition 8.14.4 provides the facility with an affirmative defense against enforcement if it can meet certain showings – although unlike the condition governing excess emissions due to emergency (Condition 8.13), it does not use the term "affirmative defense" or even provide that the facility has the burden of establishing the criteria set out in subparagraphs (i) through (iii). Nevertheless, the condition functions like an affirmative defense provision because it allows the Permittee to escape enforcement under certain circumstances.

Specifically, it provides that "excess emissions resulting from startup, shutdown, or malfunction of any source which occur though ordinary diligence is employed **shall be allowed**" provided three criteria are met, namely that:

i. The best operational practices to minimize emissions are adhered to;

ii. All associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions; and

iii. The duration of excess emissions is minimized.

In contrast, "[e]xcess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may be reasonably be prevented during startup, shutdown or malfunction are prohibited and are violations of Chapter 391-3-1 of the Georgia Rules for Air Quality Control."

EPA has issued several guidance documents regarding excess emissions provisions.[6] EPA has repeatedly stressed that where a single source has the potential to cause an exceedance of the NAAQS or PSD increments – as the agency has noted is often the case with SO_2 emissions from coal-fired units like those at the Plant – preordaining an affirmative defense is not sufficient to protect public health and the environment. In such circumstances, EPA has stated that the only appropriate means of dealing with excess emissions during malfunction, startup and shutdown episodes is by responsibly exercising enforcement discretion rather than by prospectively establishing a blanket exemption.

Even though Condition 8.14.4 tracks the language of the state rule verbatim, and the state rule has been approved as part of the SIP, EPD is not obligated to include such language in the Draft Permit and must not do so for Plant Wansley. For the reasons noted by EPA, Plant Wansley is not the type of facility that can be afforded the benefit of an affirmative defense for excess emissions occurring during startup, shutdown or malfunction. Instead, an enforcement discretion approach is warranted, whereby EPD can refrain, on a case-by-case basis, from imposing penalties for sudden and unavoidable malfunctions caused by circumstances entirely beyond the control of the owner or operator. For this reason, Condition 8.14.4 must be stricken from the Draft Permit. Any excess emissions that occur due to startup, shutdown or malfunction, and which are alleged by the source to have been unavoidable, must be handled through an enforcement discretion approach.

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[6] See generally EPA memo entitled, "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown," by Steven A. Herman dated September 20, 1999; EPA Memo entitled "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions," by Kathleen M. Bennett dated February 15, 1983; EPA memo entitled "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions," by Kathleen M. Bennett, dated September 28, 1982.

b. If an Affirmative Defense is Retained, It Must be Revised to State that All Excess Emissions Are Violations and to Retain the Availability of Injunctive Relief

EPA has repeatedly made it clear that because excess emissions can aggravate air quality so as to prevent attainment or interfere with maintenance of the ambient air quality standards, it views **all** excess emissions as violations of the applicable emissions limitation. While EPA has recognized that the state or EPA can exercise "enforcement discretion" to refrain from taking enforcement action where the excess emissions result from sudden and unavoidable malfunctions caused by circumstances entirely beyond the owner or operator's control, the excess emissions remain violations subject to enforcement action. The state can excuse the source from penalties if the source can demonstrate that it meets certain objective criteria; however, the state cannot provide that the excess emissions are not violations. Moreover, the state cannot exempt the source from actions for injunctive relief.

As currently written, Condition 8.14.4 violates both prohibitions. It declares that excess emissions "shall be allowed" – i.e., are not violations – provided that the criteria in subparagraphs (i), (ii) and (iii) of paragraph (a) are met. This is improper, as EPA has made it clear that all excess emissions are violations of the applicable emission limitation, and must be treated as such even in those circumstances where it is appropriate to allow a source an opportunity to present an affirmative defense.

In addition, Condition 8.14.4 appears to improperly preclude injunctive relief. In declaring that under certain circumstances excess emissions from startup, shutdown, or malfunction "shall be allowed," the condition makes no distinction between penalties and injunctive relief: any and all available remedies appear to be precluded. EPA has made it clear that an acceptable affirmative defense provision may only apply to actions for penalties but not to actions for injunctive relief. However, by failing to make any distinction between actions for civil penalties and actions for injunctive relief, Condition 8.14.4 improperly provides a defense against the latter form of enforcement action. This is an inappropriate barrier to enforcement by citizens or EPA.

Therefore, if Condition 8.14.4 is retained in the Permit, it must be revised to state that any excess emissions due to startup, shutdown and malfunction are violations of the Georgia Air Quality Act and federal Clean Air Act. Further, it must be revised to state that any affirmative defense provisions apply only to actions for penalties and not to actions for injunctive relief.

c. If an Affirmative Defense is Retained, It Must Be Revised to Provide Objective Criteria that Will Allow for Practical Enforceability

i. Vague and Undefined Terms Must Be Replaced with Specific and Objective Operational Requirements

The Clean Air Act expressly defines the term "emission limitation" as a limitation on emissions of air pollutants "on a continuous basis." 42 U.S.C. § 7602(k). For affirmative defense for excess emissions occurring during startup, shutdown or malfunction to be valid, the permitting authority must demonstrate that any exemptions from emission limitations are unavoidable and ensure that such exemptions are minimized. To establish a work practice standard as an alternative limit during exempt 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. See, e.g., 40 C.F.R. § 51.166(b)(12) (limiting the exemption from BACT emissions limits for startup, shutdown and malfunction). EPD has done no such analysis to justify the exemptions contained in the permit.

In addition, EPD has also failed to provide specific and limiting definitions for the terms "startup," "shutdown" and "malfunctions" so the limitations apply during these periods only when "the imposition of an emissions standard [is] infeasible."

Of the three referenced periods, "startup" is the only term that is defined anywhere in the Draft Permit: "for purposes of" the Draft Permit, startup is defined as "the period lasting from the time the first oil fire is established in the furnace until the time the mill/burner performance and secondary air temperature are adequate to maintain an exit gas temperature above the sulfuric acid dew point." Draft Permit at 4, Condition 3.2.2.

However, the terms shutdown and malfunction are not defined within the permit, and there does not seem to be a referenced definition that provides a limitation to these periods. Although condition 8.1.1 of the Draft Permit states that "[t]erms not otherwise defined in the Permit shall have the meaning assigned to such terms in the referenced regulation," the regulation referenced by Condition 8.14.4 – Georgia Rule 391-3-1-.02(2)(a)7 – does not define the terms shutdown and malfunction. The terms are instead defined in the definitions section of the Georgia Air Quality Rules. See Rule 391-3-1-.01 at (nn), & (jjj). However, the definitions of shutdown and malfunction provided there are no more specific than the dictionary definitions of those terms,[7] and thus do not provide any meaningful limits on these exempt periods. In order to ensure that the exemptions only apply when necessary, the final permit should specifically and

[7] "'[M]alfunction' means mechanical and/or electrical failure of a process, or of air pollution control process or equipment, resulting in operation in an abnormal or unusual manner," Rule 391-3-1-.01(nn), "'shutdown' means the cessation of the operation of a source or facility for any purpose," Rule 391-3-1-.01(jjj), and "'startup' means the commencement of operation of any source." Rule 391-3-1-.01(zzz).

strictly limit the meaning of all these terms so that the periods of exemption do not swallow the emissions limitations.

In lieu of providing these specific definitions or setting numeric limitations that otherwise would apply, the Draft Permit requires the Plant to "minimize" the duration of these exempt periods, and to observe "best operational practices" and "good air pollution control practice." Draft Permit at 51. Neither Condition 8.14.4 nor the Draft Permit defines the phrases "best operational practices" and "good air pollution control practice." This omission impermissibly undermines the enforceability of these requirements.

The final permit should translate the terms "best operational practices" and "good air pollution control practice" into specific and objective operational conditions to ensure that they are practicably enforceable. As EPA has stated, "[s]tart-up and shutdown events are part of the normal operation of a source and should be accounted for in the design and implementation of the operating procedure for process control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods." Kathleen M. Bennett, EPA, "Policy on Excess Emissions During Startup, Shutdown, Maintenance and Malfunction" (Sept. 28, 1992). Similarly, prudent planning and design can also help minimize emissions during periods of malfunction. Standard permit conditions for coal-fired electric generating units include particular Best Management Practices as a safeguard to minimize emissions during limitation exemptions for startup, shutdown, and malfunction. To avoid emissions during these periods, operators should be required to continuously monitor boiler conditions, oxygen levels, soot blowers, trouble alarms, precipitator hopper levels, and other monitoring safeguards. The final permit should require that the amount, and not just the duration, of emissions be minimized and include qualifying language such as "at all times" and "to the maximum extent practicable," that would allow for meaningful enforcement. Further, it must require contemporaneous recordkeeping to document the owner or operator's actions during the periods of startup, shutdown or malfunction.

ii. The Permit Must Include Separate Criteria for Malfunctions

As currently written, Condition 8.14.4 fails to acknowledge any distinction between, on the one hand, startup and shutdown, and on the other, malfunction events. All such episodes are treated alike: if it can be shown, presumably by SC/GPC, that (1) best operational practices to minimize emissions were adhered to; (2) pollution control equipment was operated consistent with good air pollution control practices for minimizing emissions; and (3) the duration of excess emissions was minimized, then the source can escape any liability for the excess emissions. This is improper. As EPA has noted, startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation of the operating procedures for the process and control equipment. For this reason, EPA has stated that it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods. See Kathleen M. Bennett, EPA, "Policy on Excess Emissions

During Startup, Shutdown, Maintenance, and Malfunctions" (Sept. 28, 1982). In contrast, if properly defined and limited, a malfunction – whether it occurs during or outside of a startup or shutdown – can be the type of sudden and unavoidable event that produces excess emissions despite the facility's best efforts.

Excess emissions during startup or shutdown can be the result of a malfunction; in such cases, the malfunction should be handled as any other malfunction. However, where there is no alleged malfunction, excess emissions occurring during startup or shutdown must be treated differently because they very likely could have been avoided. As EPA has stated, "[a]ny activity or event which can be foreseen and avoided, or planned, falls outside of the definition of sudden and unavoidable breakdown of equipment." Kathleen M. Bennett, EPA, "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions," (Feb. 15, 1983).

For these reasons, any affirmative defense provision in Condition 8.14.4 must apply different criteria to alleged malfunctions than it does to startup and shutdown. See Steven A. Herman, EPA, "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown" (Sept. 20, 1999). If the permit provides an affirmative defense for malfunctions, it must provide that the Permittee has the burden of proof of demonstrating that:

1. The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator;
2. That the excess emissions (a) did not stem from any activity or event that could have been foreseen or avoided, or planned for, and (b) could not have been avoided by better operation and maintenance practices;
3. To the maximum extent practicable the air pollution control equipment or processes were maintained and operated in a manner consistent with good practices for minimizing emissions;
4. Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded. Off-shift labor and overtime must have been utilized, to the extent practicable, to ensure that such repairs were made as expeditiously as practicable;
5. The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;
6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;
7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence;
9. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and
10. The owner or operator properly and promptly notified EPD.

For excess emissions occurring during routine startup or shutdown, the provision should state that the permittee has the burden of proof to demonstrate that:

1. The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;
2. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;
3. If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable due to an emergency, as per Condition 8.13;
4. At all times, the facility was operated in a manner consistent with good practice for minimizing emissions;
5. The frequency and duration of operation in startup or shutdown mode was minimized to the maximum extent practicable;
6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;
7. All emission monitoring systems were kept in operation if at all possible;
8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and
9. The owner or operator properly and promptly notified the appropriate regulatory authority.

Finally, the provision should make it clear that if excess emissions occur during routine startup or shutdown periods due to malfunction, then such instances will be treated the same as other malfunctions.

d. Condition 8.14.4 Must Be Revised to Address National Emissions Standards for Hazardous Air Pollutants

As currently written, paragraph (c) states that the provisions of Condition 8.14.4 do not apply to sources subject to New Source Performance Standards. This paragraph must be rewritten to make it clear that the affirmative defense provision does not apply to any federally promulgated performance standards or emission limits, including not just new source performance standards but also national emissions standards for hazardous air pollutants ("NESHAPS"). See Steven A. Herman, EPA, "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown" (Sept. 20, 1999). As EPD is aware, EPA issued a NESHAP for utility boilers that became final and effective on December 16, 2011, and thus is applicable to this Draft Permit. See below Part X.

VII. Compliance Assurance Monitoring and Reporting

EPA's Part 70 monitoring rules (40 C.F.R. §§ 70.6(a)(3)(i)(A)-(B), (c)(1)) are designed to satisfy the statutory requirement in section 504(c) of the Act that "[e]ach permit issued under [Title V] shall set forth . . . monitoring . . . requirements to assure compliance with the permit terms and conditions." 42 U.S.C. § 7661c(c). Permitting authorities must take three steps to satisfy the monitoring requirements in the Part 70 regulations. First, under 40 C.F.R. § 70.6(a)(3)(i)(A), permitting authorities must ensure that Title V permits contain all applicable monitoring requirements. Second, if an applicable CAA requirement contains no periodic monitoring, permitting authorities must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B). Third, if there is some periodic monitoring in the applicable requirement, but that monitoring is not sufficient to assure compliance with permit terms and conditions, permitting authorities must supplement monitoring to assure such compliance. 40 C.F.R. § 70.6(c)(1). In all cases, the rationale for the selected monitoring requirements must be clear and documented in the permit record. See 40 C.F.R. § 70.7(a)(5); Ga. Comp. R. & Regs. r. 391-3-1-.03(10)(a)(2) (requiring that Title V permits "assure compliance with all applicable requirements"), and (d)(1) (incorporating 40 C.F.R. Part 70.6(a) and 40 C.F.R. 70.7(f)).

a. Particulate Matter and Opacity

i. The Frequency of PM Testing Must Be Increased

Compliance with the facility's PM limit is demonstrated via stack tests. For the Steam Generating Units 1 and 2 scrubber bypass stacks, the tests will be conducted the first of 30 days following 8760 operating hours or 60 months for the unit. Draft Permit at 14, Condition 4.2.1a. For the combined scrubber stack, testing is required every 60 months, or once per permit term. Id. at Condition 4.2.1b. As a result, the Plant may only conduct combined stack testing for PM emissions once every five years.

The expected operational variability of these units can significantly affect ESP and scrubber control efficiency and thus, resulting emissions. Federal regulations make clear that monitoring and reporting requirements must, to the extent possible, match the time period over which an emission limitation is measured. The Draft Permit's infrequent and intermittent compliance testing requirements will not assure or demonstrate compliance with PM limitations, which are applicable on a continuous basis. Nor will they adequately address this facility's contribution to NAAQS violations that are based on one-hour averages.

The Draft Permit should be revised to mandate the installation and use of a continuous emissions monitoring system ("CEMS") for PM in lieu of the requirements of draft condition 4.2.1. PM_{10} CEMS are common and have been readily available on a commercial scale for many years. EPA, Current Knowledge of Particulate Matter (PM) Continuous Emissions Monitoring (Sept. 2000), available at http://www.epa.gov/ttnemc01/cem/pmcemsknowfinalrep.pdf. PM CEMS should be installed "to assure compliance with the permit terms and conditions" as required by Title V of the Clean Air Act. 42 U.S.C. § 7661c(c).

ii. Parametric Monitoring is Inadequate to Assure Compliance

Because the units lack PM CEMS, it is critical that stack testing be accompanied by rigorous parametric monitoring to ensure that the periodic stack tests are representative of normal operations. Parametric monitoring is also critical to control emissions of $PM_{2.5}$, for which CEMS do not exist.

The Draft Permit mandates the use of continuous opacity monitoring systems ("COMS") for both steam-generating units during bypass, Condition 5.2.1. According to the Narrative, during scrubber bypass, only the Units' ESP devices will control PM emissions. Narrative at 26. Given the Draft Permit's lax opacity limit, additional parameters should be considered, including proper voltages in the charging and collection portions of the ESPs, proper gas conditioning requirements to ensure that particle resistivity remains within acceptable ranges, and flow indicators that ensure there is no gas flow mal-distribution into the ESPs.

b. SO_2

i. The Draft Permit's SO_2 Monitoring and Compliance Provisions Must be Revised to be Consistent with the 1-hr SO_2 NAAQS

On June 2, 2010, the EPA finalized a one-hour primary NAAQS for SO_2. The final standard, which was set at 75 parts per billion ("ppb"), replaces two primary standards of 140 ppb, measured over 24 hours, and 30 ppb, measured over one year. In revising the limit to a one-hour standard, EPA cited significant health benefits, particularly for at-risk populations. SO_2 is a known precursor of fine particle pollution.

The Draft Permit's sole SO_2 limit is the one derived from Rule (uuu). The facility may not discharge into the atmosphere from any of its Units "any gases which contain SO_2 emissions in excess of 5 percent (0.05) of the potential combustion concentration on a 30-day rolling average basis." Draft Permit at 9, Condition 3.4.13. As noted previously, the facility is relieved of this obligation during periods of startup, shutdown, and malfunction, as well as during other periods specified in Condition 3.4.14. Id.

Compliance with the 95 percent reduction mandate of Condition 3.4.13 is to be demonstrated via initial and subsequent performance tests. Condition 4.2.2.a. An "initial performance test" was completed as of the first 30 successive boiler operating days following

January 1, 2010. After the initial performance demonstration, the Draft Permit requires a separate performance test at the end of each operating day and the calculation of a new 30-day percent reduction calculated to demonstrate compliance. Id. The Draft Permit does not specify what constitutes a "performance test" for purposes of this provision; presumably the demonstration is made via SO_2 CEMS.

Condition 5.2.1 requires that CEMS be installed and operated on Steam Generating Units 1 and 2 at the combined inlet and outlet of the wet scrubber. Draft Permit at 15, Condition 5.2.1.c.

The Draft Permit requires calculation and reporting of a 30-day rolling average emission rate. Draft Permit at 32, Conditions 6.1.15. and 6.2.16. Although the Draft Permit also requires calculation of 1-hour averages, Condition 5.2.15, it does not appear to require reporting on an hourly basis.

The Draft Permit's SO_2 monitoring and compliance provisions are insufficient in light of the one-hour SO_2 NAAQS. Because the Draft Permit requires CEMS, there is no technical obstacle to requiring the facility to monitor and report its SO_2 emissions on an hourly basis. Unless such revisions are made, the final permit will lack an SO_2 limit that is designed to achieve and maintain the SO_2 NAAQS, and will lack a compliance provision designed to show that the limit is being met over the same averaging period as the prevailing air quality standard.

ii. The Permit's Terms are Inconsistent with Regard to Control Devises Needed for Compliance with Rule (uuu) on a Unit-Specific Basis

The Draft Permit is unclear as to whether EPD requires the Plant to install and operate one or two CEMS to monitor SO_2 emissions. Compare Page 3 (listing two FGD scrubbers for two separate lines of exhaust) with page 15 ("Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device."). This should be clarified within the draft permit by changing the language on page 15 to say "Sulfur dioxide emissions are monitored at both the inlet and the outlet of each SO_2 control device."

iii. The Permit Should Clearly Require SO_2 CEMS Operation During All Periods of Operation except CEMS Breakdown and Repair

The Draft Permit properly requires that SO_2 CEMS for the bypass stacks be operated during all periods of operation, including periods of startup, shutdown, malfunction or emergency. Draft Permit at 21, Condition 5.2.14. While the permit appears to give limited exceptions for "CEMS breakdowns, repairs, calibration checks, and zero and span adjustments," condition 5.2.14 also exempts a broad range of periods through the statement "and any period allowed under Georgia Rule 391-3-1-.02(2)(uuu)(4)." This regulation exempts the Plant's units from the 95% SO_2 reduction requirements during periods of "black starts" and scheduled or preventive maintenance as well as during periods of startup, shutdown or malfunction provided such episodes are consistent with the air quality rule governing allowable "excess emissions," Rule 391-3-1-.02(2)(a)7. Draft Permit at 21.

Thus, while appearing at first blush to require the operation of SO_2 CEMS during periods of startup, shutdown, or malfunction, the Draft Permit appears ultimately to eliminate any such requirement for normal operation – i.e., when both units are exhausting through the wet scrubber(s). Draft Permit at 1, 3.

The CEMS data are used to demonstrate compliance with the permit's SO_2 limit under Rule (uuu). See Draft Permit at 21, Conditions 5.2.14. Under CAA Section 302(k), an emission limitation is one that "limits the quantity, rate, or concentration of emissions of air pollutants **on a continuous basis**, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction. . . ." The permit's SO_2 emissions limitation is meaningful and enforceable only to the extent that compliance with it can be demonstrated on a continuous basis. A clear requirement to operate SO_2 CEMS during all periods except CEMS breakdown and repair is necessary to "assure compliance with the terms and conditions of the permit." 40 C.F.R. § 70.6(c)(1).

VIII. Coal Handling System

The Draft Permit does not include or meet regulatory requirements for fugitive emissions from solid fuel handling systems. Fuel handling systems, particularly those for coal-fired power plants such as this Plant, can release significant amounts of PM into the air near the facility. These emissions are at ground level, heightening their impact on air quality and human health in the immediate vicinity of the Plant.

Georgia regulations include a non-exhaustive list of specific control devices and practices that should be applied to this facility and detailed in its Title V permit as enforceable conditions of its operation. These include the application of water or other dust suppressants on surfaces or operations that can give rise to airborne dust, and "[i]nstallation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials." Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n)1. The Draft Permit subjects the coal handling system to an opacity limit of 20 percent as required by Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n)2, but does not include the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust from this component of the plant. Draft Permit at 7. Rather, the Permittee is required to take "reasonable precautions." Id. This requirement is vague and unenforceable.

Specific work practice standards can and should be applied to this major PM emissions source and made enforceable in its Title V permit. The permit provisions covering the solid fuel handling system should specify and require the "reasonable precautions" appropriate to this facility. The permit should include enforceable conditions requiring enclosures and other control devices that are demonstrated to eliminate PM emissions from the fuel handling system. These devices should be described in more detail in the permit or narrative, and should be subject to monitoring and reporting to demonstrate compliance with a 20 percent opacity limit, so that the public can evaluate their efficacy and, when necessary, seek enforcement of any violations. The required frequency, quantity and duration of dust suppression techniques should also be included in the Draft Permit.

IX. Greenhouse Gas Monitoring and Reporting

As described above, Title V permits must include "all applicable requirements" that will exist during the permit term. Greenhouse gas monitoring and reporting requirements were promulgated on October 30, 2009 and amended on July 12, 2010. 40 C.F.R. § 98. However, the Draft Permit does not identify these requirements as applicable to Plant Wansley. EPA Guidance specifically addresses how greenhouse gases are to be handled under Title V of the Clean Air Act and its Amendments, stating that "as with other applicable requirements related to non-GHG pollutants, any applicable requirement for GHGs must be addressed in the title V permit (*i.e.*, the permit must contain conditions necessary to assure compliance with applicable requirements for GHGs)." U.S. EPA, Office of Air and Radiation, "PSD And Title V Permitting Guidance For Greenhouse Gases" at 52 (March 2011), available at http://www.epa.gov/region07/air/title5/t5memos/ghgguid.pdf (last accessed May 18, 2012). EPD must include conditions in Part 2.0, Part 3.0, Part 5.0 and Part 6.0 of the permit specifying the recordkeeping and monitoring requirements of 40 CFR §§ 98.43, 98.44, and 98.47.

X. Hazardous Air Pollutants

As noted supra, CAA 504(a) requires each Title V permit to "assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan [SIP]." 40 C.F.R. § 70.2 defines "applicable requirements" as including "requirements that have been promulgated or approved by EPA through rulemaking at the time of issuance but have future effective compliance dates."

As the Narrative points out, Plant Wansley is potentially subject to 40 C.F.R. 63, Subpart UUUUU, which the Narrative suggests had not been formally promulgated as of the time of the Draft Permit. Narrative at 14. However, the EPA did promulgate this final rule, titled "National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," on February 12, 2012. 77 Fed. Reg. 9304.

This rule works to reduce emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF) by regulating "coal fired electric utility steam generating units." Id. Although this rule went into effect on April 16, 2012, it will be applicable to Plant Wansley on April 16, 2015, during the Title V permit term. Thus, the draft permit should include both an acknowledgement that the Plant is subject to this new regulation, as well as provisions reflecting the emissions standards required under this rule.

We thank you for the opportunity to submit these comments. We look forward to receiving the Department's response to our comments and to receiving notice of the Department's final permit decisions.

Respectfully submitted,

Ashten Leigh Bailey

Ashten Bailey
Staff Attorney
GreenLaw

EXHIBIT C

Facility Name: **Wansley Steam – Electric Generating Plant**
City: Carrollton
County: Heard
AIRS #: 04-13-149-00001

Application #: TV-20541
Date Application Received: June 29, 2011
Permit No: 4911-149-0001-V-03-0

Program	Review Engineers	Review Managers
SSPP	Anna C. Aponte	Furqan Shaikh
ISMP	Dave Sheffield	DeAnna Oser
SSCP	Pierre Sanon	James Eason
Toxics		Michael Odom
Permitting Program Manager		Eric Cornwell

Introduction

This narrative is being provided to assist the reader in understanding the content of the attached draft Part 70 operating permit. Complex issues and unusual items are explained here in simpler terms and/or greater detail than is sometimes possible in the actual permit. This permit is being issued pursuant to: (1) Georgia Air Quality Act, O.C.G.A § 12-9-1, et seq. and (2) Georgia Rules for Air Quality Control, Chapter 391-3-1, and (3) Title V of the Clean Air Act. Section 391-3-1-.03(10) of the Georgia Rules for Air Quality Control incorporates requirements of Part 70 of Title 40 of the Code of Federal Regulations promulgated pursuant to the Federal Clean Air Act. The primary purpose of this permit is to consolidate and identify existing state and federal air requirements applicable to **Wansley Steam – Electric Generating Plant** and to provide practical methods for determining compliance with these requirements. The following narrative is designed to accompany the draft permit and is presented in the same general order as the permit. It initially describes the facility receiving the permit, the applicable requirements and their significance, and the methods for determining compliance with those applicable requirements. This narrative is intended as an adjunct for the reviewer and to provide information only. It has no legal standing. Any revisions made to the permit in response to comments received during the public participation and EPA review process will be described in an addendum to this narrative.

I. Facility Description

A. Facility Identification

1. Facility Name:

   Wansley Steam – Electric Generating Plant

2. Parent/Holding Company Name

   The Southern Company
   Georgia Power Company

3. Previous and/or Other Name(s)

   This facility is commonly known and referred to as Plant Wansley. No other names were identified.

4. Facility Location

   1371 Liberty Church Road
   Carrollton, GA 30116, Heard County

5. Attainment, Non-attainment Area Location, or Contributing Area

   Heard County is currently in attainment for ozone but designated as a contributing county with enhanced monitoring and is located in a $PM_{2.5}$ non-attainment area.

B. Site Determination

Plant Wansley is currently contracting with an ash processing facility located on site to process and sell some of the coal ash produced from the electric generating process at Plant Wansley. Even though the ash processing facility and Plant Wansley are located on contiguous property, they are deemed to be separate sources for purposes of Title V permitting due to the fact that there is no common control between Georgia Power Company and the ash processing facility. Therefore, the Title V permit for Plant Wansley covers only those operations controlled solely by Georgia Power. The ash processing facility, which is itself a minor source under 40 CFR Part 70, will continue to operate under its minor source SIP permit.

The Wansley Steam-Electric Generating Plant (AFS No. 149-00001), Southern Power - Wansley Combined-Cycle Generating Plant (AFS No. 149-00011), Oglethorpe Power Corporation – Chattahoochee Energy Facility (AFS No. 149-00006), and the Municipal Electric Authority of Georgia – Wansley Unit 9 (AFS No. 149-00007) are permitted separately. Collectively, they comprise the same Title V site. However, each separate owner/operator is only accountable, for compliance purposes, for the individual electrical generating units that they own or operate.

C. Existing Permits

Table 1 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a comparative review of form A.6, Current Permits, of the Title V application and the "Permit" file(s) on the facility found in the Air Branch office.

Table 1: List of Current Permits, Amendments, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-149-0001-V-02-0	December 20, 2006	Title V Renewal Permit
4911-149-0001-V-02-1	March 7, 2007	Incorporate changes to Georgia Rule 391-3-1-.02(2)(jjj)
4911-149-0001-V-02-2	August 21, 2007	Revise language for Conditions 5.2.1(d), 6.1.7(c)(iii), and 8.17.2
4911-149-0001-V-02-3	October 30, 2008	Allow the use of method ASTM D5142 or ASTM D3173 to analyze coal samples for moisture content, add the compliance dates for Wansley according to the Georgia Multipollutant Rule 391-3-1-.02(2)(sss), and allow the use of Part 75 Appendices A and B as an alternative to complying with Sections 4, 5, and 6 of 40 CFR 60, Appendix F for consistency with appropriate procedures for low emitting NOx monitoring.
4911-149-0001-V-02-4	November 25, 2008	Include method ASTM D1522 to determine No. 2 fuel oil sulfur content in Condition 6.2.3, include Methods D4629 and D3228 to determine No. 2 fuel oil nitrogen content in Condition 4.1.3.o, and update street address and plant contact information.
4911-149-0001-V-02-5	March 12, 2009	Update the Title IV Acid Rain Program Phase II NO_X averaging plan.
4911-149-0001-V-02-6	September 17, 2009	Incorporate Clean Air Interstate Rule (CAIR).
4911-149-0001-V-02-7	November 18, 2009	Incorporate changes to Georgia Rule 391-3-1-.02(2)(sss); Reduce the frequency of particulate matter testing in Condition 4.2.1 due to changes in operation associated with the scrubber installations; Add the monitoring of sparger submergence level in the scrubber; Add the excursion level definition in Condition 6.1.7; Revise the monitoring requirements for the affected Materials Handling System in Condition 5.2.20
4911-149-0001-V-02-8	November 30, 2010	Incorporate Georgia rule (uuu) requirements for Steam Generating Units 1 and 2 (Emission Unit IDs: SG01 and SG02). Update the visible emissions requirements for the Materials Handling System (Emission Unit ID: MHS).
4911-149-0001-V-02-9	Pending	Revise the periodic reporting deadlines in Condition Nos. 6.1.3, 6.1.4, 6.2.13, 6.2.22, 6.2.27, and 8.14.1.

D. Process Description

1. SIC Codes(s)

4911

The SIC Code(s) identified above were assigned by EPD's Air Protection Branch for purposes pursuant to the Georgia Air Quality Act and related administrative purposes only and are not intended to be used for any other purpose. Assignment of SIC Codes by EPD's Air Protection Branch for these purposes does not prohibit the facility from using these or different SIC Codes for other regulatory and non-regulatory purposes.

Should the reference(s) to SIC Code(s) in any narratives or narrative addendum previously issued for the Title V permit for this facility conflict with the revised language herein, the language herein shall control; provided, however, language in previously issued narratives that does not expressly reference SIC Code(s) shall not be affected.

2. Description of Product(s)

Plant Wansley burns fossil fuel to generate electricity.

3. Overall Facility Process Description

This facility includes two steam electric generating units which primarily burn coal and one simple cycle combustion turbine which burns No. 2 fuel oil. Each steam generating unit exhausts through its own stack liner in the 1000-ft stack. The combustion turbine has its own exhaust which is 32-ft tall.

Southern Power owns the two combustion turbine combined-cycle blocks. All of the applicable permit conditions have been moved to Title V Permit 4911-149-0011-V-01-0.

4. Overall Process Flow Diagram

The facility provided a process flow diagram in their Title V permit application.

E. Regulatory Status

1. PSD/NSR

Note: The Georgia Power Company - Wansley Steam-Electric Generating Plant (Plant Wansley , AFS No. 149-00001), Southern Power - Wansley Combined-Cycle Generating Plant (AFS No. 149-00011), Oglethorpe Power Company-Wansley Combined-Cycle Energy Facility (AFS No. 149-00006), and the Municipal Electric Authority of Georgia-Wansley Unit 9 (MEAG Power, AFS No. 149-00007) comprise the same Title I (PSD/NSR) and Title V site because the plants are located on contiguous property, operate under common control, and have the same two digit SIC code.

This Title I site is a major source under PSD because it has potential emissions of particulate matter, SO_2, NOx, VOC, and CO greater than 100 tpy (it is one of the 28 named source categories under PSD). Portions of this Title I site were originally constructed before the PSD regulations were effective.

2. Title V Major Source Status by Pollutant

Table 2: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	✓	✓		
PM_{10}	✓	✓		
SO_2	✓	✓		
VOC	✓	✓		
NO_x	✓	✓		
CO	✓	✓		
TRS	N/a			✓
H_2S	N/a			✓
Individual HAP	✓	✓		
Total HAPs	✓	✓		

3. MACT Standards

This facility is major for HAPs. The steam generating units are not subject to 40 CFR 63, Subpart DDDDD "Industrial, Commercial and Institutional Boilers and Process Heaters" because while Plant Wansley contains boilers, the units are all electric utility steam generating boilers that generate steam to produce electricity for sale. Plant Wansley does have two start-up boilers that could potentially be classified as limited use and only subject to the initial notification requirements.

The combustion turbine (Emission Unit CT5) is subject to 40 CFR 63 Subpart YYYY - National Emission Standard for Hazardous Air Pollutants: Stationary Combustion Turbines. Since the affected unit is an existing stationary combustion turbine, it does not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for an existing stationary combustion turbine.

40 CFR 63, Subpart UUUUU: National Emission Standards for Hazardous Air Pollutants from Coal and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units was finalized on December 16, 2011 but has not been formally promulgated. This rule will become effective on April 16, 2012.

4. Program Applicability (AIRS Program Codes)

Program Code	Applicable (y/n)
Program Code 6 - PSD	Yes
Program Code 8 – Part 61 NESHAP	No
Program Code 9 - NSPS	Yes
Program Code M – Part 63 NESHAP	Yes
Program Code V – Title V	Yes

Regulatory Analysis

II. Facility Wide Requirements

A. Emission and Operating Caps:

None applicable.

B. Applicable Rules and Regulations

None applicable.

C. Compliance Status

The facility is operating in compliance with their air quality permit.

D. Operational Flexibility

None applicable.

E. Permit Conditions

None applicable.

III. Regulated Equipment Requirements

A. Brief Process Description

This facility includes two, primarily coal-fired, steam generating units and one, No. 2 fuel oil-fired, simple cycle combustion turbine. The following table includes more detailed information on each unit.

Emission Unit ID	Emission Unit Description	Max Heat Input Capacity (MMBtu/hr)	Fuel Burning Configuration
SG01	Steam Generating Unit 1	9420	Tangentially-fired
SG02	Steam Generating Unit 2	9420	Tangentially-fired
CT5A	Combustion Turbine Unit 5A	904	Normal combustor with water injection

In September 2000, the facility installed Selective Catalytic Reduction (SCR) systems on the steam generating units SG01 and SG02. This resulted in a reduction of NOx emissions in excess of 7,900 tons.

In January 2006, the facility received authorization to construct and operate a wet limestone Flue Gas Desulfurization (FGD) scrubber to be installed on Steam Generating Units 1 and 2 (Emission Units SG01 and SG02) to remove SO_2 from the units' flue gas emission stream. The scrubbers utilize limestone to capture SO_2 and convert it to gypsum. Also, the Materials Handling System (MHS) includes limestone and gypsum and is composed of storage piles, conveyors, bunkers, transfer stations, crushing operations and loading/unloading operations. This resulted in a reduction of SO_2 emissions in excess of 167,329 tons and PM emissions in excess of 1,630 tons.

B. Equipment List for the Process

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
SG01	Steam Generator Unit 1	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu), and Acid Rain	3.2.1, 3.2.2, 3.2.6, 3.4.1, 3.4.2, 3.4.3, 3.4.7, 3.4.8, 3.4.9, 3.4.10, 3.4.13, 3.4.14, 3.4.15	EP01 SCR1 FGD1	ESP SCR FGD
SG02	Steam Generator Unit 2	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu), and Acid Rain	See SG01	EP02 SCR2 FGD2	ESP SCR FGD
CT5A	Combustion Turbine Unit 5A	40 CFR 60 Subpart A 40 CFR 60 Subpart GG 391-3-1-.02(2)(b) and (g) 391-3-1-.02(2)(nnn)(7) 40 CFR 63 Subpart YYYY	3.2.3, 3.2.5, 3.3.1, 3.3.2, 3.3.3, 3.4.2, 3.4.11	WI5A	Water Injection
SB01	Start-up Boiler Unit 1	391-3-1-.02(2)(b), (d), and (g) 40 CFR 63 Subpart A 40 CFR 63 Subpart DDDDD	3.2.4, 3.3.5, 3.4.2, 3.4.3, 3.4.4	none	n/a
SB02	Start-up Boiler Unit 2	391-3-1-.02(2)(b), (d), and (g) 40 CFR 63 Subpart A 40 CFR 63 Subpart DDDDD	See SB01	none	n/a
CHS	Coal Handling System	391-3-1-.02(2)(n)	3.4.5, 3.4.6	none	n/a
AHS	Ash Handling System	391-3-1-.02(2)(n)	See CHS	none	n/a
MHS	Materials Handling System	391-3-1-.02(2)(e) 391-3-1-.02(2)(n) 40 CFR 60 Subpart A 40 CFR 60 Subpart OOO	3.3.4, 3.4.5, 3.4.6, 3.4.12	none	n/a

C. Equipment & Rule Applicability

***Permit Amendment No. 4911-149-0001-V-02-1 issued on March 7, 2007*:**

This permit amendment incorporates changes made to Georgia Rules for Air Quality Control 391-3-1-.02(2)(jjj) passed by the Georgia Department of Natural Resources Board on December 6, 2006. The revised rules include lowering the seven-plant ozone season NOx average from 0.20 lb/MMBtu to 0.18 lb/MMBtu and a new site-average NOx rate for Plant Scherer of 0.17 lb/MMBtu effective May 1, 2007. In addition, there are new specific unit targets for Plants Scherer and Branch. For Plant Scherer, the revised unit targets are 0.20 lb/MMBtu, 0.17 lb/MMBtu, 0.15 lb/MMBtu, and 0.16 lb/MMBtu for Units 1, 2, 3 and 4 respectively. For Plant Branch, the revised unit targets are 0.55 lb/MMBtu for Units 1 & 2 and 0.45 lb/MMBtu for Units 3 & 4. The unit targets at the other five plants will remain unchanged. At these NOx emission rates, Georgia Power plants will be in compliance with the five-plant, seven-plant and Scherer-site ozone season NOx averages listed under 391-3-1-.02(2)(jjj).

***Permit Amendment No. 4911-149-0001-V-02-2 issued on August 21, 2007*:**

This permit amendment revised language, as requested by Georgia Power, in Conditions 5.2.1(d), 6.1.7(c)(iii), and 8.17.2 for clarification of requirements. This amendment also replaced Acid Rain Permit Application to update and include the combined-cycle units.

***Permit Amendment No. 4911-149-0001-V-02-3 issued on October 30, 2008*:**

This permit amendment allowed the use of method ASTM D5142 or ASTM D3173 to analyze coal samples for moisture content and add compliance dates for Branch according to the Georgia Multipollutant Rule 391-3-1-.02(2)(sss). Although Georgia Power asked to use method ASTM D5142 in lieu of ASTM D3173, EPD's Source Monitoring Program has indicated that both methods should be left in permit since the D3173 (manual) method is the reference method.

***Permit Amendment No. 4911-149-0001-V-02-4 issued on November 25, 2008*:**

This permit amendment included method ASTM D1522 to determine No. 2 fuel oil sulfur content in Condition 6.2.3, included Methods D4629 and D3228 to determine No. 2 fuel oil nitrogen content in Condition 4.1.3.o.

Georgia Power also requested updating street address and plant contact information which included changing the street address, city and county where the plant is located. EPD does not agree with this change. The change includes changing the county from Heard to Carroll County. Carroll County is nonattainment for ozone where Heard County is not. Also the emissions units are physically located in Heard County. EPD agrees to add the street number and change the city but the county where the facility is located will remain unchanged.

***Permit Amendment No. 4911-149-0001-V-02-5 issued on March 12, 2009*:**

This application is processed as a significant modification without construction because this permit application requires changes to the current NO_X averaging plan. The facility has requested to update the Title IV Acid Rain Program Phase II NO_X averaging plan for years 2009 to 2013 for Emission Units SG01 and SG02 in Condition 7.9.7. The facility has requested to use the Title IV fast-track modification option in accordance with 40 CFR 72.82 to update the NO_X averaging plan.

The NO_X averaging plan has been revised from 0.47 lb/MMBtu (2007 to 2011 plan) to 0.46 lb/MMBtu (2009 to 2013 plan). The unit-specific alternative contemporaneous emission limitations have not changed in comparison to the 2007 to 2011 plan, but the unit-specific heat input limits have been updated for Emission Units SG01 and SG02 in Condition 7.9.7. The U.S. EPA Acid Rain Program Permit Application for Phase II NO_X Averaging Plan has been included in this permit in the Appendix (Attachment D).

***Permit Amendment No. 4911-149-0001-V-02-6 issued on September 17, 2009*:**

This application is processed as a significant modification without construction because this permit amendment incorporates the requirements of 40 CFR 96 for Clean Air Interstate Rule (CAIR) for the SO_2 and NO_X Annual Trading Programs for Emission Units SG01, SG02, CT5A, CT6A/DB6A, CT6B/DB6B, CT7A/DB7A and CT7B/DB7B (denoted simply as Unit ID Nos. 1, 2, 5A, 6A, 6B, 7A, and 7B in CAIR Permit Application) in Section 7.15 and Attachment E. The facility is required to comply with the CAIR requirements in accordance with the Georgia Rules 391-3-1-.02(12) and 391-3-1-.02(13), and 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, and 96.322.

The CAIR Permit Application has been included in the Appendix (Attachment E) to ensure that all applicable CAIR requirements are incorporated into the Title V Permit. The facility is required to comply with the all the permit requirements in the CAIR Permit Application, including the NO_X emissions requirements, SO_2 emissions requirements, excess emissions requirements, and the monitoring, reporting and record keeping requirements.

***Permit Amendment No. 4911-149-0001-V-02-7 issued on November 18, 2009*:**

This permit amendment incorporated changes to Georgia Rule 391-3-1-.02(2)(sss); reduced the frequency of particulate matter testing in Condition 4.2.1 due to changes in operation associated with the scrubber installations; added the monitoring of sparger submergence level in the scrubber; added the excursion level definition in Condition 6.1.7; and revised the monitoring requirements for the affected Materials Handling System in Condition 5.2.20

***Permit Amendment No. 4911-149-0001-V-02-8 issued on November 30, 2010*:**

This permit amendment incorporated Georgia Rule (uuu) requirements for Steam Generating Units 1 and 2 (Emission Unit IDs: SG01 and SG02) and updated the visible emissions requirements for the Materials Handling System (Emission Unit ID: MHS).

***Permit Amendment No. 4911-149-0001-V-02-9 pending (Title V Application No. 20827)*:**

Template Conditions 6.1.3, 6.1.4 and 8.14.1 were updated in September 2011 to allow up to 60 days to submit periodic reports. Alternative reporting deadlines are allowed per 40 CFR 70.6, 40 CFR 60.19(f) and 40 CFR 63.10(a).

Revision of the periodic reporting deadlines in Conditions 6.2.13, 6.2.22, and 6.2.27.

Emission and Operating Caps:
The two steam generating units (SG01 and SG02), startup boilers (SB01 and SB02) and the combustion turbine (CT5) are permitted to burn only certain fuels. The steam generating units can burn only coal, with No. 2 fuel oil, biodiesel, and biodiesel blends used for startup and flame stabilization. These emission units may also burn small amounts of sawdust, biomass, synfuel or used oil which, if burned, would be blended with the coal during normal operation. These limits apply to all steam generating units on a facility-wide basis. The startup boilers and combustion turbine can only burn No. 2 fuel oil, biodiesel, and biodiesel blends. The startup boilers can also burn propane for startup only. These operating caps eliminate any possibility of PSD or NSPS applicability resulting from increased emissions. The operating caps also preclude the necessity of more stringent and/or frequent periodic monitoring from the combustion of these materials. The used oil is required to meet certain specifications in order to be burned. In order to safeguard the public from the combustion of highly contaminated used oil, limits have been set under the authority of general state regulations.

Georgia Rules (jjj) and (nnn) NOx Reduction during the Ozone Season

In 2002, two new ozone standards had to be incorporated into the permit as follows: (1) conditions to implement the NOx emission reduction requirements specified by Georgia Rules for Air Quality Control 391-3-1-.02(2)(jjj)3 and 391-3-1-.02(2)(jjj)4; (2) conditions to implement the NOx emission reduction requirements specified by Georgia Rule for Air Quality Control 391-3-1-.02(2)(nnn); and (3) conditions which establish a NOx emissions cap on the coal-fired steam generating units within the 7 – plants (Bowen, Branch, Hammond, McDonough/Atkinson, Scherer, Wansley, and Yates), on a combined basis. Georgia Rule 391-3-1-.02(2)(jjj) applies to affected units, and the term affected units is defined as all coal-fired electric utility steam generating units with a maximum heat input greater than 250 MMBtu/hr. Georgia Rules (jjj)3 and (jjj)5 covers all coal-fired electric utility steam generating units located in the counties stated in Georgia Rule (jjj)8 and all affected units are owned and/or operated by Georgia Power. Georgia Rule (jjj)3 is referred to, in this narrative, as the 5-plant plan and the 5-plant plan covers Georgia Power - Plants Bowen, Hammond, McDonough/Atkinson, Wansley, and Yates. Georgia Rule (jjj)5 is referred to, in this narrative, as the 7-plant plan and the 7-plant plan covers Plants Bowen, Branch, Hammond, McDonough/Atkinson, Scherer, Wansley, and Yates.

The emission rates and limits have been adjusted in Permit Amendment 4911-149-0001-V-02-1.

In accordance with revised Georgia Rule 391-3-1-.02(2)(jjj), Georgia Power proposed an alternative NOx emission limit for Plant Branch and Plant Scherer. These alternative emission limits are based on a 30-day rolling average beginning May 1 and ending September 30 of each year beginning in 2007. These averages are not greater than 0.13 lb/mmBtu (for the 5-plant plan) and 0.18 lb/mmBtu (for the 7-plant plan). The following table illustrates Georgia Power's proposal/changes found in Application No. 17133 and was included in Permit Amendment 4911-149-0001-V-02-1.

Unit	Heat Input (MMBtu/30-day)	Target Rate (lb/MMBtu)	Calculated NOx Tons/30-day
Bowen 1	4,779,871	0.07	167.3
Bowen 2	4,588,630	0.07	160.6
Bowen 3	6,148,817	0.07	215.2
Bowen 4	5,859,516	0.07	205.1
Hammond 1	620,946	0.42	130.4
Hammond 2	603,106	0.42	126.7
Hammond 3	575,279	0.42	120.8
Hammond 4	3,209,623	0.07	112.3
McDonough 1	1,660,849	0.26	215.9
McDonough 2	1,289,884	0.26	167.7
Wansley 1	5,388,678	0.07	188.6
Wansley 2	4,856,149	0.07	170.0
Yates 1	671,034	0.38	127.5
Yates 2	639,085	0.38	121.4
Yates 3	629,137	0.38	119.5
Yates 4	776,745	0.33	128.2
Yates 5	796,902	0.33	131.5
Yates 6	1,898,675	0.26	246.8
Yates 7	1,818,067	0.26	236.3
5-Plant Total	46,810,990		3,091.8
	5-Plant Rate	**0.13**	
Branch 1	1,339,226	~~0.50~~ 0.55	334.8
Branch 2	1,485,502	~~0.50~~ 0.55	371.4
Branch 3	2,800,953	~~0.50~~ 0.45	700.2
Branch 4	2,810,067	~~0.50~~ 0.45	702.5
Scherer 1	5,335,479	~~0.30~~ 0.20	800.3
Scherer 2	5,893,058	~~0.30~~ 0.17	884.0
Scherer 3	5,358,032	~~0.15~~ 0.15	401.9
Scherer 4	5,853,924	~~0.20~~ 0.16	585.4
7-Plant Total	77,687,815		7,872.3
	7-Plant Rate	**~~0.20~~ 0.181**	

Scherer Site Total	**22,440,493**	**0.170**	**1,905**

Plant Wansley also has one simple cycle combustion turbine (emission unit ID CT5A). The combustion turbines are subject to the requirements of Georgia Rule 391-3-1-.02(2)(nnn) – "NOx Emissions from Large Stationary Gas Turbines" because the unit has a nameplate capacity of greater than 25 MWs. The turbine is subject to the Georgia Rule (nnn) requirements specified by Georgia Rule (nnn)1(i) because they were permitted before April 1, 2000, are located at a stationary source with no natural gas, and it is not subject to Georgia Rules 391-3-1-.03(8)(c)14 and 391-3-1-.03(8)(c)15. Georgia Rule (nnn)1(i) establishes a NOx emission limit of 30 ppm at 15% oxygen, on a dry basis, and the requirements of Georgia Rule (nnn)1(i) apply during the period May 1 through September 30 of each year, beginning 2003. The requirements of Georgia Rule (nnn) apply during normal source operation which includes periods of startup and shutdown.

Combustion turbine with emission unit ID CT5A is unable to comply with the NOx emission limit of 30 ppm at 15% oxygen on a dry basis. Thus, the Title V permit amendment will prohibit the operation of this turbine for any reason during the ozone season beginning in 2003.

Georgia Rule (sss) Multi-pollutant Rule

The facility is required to install a selective catalytic reduction (SCR) system and a flue gas desulfurization (FDG) system on the steam generating units. Georgia Rule (sss) explicitly lists the dates in which all of the Georgia Power Plants must be equipped with selective catalytic reduction, flue gas desulfurization, sorbent injection and/or baghouse as specified in the rule text.

The facility satisfied the installation of pollution control equipment with the following: Unit 1 had a SCR and FGD installed in 2008, and Unit 2 had a SCR and FGD installed in 2009. The construction and operation of these units were permitted prior to the last renewal. The initial requirements were added in Permit Amendment 4911-149-0001-V-02-3 and updates have been incorporated in Permit Amendment 4911-149-0001-V-02-7.

Federal Rule Standards:

Steam Generating Units (SG01 and SG02)

Emission units SG01 and SG02 were under construction before August 17, 1971. As a result, they are not subject to 40 CFR 60 Subpart D, Da, or Db, which have effective dates of August 17, 1971 or later.

The steam generating units (SG01 and SG02) are potentially subject to 40 CFR 63, Subpart UUUUU: National Emission Standards for Hazardous Air Pollutants from Coal and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units which was finalized on December 16, 2011 but has not been formally promulgated. This rule will become effective on April 16, 2012.

Startup Boilers (SB01 and SB02)

The steam generating units are not subject to 40 CFR 63, Subpart DDDDD "Industrial, Commercial and Institutional Boilers and Process Heaters" because while Plant Wansley contains boilers, the units are all electric utility steam generating boilers that generate steam to produce electricity for sale. Plant Wansley does have two start-up boilers that could potentially be classified as limited use and only subject to the initial notification requirements.

Combustion Turbine (CT5A)
The simple cycle combustion turbine is subject to 40 CFR 60 Subpart GG (and 40 CFR 60 Subpart A) because it was constructed after October 3, 1977 and has a heat input at peak load greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired (approximately 3 megawatts).

The combustion turbine (Emission Unit CT5) is subject to 40 CFR 63 Subpart YYYY - National Emission Standard for Hazardous Air Pollutants: Stationary Combustion Turbines. Since the affected unit is an existing stationary combustion turbine, it does not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for an existing stationary combustion turbine.

Materials Handling System (MHS)

40 CFR 60 Subpart OOO applies to the operations associated with the limestone crushing, part of the MHS. Applicability for this subpart is triggered if a "fixed crushed stone plant" with a capacity greater than 25 tons per hour of stone crushed is constructed (40 CFR 60.670). Plant Wansley will utilize a wet ball mill that is designed to crush 70 tons of limestone per hour.

Limestone is unloaded from railcars into hoppers. Dust collection systems are installed at the hopper and are used to control dust during the unloading processes. At the time of the application, Georgia Power believed that the 40 CFR 60 Subpart OOO requirements applied to this equipment. At the time EPD agreed with this determination and worked with Georgia Power to develop a testing protocol and permit requirements for the system. After further investigation by Georgia Power, it is believed that the railcar unloading of the limestone is exempt from the affected facility's due to being included in "truck dumping" as per 40 CFR 60.670(a)(1). Also, these facilities are specifically exempted from both the 7% opacity requirement and the particulate matter standard per 40 CFR 60.672(d) and the definition of truck dumping. EPD agrees with this new determination that railcar unloading is included as part of the definition of truck dumping and therefore is not subject to 40 CFR 60 Subpart OOO requirements. Therefore, Georgia Power will have to comply with Georgia's fugitive dust requirements that are already detailed in their permit for these operations.

SIP Rule Standards:

Steam Generating Units (SG01 and SG02)

These emission units are subject to Georgia Rule 391-3-1-.02(2)(b). All emission units which are subject to any emission limitations under 391-3-1-.02(2) are subject to Georgia Rule (b) unless they are subject to a more stringent opacity standard. These emission units are subject to Georgia Rule 391-3-1-.02(2)(d)1(iii) because they were under construction before January 1, 1972 and the source (i.e. each steam generating unit at Plant Wansley) has a heat input capacity greater than 2,000 million Btu per hour. These emission units are subject to Georgia Rule 391-3-1-.02(2)(g)2 because they were under construction before January 1, 1972 and have a heat input capacity greater than 100 million Btu per hour.

Rule (d)1(iii) limits PM emissions to 0.24 lb/mmBtu heat input. Georgia Rule (g)2 limits the sulfur content of the fuel to 3%, by weight. Georgia Rule (b) limits visible emissions to 40 percent opacity.

Georgia Rule (jjj) – as discussed above, the facility is subject to individual limits, 5-plant plan and/or the 7-plant averaging plan.

Georgia Rule (uuu) – SO_2 Emissions limits; as a part of the Multi-pollutant Rule (sss), Georgia Rule (uuu) adds a percent removal requirement for SO_2 of 95% from the steam generating units. These requirements and listed exemptions were incorporated in Permit Amendment 4911-149-0001-V-02-8.

<u>Combustion Turbine (CT5A)</u>

This emission unit is subject to Georgia Rules 391-3-1-.02(2)(b) and (g)1(i). All emission units which are subject to any emission limitations under 391-3-1-.02(2) are subject to Georgia Rule (b) unless they are subject to a more stringent opacity standard and all fuel burning sources are subject to Rule (g). Simple cycle combustion turbines are not subject to Georgia Rule (d) because they do not meet the definition of "fuel burning equipment" in the Georgia Rules.

This emission unit is subject to Georgia Rule 391-3-1-.02(2)(g)1(i) because it was under construction after January 1, 1972 and has a heat input capacity greater than 250 million Btu per hour. The combustion turbine is rated at 904 MMBtu/hr. It was actually constructed in 1979.

Rule (b) limits visible emissions to 40 percent opacity. Since the combustion turbine burns only No. 2 fuel oil, visible emissions should be very low. Higher levels of visible emissions may be seen during startup when burning fuel oil.

Georgia Rule (nnn) – as discussed above, the combustion turbine is subject to Rule (nnn) which applies during the ozone season.

<u>Startup Boilers (SB01 and SB02)</u>

This emission unit is subject to Georgia Rules 391-3-1-.02(2)(b) and (g)2. All emission units which are subject to any emission limitations under 391-3-1-.02(2) are subject to Georgia Rule (b) unless they are subject to a more stringent opacity standard and all fuel burning sources are subject to Rule (g).

Rule (b) limits visible emissions to 40 percent opacity. Since the boilers burn only No. 2 fuel oil, biodiesel, biodiesel blends and propane (startup only), visible emissions should be very low.

Rule (d)1(ii) limits PM emissions to 0.34 lb/MMBtu heat input. Georgia Rule (g)2 limits the sulfur content of the fuel to 3%, by weight.

Coal, Ash, and Materials Handling (CHS, AHS, and MHS)

Emission Units CHS, AHS, MHS are fugitive emission sources which are subject to Georgia Rule 391-3-1- .02(2)(n). Rule (n) requires Georgia Power to take all reasonable precautions to prevent fugitive dust from becoming airborne and limits the opacity to 20 percent.

The Materials Handling System is also subject to Georgia Rule (e) which limits the amount of PM emissions from the entire system and is based on actual process input.

D. Compliance Status

The facility is operating in compliance with their Air Quality Permit.

E. Operational Flexibility

None applicable.

F. Permit Conditions

Equipment Emission Caps and Operating Limits

Draft Condition 3.2.1 describe what fuels may be burned in the steam generating units. Biodiesel and biodiesel blends were added at possible fuels during startup as a part of this permit renewal. The remainder of the condition is unchanged from the last permit renewal.

Draft Condition 3.2.2 contains specific requirements pertaining to used oil combustion. This condition has remained unchanged from the last permit renewal.

Draft Condition 3.2.3 states that the combustion turbine may only burn No. 2 fuel oil, biodiesel, or biodiesel blends. Biodiesel and biodiesel blends were added at possible fuels during startup as a part of this permit renewal.

Draft Condition 3.2.4 states that the start-up boilers may only burn No. 2 fuel oil, biodiesel, biodiesel blends or propane. Biodiesel and biodiesel blends were added at possible fuels during startup as a part of this permit renewal.

Draft Condition 3.2.5 limits the hours of operation of the combustion turbine to less than 500 hours per year. This condition has remained unchanged from the last permit renewal.

Draft Condition 3.2.6 defines the NOx emission limit for the 7-plant plan, on a combined basis, for the ozone season. The beginning date of the 2005 ozone season has been removed as a part of this renewal all other parts of this condition have remained unchanged since the last permit renewal.

Equipment Federal Rule Standards

Draft Condition 3.3.1 contains the general requirement of NSPS Subpart A and GG for the combustion turbine CT5A. This condition has been split because portions are no longer applicable to this facility. The combined cycle combustion turbines (Emission Unit ID: CT6A, CT6B, CT7A, and CT7B) have been transferred to Southern Power in Permit No. 4911-149-0011-V-01-0. The applicable portions of this condition have remained unchanged since the last permit renewal.

Draft Condition 3.3.2 limits nitrogen oxides emissions from the combustion turbine in accordance with 40 CFR 60.332. This condition has remained unchanged from the last permit renewal.

Draft Condition 3.3.3 limits the fuel sulfur content of the fuel burned in the combustion turbine in accordance with 40 CFR 60.333. This condition has remained unchanged from the last permit renewal.

Original Permit Condition 3.3.4 – 3.3.18 are no longer applicable to this facility. The combined cycle combustion turbines have been transferred to Southern Power in Permit No. 4911-149-0011-V-01-0.

Draft Condition 3.3.4 comes from Original Condition 3.3.19 and was updated in Permit Amendment 4911-149-0001-V-02-7. This condition contains the requirements of 40 CFR, 60 Subpart OOO for the affected portion of the materials handling system (Emission Unit ID MHS). The permit amendment added railcar unloading to the list of exemptions.

Draft Condition 3.3.5 contains the requirements of NESHAP Subpart A and DDDDD for the startup boilers SB01 and SB02. This is a new requirement as a part of this renewal permit.

Equipment SIP Rule Standards

Draft Condition 3.4.1 limits particulate matter emissions from the steam generating units in accordance with Georgia Rule (d). This condition has remained unchanged from the last permit renewal.

Draft Condition 3.4.2 limits visible emissions from all the fuel burning sources (steam generating units, startup boilers, and combustion turbine) in accordance with Georgia Rule (b). This condition has remained unchanged from the last permit renewal.

Draft Condition 3.4.3 limits the fuel sulfur content of the fuel burned in the fuel burning sources (except the combustion turbine which is covered in Condition 3.3.3) in accordance with Georgia Rule (g). This condition has remained unchanged from the last permit renewal.

Draft Condition 3.4.4 limits particulate matter emissions from the startup boilers in accordance with Georgia Rule (d). This condition has remained unchanged from the last permit renewal.

Draft Conditions 3.4.5 and 3.4.6 describe the requirements for fugitive emission sources for the Ash Handling System and the Coal Handling System in accordance with Georgia Rule (n). These conditions have remained unchanged from the last permit renewal.

Draft Conditions 3.4.7, 3.4.8, 3.4.9, and 3.4.10 define the NOx emission limits per Georgia Rule (jjj). Condition 3.4.10 was updated in Permit Amendment 4911-149-0001-V-02-1 which incorporated the new rule changes in May of 2007. All other conditions have remained unchanged from the last permit renewal.

Draft Conditions 3.4.11 contain the requirements of Georgia Rule (nnn) for the combustion turbine CT5A. This condition has remained unchanged from the last permit renewal.

Draft Condition 3.4.12 contains the Georgia Rule (e) requirements for the Materials Handling System (MHS). This condition has remained unchanged from the last permit renewal.

Draft Conditions 3.4.13 was added in Permit Amendment 4911-149-0001-V-02-8. This condition incorporates the requirements for steam generating units with Emission Unit IDs SG01 and SG02 to comply with the Georgia Rule for SO_2 emissions from Electric Utility Steam Generating Units.

Draft Condition 3.4.14 was added in Permit Amendment 4911-149-0001-V-02-8. This condition lists the allowable time periods where emissions can be in excess of the limits in Condition 3.4.13.

Draft Condition 3.4.15 comes from Original Condition 3.2.7 which was added in Permit Amendment 4911-149-0001-V-02-3 and updated in 4911-149-0001-V-02-7 which contains the requirements of Georgia Rule 391-3-1-.02(2)(sss). The effective dates have been removed since they have already passed and the equipment has been installed.

IV. Testing Requirements (with Associated Record Keeping and Reporting)

A. General Testing Requirements

The permit includes a requirement that the Permittee conduct performance testing on any specified emission unit when directed by the Division. Additionally, a written notification of any performance test(s) is required 30 days (or sixty (60) days for tests required by 40 CFR Part 63) prior to the date of the test(s) and a test plan is required to be submitted with the test notification. Test methods and procedures for determining compliance with applicable emission limitations are listed and test results are required to be submitted to the Division within 60 days of completion of the testing.

Permit Condition 4.1.3o was updated in Permit Amendment 4911-149-0001-V-02-4 to include additional test methods for the determination of the nitrogen content of fuel oil.

Permit Condition 4.1.3t was added in Permit Amendment 4911-149-0001-V-02-8 for the determination of sulfur dioxide emissions from the steam generating units for the purposes of verifying compliance with Georgia Rule 391-3-1-.02(2)(uuu).

Permit Condition 4.1.4 has been carried over from the initial Title V permit with no changes. This state only enforceable condition requires the Permittee to provide notification of a test plan in accordance with Condition 4.1.2.

B. Specific Testing Requirements

Annual testing for particulate matter emissions is required on each steam generating unit. Testing is not required on the start-up boilers or the combustion turbine. The testing conditions were in the facility's previous permits.

Permit Condition 4.2.1, which requires PM testing for each of the steam generating units, has been updated in Permit Amendment 4911-149-0001-V-02-7. Modified Condition 4.2.1a is changing the frequency for particulate testing due to the changes in operation of the steam generating units associated with the scrubber installations. This testing requirement applies to the scrubber bypass stacks (ST01 and ST02). The modified condition changes the existing testing requirements to require a test after 8760 operating hours or 60 months for the unit, whichever comes first.

To address public interest and concern for sulfur dioxide and particulate matter emissions, the scrubbers were added downstream of the electrostatic precipitators. Historically, compliance with the particulate matter standard has easily been achieved with the electrostatic precipitators alone. Therefore, with the additional particulate matter control equipment and the CAM Plan, the Division is relaxing the testing requirement to once per permit term, or upon request.

Condition 4.2.1b was added and requires a particulate matter test on steam generating units 1 and 2 on the scrubber stacks (ST03 and ST04). The tests are required once every 60 months or as requested by the Division.

Original Permit Condition 4.2.2 required initial performance testing on the materials handling system (MHS) to determine compliance with Condition 3.3.19. Testing was completed on October 1, 2009; this condition has been satisfied and therefore removed from the permit.

Draft Permit Condition 4.2.2 is taken from Permit Condition 4.2.4 which was added in Permit Amendment 4911-149-0001-V-02-8. Permit Condition 4.2.4 requires the Permittee to conduct initial and subsequent performance tests on steam generating units with Emission Unit IDs SG01 and SG02 based upon the 95 percent reduction required by Condition 3.4.13 for the first 30 successive boiler operating days following the date of compliance with Georgia Rule 391-3-1-.02(2)(uuu).

V. Monitoring Requirements

A. General Monitoring Requirements

Condition 5.1.1 requires that all continuous monitoring systems required by the Division be operated continuously except during monitoring system breakdowns and repairs. Monitoring system response during quality assurance activities is required to be measured and recorded. Maintenance or repair is required to be conducted in an expeditious manner.

B. Specific Monitoring Requirements

Draft Permit Condition 5.2.1 was taken from Original Condition 5.2.1 with some modifications and updates. Condition 5.2.1 requires the installation and operation of continuous monitoring systems at the facility. 5.2.1c-e are no longer applicable to this facility. The combined cycle combustion turbines have been transferred to Southern Power in Permit No. 4911-149-0011-V-01-0. Draft Condition 5.2.1c. was added in Permit Amendment 4911-149-0001-V-02-8 and requires the installation, calibration, maintenance and operation of a continuous emissions monitoring systems (CEMS) for the measurement of sulfur dioxide in the combined exhaust for steam generating units with Emission Unit IDs SG01 and SG02.

Draft Condition 5.2.2 was added as a part of this renewal and split out the continuous monitored parameters from the CEMS requirements above as consistent with our current template. Draft Condition 5.2.1b. was updated in Permit Amendment 4911-149-0001-V-02-7 which adds the use of sparger tube submergence level in the scrubber vessel for the continuous monitoring system (CMS) for the scrubbers on Units 1 and 2 (Emission Unit IDs SG01 and SG02).

Original Permit Condition 5.2.2 was deleted in Permit Amendment 4911-149-0001-V-02-8. Daily coal sampling is no longer required because the facility will be using the SO_2 CEMS to determine the daily average sulfur content of coal burned at the facility. Therefore, Condition 5.2.2 will be deleted and replaced with new Condition 5.2.18

Draft Permit Condition 5.2.3 was taken from original Condition 5.2.3 and has remained unchanged from the last permit renewal.

Draft Permit Condition 5.2.4 was taken from original Condition 5.2.4 and has remained unchanged from the last permit renewal.

Original Permit Condition 5.2.5 – 5.2.11 are no longer applicable to this facility. The combined cycle combustion turbines have been transferred to Southern Power in Permit No. 4911-149-0011-V-01-0.

Draft Permit Condition 5.2.5 was taken from original Condition 5.2.12 and has remained unchanged from the last permit renewal.

Draft Permit Conditions 5.2.6 and 5.2.7 were taken from original Permit Condition 5.2.13 and 5.2.14 and were updated in Permit Amendment 4911-149-0001-V-02-7. The conditions contain the CAM plans for the steam generating units. The CAM plan conditions were modified to include the performance criteria tables for SG01 and SG02 while FGD1 and FGD2 are in operation. The new indicator included is the sparger tube liquid submergence level in each of the scrubbers.

Draft Permit Condition 5.2.8 was taken from original Permit Condition 5.2.15 and has remained unchanged from the last permit renewal. This condition contains CAM requirements for the combustion turbine CT5A.

Draft Permit Conditions 5.2.9, 5.2.10, 5.2.11, and 5.2.12 were taken from original Permit Conditions 5.2.16, 5.2.17, 5.2.18, and 5.2.19 and have remained unchanged from the last permit renewal. These conditions contain CAM recordkeeping and reporting requirements.

Draft Permit Condition 5.2.13 was taken from original Permit Condition 5.2.20 and was updated in Permit Amendment 4911-149-0001-V-02-7 and Permit Amendment 4911-149-0001-V-02-8. Condition 5.2.20 has been modified to include updated language to require visual inspection of all emission points in the Material Handling System (Emission Unit ID MHS) to note the occurrence of any visible emissions and any mechanical failures or malfunction resulting in an increase in emissions.

Original Permit Condition 5.2.21 required the facility to submit an updated CAM Plan for the control of particulate emissions from the steam generating units because of the addition of the scrubber systems. The facility satisfied this requirement in Permit Amendment 4911-149-0001-V-02-7 and therefore this requirement has been deleted.

Draft Permit Conditions 5.2.14 through 5.2.20 were added in Permit Amendment 4911-149-0001-V-02-8 as Permit Conditions 5.2.22 through 5.2.28.

Draft Condition 5.2.14 come from Original Condition 5.2.22 and requires the Permittee to operate the SO_2 CEMS required by Permit Condition 5.2.1c. to be operated and the data is to be recorded during all periods of operation of the affected units, steam generating units with Emission Unit IDs SG01 and SG02 including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments and any period allowed under Georgia Rule 391-3-1-.02(2)(uuu)(4).

Draft Condition 5.2.15 come from Original Condition 5.2.23 and requires the Permittee to obtain SO_2 emission data for at least 75 percent of all operating hours for each 30 successive boiler operating days. If the minimum data requirement cannot be met with a CEMS, the Permittee shall supplement emission data with an alternative Division approved monitoring system.

Draft Condition 5.2.16 come from Original Condition 5.2.24 and requires the Permittee to prepare and submit to the Division for approval a unit specific monitoring plan for the SO_2 CEMS required by Condition 5.2.1c, at least 45 days before commencing certification testing of the monitoring system.

Draft Condition 5.2.17 come from Original Condition 5.2.25 and requires the Permittee to install, certify, and operate the SO_2, CO_2, and O_2 CEMS as stated in the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** or according to 40 CFR Part 75.

Draft Condition 5.2.18 come from Original Condition 5.2.26 and contains the formulas for how the Permittee is to determine the daily average sulfur content (%S) of coal burned at the facility.

Daily coal sampling is no longer required because the facility will be using the SO_2 CEMS to determine the daily average sulfur content of coal burned at the facility. Therefore, Condition 5.2.2 will be deleted and replaced with Original Condition 5.2.26

Draft Condition 5.2.19 come from Original Condition 5.2.27 and requires the Permittee to monitor and record the flue gas flow through the Selective Catalytic Reduction Systems (SCRs) SCR1 and SCR2 during the ozone season.

Draft Condition 5.2.20 come from Original Condition 5.2.28 and requires the Permittee to demonstrate compliance with Georgia Rule (sss) and Georgia Rule (uuu).

C. Compliance Assurance Monitoring (CAM)

40 CFR 64-Compliance Assurance Monitoring: This review analyzes the applicability of 40 CFR 64 – "Compliance Assurance Monitoring."

The ESP's (Source Codes EP01 and EP02) and the FGD's (Source Codes FGD1 and FGD2) meet the definition of a control device as defined in Part 64.1. In addition, each Steam Generating Unit is subject to a Particulate Matter emission standard. The controlled Particulate Emissions for each of the two emission units ranges from approximately 101 tons per year to 124 tons per year. The Part 64 applicability threshold, in this case, for Particulate Emissions is 100 tons per year. Thus, each Steam Generating Unit is a Part 64 *Pollutant Specific Emission Unit* (PSEU) for Particulate Emissions. The existing Title V Permit for Plant Wansley does not define a *continuous compliance determination method* for the Particulate Emissions limitation for each steam-generating unit. Thus, Plant Wansley is not exempt from the requirements of Part 64 for Particulate Emissions. With that in mind, each Steam Generating Unit is subject to Part 64 for Particulate Emissions.

Combustion Turbine CT5A utilizes water injection to control NOx emissions. Water injection meets the definition of a control device as defined in Part 64.1. In addition, the combustion turbine is subject to a NOx emission standard. The Part 64 applicability threshold, in this case, for NOx emissions is 100 tons per year. The controlled NOx emissions from the combustion turbine is above the 100 tons per year threshold. Thus, the combustion turbine CT5A is a Part 64 *Pollutant Specific Emission Unit* (PSEU) for NOx Emissions. The existing Title V Permit for Plant Wansley does not define a *continuous compliance determination method* for the NOx Emissions limitation for the combustion turbine. Thus, Plant Wansley is not exempt from the requirements of Part 64 for NOx Emissions. With that in mind, the combustion turbine is subject to Part 64 for NOx Emissions.

The requirements of Part 64 do not apply to Steam Generating Units for CO and VOC emissions because there are no control devices for these air pollutants. The Steam Generating Units are configured with combustion modification technologies to minimize the formation of NOx, CO and VOC but these technologies are not considered control devices under Part 64. The Part 64 definition of a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of combustion or other process design features or characteristics. NOx emissions are controlled during the ozone season by Selective Catalytic Reduction (SCR) units to meet the limits set in Georgia Rule 391-3-1-.02(2)(jjj). The NOx emissions are exempt from the requirements of Part 64 because the Steam Generating Units are subject to Acid Rain Regulations for NOx and therefore are exempt per 64.2(b)(1)(iii). In addition, Part 64 does not apply for Georgia Rule (jjj) since the NOx CEMS are the continuous compliance determination method specified by the rule and therefore are exempt per 64.2(b)(1)(vi). The SO_2 emissions are controlled by the FGD units to meet the limits set in Georgia Rule 391-3-1-.02(2)(uuu). The SO_2 emissions are exempt from the requirements of Part 64 because the Steam Generating Units are subject to Acid Rain Regulations for SO_2 and therefore are exempt per 64.2(b)(1)(iii). In addition, Part 64 does not apply for Georgia Rule (uuu) since the SO_2 CEMS are the continuous compliance determination method specified by the rule and therefore are exempt per 64.2(b)(1)(vi).

The start-up boilers are not subject to CAM because they are not equipped with control devices as defined in Part 64.1.

The requirements of Part 64 do not apply to the Material Handling System (MHS), the Coal Handling System (CHS) or the Ash Handling System (AHS) because these units are not equipped with control devices as defined in Part 64.1.

Georgia Power identified three PSEUs that are subject to CAM in their CAM plan. They are listed in Condition 5.2.5 and are, as follows, with their specific pollutant(s) and control devices:

Emission Unit	Pollutant	Stack Number	Control Device
Steam Generator Unit 1	Particulate Matter	ST01 ST03	ESP (EP01) on the bypass stack FGD (FGD1)
Steam Generator Unit 2	Particulate Matter	ST02 ST04	ESP (EP02) on the bypass stack FGD (FGD2)
Combustion Turbine 5A	Nitrogen Oxides		Water/fuel ratio

Please note that Steam Generating Units SG01 and SG02 exhaust through common stacks they have unique liners that separate the gas streams (i.e. scrubber bypass stacks ST01 and ST02); they are separate pollutant-specific emission units under Part 64. As part of the scrubber installation an additional stack was installed and again has unique liners for each Steam Generating Units SG01 and SG02 (i.e. scrubber stacks ST03 and ST04).

As the controlled potential to emit of Particulate Emissions from each Steam Generating Unit is greater than 100 tons per year, the required Part 64 data collection frequency is defined by 40 CFR 64.3(b)(4)(ii). This portion of the CAM regulation requires the Permittee to collect four or more data values equally spaced over each hour and average the values, as applicable, over the applicable averaging periods as determined in accordance with 40 CFR 64.3(b)(4)(i).

Steam Generating Units 1 and 2 are each controlled by an ESP (Source Codes EP01 and EP02) on the bypass stack liner and controlled by a FGD system (Source Codes FGD1 and FGD2) on the main stack liners. The primary indicator, for the bypass stack, of proper control device operation for particulate matter is a continuous opacity monitoring system (COMS). It has been determined that the opacity cap levels indicating unacceptable performance are: for Unit 1, a three-hour average of 40% opacity and for Unit 2, a three-hour average of 40% opacity. PM can either be vented to the ESP and then the FGD scrubber or in the event of scrubber malfunction; emissions can be vented to the ESP only. Under normal operation the ESP would only be used to remove ash from the gypsum so that it meets quality standards for purchase. The FGD scrubber is designated as the as the primary control device to achieve compliance with the PM standard. The primary indicator, for the main stack liners of proper control device operation for particulate matter is the sparger tube liquid submergence level in the FGD vessel for each unit.

As the controlled potential to emit of NOx Emissions from the combustion is greater than 100 tons per year, the required Part 64 data collection frequency is defined by 40 CFR 64.3(b)(4)(ii). This portion of the CAM regulation requires the Permittee to collect four or more data values equally spaced over each hour and average the values, as applicable, over the applicable averaging periods as determined in accordance with 40 CFR 64.3(b)(4)(i).

Combustion turbine CT5A is controlled by water injection. The primary indicator of proper control device operation for NOx is monitoring the fuel and water flow by the control system to calculate water/fuel flow ratio.

The applicable elements of the applicant's CAM plan are included in draft condition numbers 5.2.5, 5.2.6, 5.2.7, 5.2.8, 5.2.9, 5.2.10, 5.2.11, and 5.2.12.

VI. Record Keeping and Reporting Requirements

A. General Record Keeping and Reporting Requirements

The Permit contains general requirements for the maintenance of all records for a period of five years following the date of entry and requires the prompt reporting of all information related to deviations from the applicable requirements. Records, including identification of any excess emissions, exceedances, or excursions from the applicable monitoring triggers, the cause of such occurrence, and the corrective action taken, are required to be kept by the Permittee and reporting is required on a quarterly basis.

Template Conditions 6.1.3 and 6.1.4 were updated in September 2011 to allow ~60 days to submit periodic reports. Alternative reporting deadlines are allowed per 40 CFR 70.6, 40 CFR 60.19(f) and 40 CFR 63.10(a).

Condition 6.1.7a.i defines an excess emission of NOx as defined in Condition 6.2.13.

Condition 6.1.7a.ii defines an excess emission for combustion turbine (CT5A) any one-hour period during which the average water-to-fuel ratio falls below the ratio determined during the initial performance test that demonstrated compliance with the nitrogen oxides limit in Condition 3.3.2.

Condition 6.1.7a.iii defines an excess emission for any 4 hour rolling NOx average emissions that exceed the limit in Condition No. 3.3.2.

Condition 6.1.7b.i defines an exceedance for each Steam Generating Unit (Emission unit IDs SG01, or SG02) as any six-minute period during which the average opacity, as measured by the COMS, exceeds 40 percent. This is in regards to the limit placed on each boiler by Georgia Rule 391-3-.02(2)(b). Neither Georgia Rule (b) nor the Division's Procedures for Testing and Monitoring Sources of Air Pollutants has defined an excess emission for this rule, and it has been determined that this is an exceedance.

Condition 6.1.7b.ii defines an exceedance for the applicable equipment specified in Condition 3.2.6, during the ozone season, as a total 12 month NOx emission rate which exceeds 32,335.8 tons. This is in regards to the applicability of Georgia Rules 391-3-.03(8)(c)1 and 391-3-.03(8)(c)15.

Condition 6.1.7b.iii defines an exceedance for Combustion Turbine 5A as fuel oil sulfur content greater than 0.5% by weight. This is in regards to the limit placed on the combustion turbine by Subpart GG.

Condition 6.1.7b.iv defines an exceedance in any steam generating unit (Emission Unit IDs SG01 or SG02) or start-up boiler (Emission Unit IDs SB01 or SB02) as any fuel oil sulfur content greater than 3.0% by weight. This is in regards to the limit placed on the facility by Georgia Rule 391-3-1-.02(2)(g)2. Nothing has been defined in Rule (g) as an excess emission, so it has been determined that this is an exceedance.

Condition 6.1.7b.v defines an exceedances in any steam generating unit (emission unit IDs SG01 and SG02) as anytime coal derived synthetic fuel burned does not meet the specifications of Condition 3.2.1e.

Condition 6.1.7b.vi defines an exceedances in any steam generating unit (emission unit IDs SG01 and SG02) as any 30 day rolling average SO_2 percent reduction that is calculated in accordance with the procedure of Condition 6.2.16 that is less than 95% for any of the steam generating units with Emission Unit IDs SG01 and SG02 as defined in the permit.

Condition 6.1.7c.i defines an excursion for Unit 1 (Emission unit ID SG01), as any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 40 percent.

Condition 6.1.7c.ii defines an excursion for Unit 2 (Emission unit ID SG02), as any three-hour block average during which the arithmetic average opacity, as measured by the COMS exceeds 40 percent.

Condition 6.1.7c.iii defines an excursion level for any visible emissions or mechanical failure or malfunction discovered by the walk through described in Condition 5.2.13 that are not eliminated or corrected within 12 hours of first discovering the visible emissions or mechanical failure or malfunction.

Conditions 6.1.7c.iv and v define excursion levels for the operation of FGD1 and FGD2 for the sparger tube liquid submergence level in the scrubber vessel.

Condition 6.1.7c.vi defines an excursion during the ozone season any 30 consecutive operating day period in which the flue gas did not pass through the SCR for at least 90% of the operation hours during that period.

B. Specific Record Keeping and Reporting Requirements

Draft Condition 6.2.1 comes from Original Condition 6.2.1. As part of this renewal permit, biodiesel and biodiesel blends have been added as potential fuels in this condition. This condition requires Georgia Power to maintain monthly records of all fuels burned in the steam generating units at Plant Wansley. This condition requires records to be kept for the quantity of sawdust received (as opposed to the quantity of sawdust burned) because there is no reasonable way to accurately quantify the sawdust as it is being burned. If GPC burns sawdust, they typically would spread the sawdust on the coal pile when it is received and the sawdust would be burned shortly thereafter (as a small percentage of the total fuel). Over a period of a few weeks the quantity of sawdust received should be roughly equivalent to the quantity of sawdust burned. The same reasoning applies to the burning of biomass and coal-derived synthetic fuel.

Draft Condition 6.2.2 comes from Original Condition 6.2.2 which has remained unchanged since the last renewal. This condition requires Georgia Power to maintain records containing a representative ash content of the coal and a representative heat content of the sawdust. These values are needed in order to estimate emissions from the combustion of these fuels. It is expected that these values will not change much during the term of the permit. As long as these values do not change significantly (about +/- 10% for the heat content of the sawdust or about +/- 4% for the ash content, i.e. from 3% ash to 7.2% ash should be noted) Georgia Power need only maintain one representative record of each such value.

Draft Condition 6.2.3 comes from Original Condition 6.2.3 and was updated in Permit Amendment 4911-149-0001-V-02-4 and as a part of this renewal. Condition 6.2.3 was modified to include Method D1552 to determine No. 2 fuel oil sulfur content. The application submitted by Georgia Power stated using Method D1552 in combination with Method D4057 for acquiring the sample for testing. After reviewing the request, EPD determined that Method D1552 is a laboratory test method; whereas, Method D4057 is a sampling method. EPD moved Method D1552 to use in combination with Method D129 that is later stated in the condition. Georgia Power was notified and indicated that what EPD has proposed was the original intention and the application contained an error. The current condition requires the facility to comply with specifications defined in ASTM D396, D975 or D6751, obtain supplier certifications as in ASTM D396, D975 or D6751. As an alternative the facility can obtain a sample for analysis using procedures in ASTM D4057 and determine the sulfur content using ASTM D129 or D1552.

Original Condition 6.2.4 was reserved as to prevent an entire section renumber. This condition placeholder has been removed.

Draft Condition 6.2.4 comes from Original Condition 6.2.5 which has remained unchanged since the last renewal. This condition requires the facility to maintain a record of all actions taken in accordance with Condition 3.4.5 to suppress fugitive dust from the coal handling system (CHS) and the ash handling system (AHS).

Draft Condition 6.2.5 comes from Original Condition 6.2.6 which has remained unchanged since the last renewal. This condition requires the facility for each shipment of coal-derived synthetic fuel received, to obtain a supplier certification that each shipment of synthetic fuel to be received complies with Condition 3.2.1e.

Draft Condition 6.2.6 comes from Original Condition 6.2.7 which has remained unchanged since the last renewal. The facility is required to maintain monthly records of all fuel burned in Combustion Turbine Unit 5A.

Draft Condition 6.2.7 come from Original Condition 6.2.8 which has remained unchanged since the last renewal. The facility is required to maintain records specifying the hours per month of operation of combustion turbine CT5A due to the requirements of Georgia Rule (nnn) and applies during the ozone season.

Draft Condition 6.2.8 was taken from Original Condition No. 6.2.9 which has remained unchanged since the last renewal. This Condition requires the facility to record any time that combustion turbine CT5A is operated during the ozone season and submit the appropriate records in accordance with Georgia Rule (nnn). This condition was updated to removed the May 1, 2003 start date of the requirement.

Original Permit Conditions 6.2.10 – 6.2.16 are no longer applicable to this facility. The combined cycle combustion turbines have been transferred to Southern Power in Permit No. 4911-149-0011-V-01-0.

Draft Condition 6.2.9 comes from Original Condition 6.2.17 and has remained unchanged since the last renewal. This condition contains record keeping and reporting requirements associated with Georgia Rule (jjj) requirements and the 7-plant ozone season NOx emissions cap.

Draft Condition 6.2.10 comes from Original Condition 6.2.18 and has remained unchanged since the last renewal. This condition contains record keeping and reporting requirements associated with Georgia Rule (jjj) requirements and the 7-plant ozone season NOx emissions cap.

Draft Condition 6.2.11 comes from Original Condition 6.2.19 and has remained unchanged since the last renewal. This condition contains record keeping and reporting requirements associated with Georgia Rule (jjj) requirements and the 7-plant ozone season NOx emissions cap.

Draft Condition 6.2.12 comes from Original Condition 6.2.20 and has remained unchanged since the last renewal. This condition contains record keeping and reporting requirements associated with Georgia Rule (jjj) requirements and the 7-plant ozone season NOx emissions cap.

Draft Condition 6.2.13 comes from Original Condition 6.2.22 and has remained unchanged since the last renewal. This condition contains reporting requirements associated with Georgia Rule (jjj) requirements and the 7-plant ozone season NOx emissions cap.

Draft Condition 6.2.14 comes from Original Condition 6.2.23 and has remained unchanged since the last renewal. The facility may submit, via electronic media, any report required by Part 6.0 of this permit.

Original Condition 6.2.24 is no longer applicable. The facility satisfied the notification requirement of the equipment on May 15, 2008.

Draft Condition 6.2.15 was added in Permit Amendment 4911-149-0001-V-02-8 in Condition 6.2.25 which requires the Permittee to determine compliance with the SO_2 emissions limitations in Condition No. 3.4.13 based on the average emission rate for 30 successive boiler operating days.

Draft Condition 6.2.16 was added in Permit Amendment 4911-149-0001-V-02-8 in Condition 6.2.26 which requires the Permittee to determine compliance with the limitation using the procedures of Section 2.125.4 of the **Division's Procedures for Testing and Monitoring Sources of Air Pollutants**. The Permittee shall maintain the records in accordance with Section 2.125.5 of the aforementioned procedures document and use these records to prepare a quarterly report.

Draft Condition 6.2.17 was added in Permit Amendment 4911-149-0001-V-02-8 in Condition 6.2.27 which requires the Permittee shall submit written reports to the Division of reportable emissions under for each calendar quarter.

Draft Condition 6.2.18 was added in Permit Amendment 4911-149-0001-V-02-8 in Condition 6.2.28 which requires the Permittee to submit the information obtained under the requirements of Section 2.125.2(d) of the **Division's Procedures for Testing and Monitoring Sources of Air Pollutants** for that 30-day period, in the event emissions data as required by Section 2.125.4 of the Divisions Procedures for Testing and Monitoring Sources of Air Pollutants is not obtained for any 30 successive boiler operating days.

Draft Condition 6.2.19 was added in Permit Amendment 4911-149-0001-V-02-8 in Condition 6.2.29 which requires the Permittee to submit a signed statement to the Division indicating if any changes were made in operation of the emission control system during the period of data unavailability for any periods for which SO_2 emissions data are not available.

Draft Condition 6.2.20 was added in Permit Amendment 4911-149-0001-V-02-8 in Condition 6.2.30 which requires the Permittee to submit results of each RATA required under Section 2.125.3(j) of the Division's **Procedures of Monitoring and Testing of Air Pollutants** within 60 days of the completion of RATA.

VII. Specific Requirements

A. Operational Flexibility

Other than the standard conditions (7.1.1, 7.2.1, and 7.2.2), operational flexibility provisions have not been incorporated into this Title V Permit. The applicant did not include any alternative operating scenarios in their Title V Application or request any specific operational flexibility conditions.

B. Alternative Requirements

There are no alternative requirements that need to be incorporated into the Title V Permit.

C. Insignificant Activities

Refer to http://airpermit.dnr.state.ga.us/GATV/default.asp for the Online Title V Application.

Refer to the following forms in the Title V permit application:

- Form D.1 (Insignificant Activities Checklist)
- Form D.2 (Generic Emissions Groups)
- Form D.3 (Generic Fuel Burning Equipment)
- Form D.6 (Insignificant Activities Based on Emission Levels of the Title V permit application)

D. Temporary Sources

Plant Wansley has not requested to operate any temporary sources.

E. Short-Term Activities

Wansley Steam-Electric Generating Plant stated that they have the following short-term activities; painting for maintenance purposes, sand blasting for maintenance purposes, and asbestos removal in accordance with Georgia Rule 391-3-1-.02(9)(b)7. See Form D.5 of the Title V application for a more complete description.

Other than asbestos removal, which is subject to Georgia Rule 391-3-1-.02(9)(b)7, these operations are not subject to any state or federal air quality requirements other than the general provisions of the Georgia Rules for Air Quality Control. The general provisions and the requirement to keep records of the frequency and duration of these activities has been included in Section 7.6 of the permit.

F. Compliance Schedule/Progress Reports

The facility is in compliance with all Air Quality Regulations. Therefore, no compliance schedule or progress reports are necessary.

G. Emissions Trading

This facility is not involved in any emission trading programs besides being part of the Acid Rain Program. This facility is currently operating under a federally enforceable emissions cap. Nothing in this permit shall prohibit this facility from participation in an emissions trading or economic incentives program provided that the permit is amended to include permit terms that ensure that the emissions trades are quantifiable and enforceable.

H. Acid Rain Requirements

This facility is subject to requirements in Title IV of the Clean Air Act. They are subject to 40 CFR 72 (permits), 73 (sulfur dioxide), 75 (monitoring), and 76 (nitrogen oxides). The only affected units at Plant Wansley are the steam generating units. The combustion turbine is not affected because it commenced operation before November 15, 1990 and all simple cycle combustion turbines (regardless of size) that commenced operation before that date are not affected units.

At this time, all Phase II Acid Rain requirements are being incorporated into this Title V Permit. 40 CFR 72.50(a)(1) allows a complete Phase II Permit Application to be attached to the Title V Permit as part of the Permit. Plant Wansley's Phase II Permit Application, as well as the Phase II NOx Compliance Plan and the Phase II NOx Averaging Plan, is attached to the Title V Permit as part of the Permit to ensure that all Acid Rain applicable requirements are incorporated into the Title V Permit.

Specific Monitoring Requirements (40 CFR 75):
The facility is required, under 40 CFR 75, to monitor certain pollutants and parameters, including NOx emissions, SO_2 emissions, CO_2 emissions, flowrate, and heat input. These pollutants and parameters are reported directly to EPA, electronically, on a quarterly basis.

Specific NOx Requirements (40 CFR 76):
Units 1 and 2 are Phase I tangentially fired boilers. The standard Phase I annual average emission limitation for tangentially fired boilers is 0.45 lb/MMBtu. However, these emission units are part of a Phase II NOx averaging plan submitted by Georgia Power Company in accordance with 40 CFR 76.11. Georgia Power has elected to comply with 40 CFR Part 76 by complying with the Phase II NOx averaging plan which is attached as part of the Title V permit.

I. Stratospheric Ozone Protection Requirements

The standard permit condition pursuant to 40 CFR 82 Subpart F has been included in the Title V Permit. These Title VI requirements apply to all air conditioning and refrigeration units containing ozone-depleting substances regardless of the size of the unit or of the source. Since Wansley Steam-Electric Generating Plant has at least some air conditioners, chillers and refrigerators Subpart F is an applicable requirement.

Wansley Steam-Electric Generating Plant does not service motor vehicles, so 40 CFR 82 Subpart B is not applicable.

J. Pollution Prevention

There are no pollution prevention provisions incorporated into this Title V Permit.

K. Specific Conditions

None Applicable.

L. Clean Air Interstate Rule (CAIR) Requirements

Condition 7.15.1 requires the facility to comply with all the applicable requirements in the CAIR permit application. The CAIR permit application is attached as part of this Title V Permit.

Condition 7.15.2 requires the facility to comply with the CAIR facility wide annual NO_X allowance allocations in accordance with 40 CFR 96 and Georgia Rule 391-3-1-.02(12).

The CAIR NO_X allowances have been determined by the Division based on historical operating data for each equipment, and this information is available on EPD's website at http://www.georgiaair.org/airpermit/html/aqrules/caircamr/CAIR.html. The CAIR allowances are not unit specific and the allowances are awarded for the entire facility for each calendar year.

Section 7.15 contains the requirements of CAIR, but this regulation is being replaced by Cross-State Air Pollution Rule (CSAPR). CSAPR is stayed by the federal court on December 30, 2011. Therefore, CAIR will continue to apply to this facility.

VIII. General Provisions

Generic provisions have been included in this permit to address the requirements in 40 CFR Part 70 that apply to all Title V sources, and the requirements in Chapter 391-3-1 of the Georgia Rules for Air Quality Control that apply to all stationary sources of air pollution.

Template Condition 8.14.1 was updated in September 2011 to change the default submittal deadline for Annual Compliance Certifications to February 28.

Addendum to Narrative

The 30-day public review started on April 18, 2012 and ended on March 18, 2012. Comments were received by the Division from Georgia Power and GreenLaw.

Georgia Power Comments

Georgia Power submitted comments in a letter dated May 18, 2012. The following are Georgia Power's comments and EPD responses to those comments:

Comment 1 - Condition 5.2.13

Georgia Power requests to alter the language in this condition such that it is consistent with other Georgia Power facility Title V permits and it accurately reflects the requirements of the material Handling System.

5.2.13 Once each day or portion of each day of operation, the Permittee shall inspect affected emission points in the Material Handling System by conducting a walk-through of the facility and noting the occurrence of the following (a check list or other similar log may be used for this purpose):
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Any emissions unit which exhibits any visible emissions.

b. Any ~~emissions unit that exhibits obvious~~ mechanical failure or malfunction that results in increased air emissions.

EPD Response: The Division agrees, and Condition 5.2.13 is updated.

Comment 2 - Condition 6.2.3

Georgia Power requests to remove the reference to No. 2 fuel oil in this condition as the specified ASTMs refer to No. 2 fuel oil, biodiesel, and biodiesel blends.

6.2.3 The Permittee shall verify that each shipment of fuel oil for combustion in Steam Generating Units 1 and 2 (Emission Unit IDs SG01 and SG02), Start-up Boiler Units 1 and 2 (Emission Unit IDs SB01 and SB02), and Combustion Turbine Unit 5A (Emission Unit ID CT5A) complies with the specifications for fuel oil as defined in ASTM D396, ASTM D975, or ASTM D6751 by obtaining fuel oil supplier certifications. Supplier certifications shall contain the name of the supplier and a statement from the supplier that the oil complies with the specifications for ~~No. 2~~ fuel oil as defined in ASTM D396, ASTM D975, or ASTM D6751. As an alternative to the procedure described above, the Permittee may, for each shipment of fuel oil received, obtain a sample for analysis of the sulfur content. The procedures of ASTM D4057 shall be used to acquire the sample. Sulfur content shall be determined using the procedures of Test Method ASTM D129 or D1552 or by some other test method approved by the US EPA and acceptable to the Division.
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]

EPD Response: The Division agrees, and Condition 6.2.3 is updated.

GreenLaw Comments

GreenLaw submitted comments via email dated May 18, 2012. Please refer to EPD's permit file for the entire copy of the comments received (23 pages) from GreenLaw. The following are GreenLaw's comments (only headings are listed below) and EPD Responses to those comments:

I. Background

EPD Response: Comment so noted.

II. Regulatory Framework

EPD Response: Comment so noted. Regarding their comment that "Permitting authorities should...issue renewed permits prior to expiration of the existing permit," EPD notes that, provided a timely renewal application is submitted, the Permit is not null and void. Expiration of a permit occurs when a Permittee fails to submit a timely application, and EPD fails to issue a renewal permit within 5 years of issuance of existing permit.

Georgia Rule 391-3-1-.03(10)(e)1.(ii) states that "Except as provided under the initial transition plan or under regulations promulgated under Title IV of the federal Clean Air Act, the Director shall take final action on each permit application (including request for permit modification or renewal) within 18 months after receiving a complete application".

III. Address

EPD Response: Section I.A.5 of the narrative states that this facility is located in the $PM_{2.5}$ non-attainment area. This is not a PSD/non-attainment review permit and there is no regulatory requirement in 40 CFR 70 to impose $PM_{2.5}$ emission limit in this Title V Operating Permit.

IV. The Draft Permit is Incomplete

a. Ownership and Operational Units

EPD Response: There is no regulatory requirement in 40 CFR 70 and/or Georgia Rules that precludes EPD from issuing multiple Title V Permits for this Title V site. The Wansley Steam-Electric Generating Plant (AFS No. 149-00001), Southern Power – Wansley Combined-Cycle Generating Plant (AFS No. 149-00011), Oglethorpe Power Corporation – Chattahoochee Energy Facility (AFS No. 149-00006), and the Municipal Electric Authority of Georgia – Wansley Unit 9 (AFS No. 149-00007) are permitted separately. Collectively, they comprise the same Title V site. However, each separate owner/operator is only accountable, for compliance purposes, for the individual electrical generating units that they own or operate.

Ash Processing Facility Site Determination

This separate site determination was made because these two facilities (Georgia Power Company and the ash processing facility) do not meet all three parts of criteria to be considered one source under 40 CFR 70. This site determination is based on EPA's 3 part criteria of (1) same industrial grouping (i.e. SIC code), (2) contiguous or adjacent properties, and (3) common control. The ash processing facility is not operated by Georgia Power, and it is deemed a separate source for purposes of Title V permitting due to the fact that there is no common control between Georgia Power Company and the ash processing facility. A contractual agreement does not invariably equate to "common control".

b. Megawatt Capacity and Heat Input Rates

EPD Response: Maximum heat input rates for each of the two steam generating units and the combustion turbine were included in the narrative for the Title V Renewal Permit No. 4911-149-0001-V-03-0, and the information is as follows:

Emission Unit ID	Emission Unit Description	Maximum Heat Input Capacity (MMBtu/hr)	Fuel Burning Configuration
SG01	Steam Generating Unit 1	9420	Tangentially-fired
SG02	Steam Generating Unit 2	9420	Tangentially-fired
CT5A	Combustion Turbine Unit 5A	904	Normal combustor with water injection

The maximum heat input rates for the two steam generating units and the combustion turbine were also included by the facility in this Title V Renewal Application No. 20541, which is readily available on EPD's website at http://airpermit.dnr.state.ga.us/GATV/GATV/default.asp.

The megawatt capacity can vary depending on a number of factors for each unit. There is no regulatory requirement in 40 CFR 70 to include the maximum heat input rate and megawatt capacity in the Title V Operating Permit.

c. Unclear and Incomplete Permit Terms

EPD Response: Regarding the concern that attachments and documents incorporated by reference are not enforceable, the Division disagrees. The attachments are incorporated by reference (into the permit) in the permit Table of Contents and on the last page of the permit. Note that Attachments A, B and C in the Permit Appendix contain no requirements. The Acid Rain application (Attachment D) is attached as part of the Title V permit in Condition 7.9.8. The CAIR application is attached as part of the permit in Condition 7.15.1.

d. The Permit Must Address, Define and Limit Bypass Operations

EPD Response: Georgia Rule (sss) requirements and Permit Condition No. 3.4.15 clearly state that the facility shall operate the flue gas desulfurization system on steam generating units SG01 and SG02 at all times except for periods as defined in paragraphs a. through i. in Permit Condition No. 3.4.15, which is the same as in paragraph 20 in Georgia Rule (sss). Therefore, Georgia Rule (sss) limits when bypassing the scrubber stack is allowed for steam generating units SG01 and SG02.

It is redundant to define bypass operations in this permit because the facility must comply with Rule (sss) requirements at all times.

V. Emissions Standards

a. Heat Input

EPD Response: There is no regulatory requirement in 40 CFR 70 to include the maximum heat input rate for each steam generating unit as an enforceable condition in the Title V Operating Permit. The emissions from the steam generating unit are limited by the design heat input capacity of the unit, and the facility is required to comply with the emissions limits in Section 3.0 of this Title V Permit.

b. Fuel Flexibility

EPD Response: The facility was constructed before the PSD (40 CFR 52.21) requirements were effective. This is not a PSD permit, and there is no regulatory requirement in 40 CFR 70 to warrant a limit on the usage of fuel in this Renewal Title V Operating Permit.

The commenter is also incorrect in stating that the definition of biomass allows facility to be able to fire municipal solid waste in the steam generating units. Permit Condition 3.2.1c. explicitly states that the definition of biomass does not include municipal solid waste.

Also, Permit Condition 6.2.1 requires the facility to maintain usage records for all types of fuels that are fired, including biomass. Permit Condition 5.2.1 requires the facility to install and operate Continuous Emissions Monitoring Systems (CEMS) for NOx emissions and install and operate Continuous Opacity Monitoring Systems (COMS) for visible emissions on the steam generating units. These continuous monitoring systems will ensure that the facility can comply with the opacity and NOx emissions limits in Section 3.0 of the permit. Compliance with the PM limit is done via performance tests. No additional monitoring and recordkeeping are required under 40 CFR 70 requirements.

Generally, the term "peak load" is understood as the electric generating capacity required by a utility to respond to a maximum level of energy demand over a specified period of time. The term "flame stabilization" is relevant to situations where flame performance in the primary fuel burner becomes unstable and the use of additional igniters or lighters is required to sustain proper combustion.

The term startup is defined in Condition 3.2.2 for burning used oil. Per Georgia Rule 391-3-1-.01(jjj), the term shutdown means the cessation of the operation of a source or facility for any purpose, and this definition will be added in Condition 3.2.2.

c. Particulate Matter

i. The PM limit Should be Significantly Lowered

EPD Response: As stated before, this facility was constructed before the PSD (40 CFR 52.21) requirements were effective. This is not a PSD permit, and there is no regulatory requirement in 40 CFR 70 to include new PM, PM_{10} and $PM_{2.5}$ emissions limits in this Title V Operating Permit.

ii. Coarse and Fine Particle Pollution Should be Limited and Monitored Separately

EPD Response: This facility is not currently subject to any $PM_{2.5}$ emissions standards or limits (applicable requirements). Permit Condition 3.4.1 subjects the two steam generating units to a particulate matter (PM) limit of 0.24 lb/MMBtu heat input, and the method of compliance is via a performance test using Method 5 or Method 17, as applicable, as listed in Condition 4.1.3f. This renewal application did not trigger any requirement to include new separate $PM_{2.5}$ emissions limit.

d. Opacity

EPD Response: This facility was under construction before January 1, 1972, and therefore, the 20 percent opacity limit in Georgia Rule (d) does not apply to the two steam generating units. Permit Condition 3.4.2 limits opacity to 40 percent or less from the two steam generating units. As stated before, there is no regulatory requirement in 40 CFR 70 to include more stringent opacity and PM emissions limits in this Title V Operating Permit.

e. The Draft Permit Should Contain Alternative Sections for CAIR and CSAPR Requirements

EPD Response: On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the Cross-State Air Pollution Rule (CSAPR). Thus, the Clean Air Interstate Rule (CAIR) will continue to apply to this facility. The CAIR NOx allowances are listed in Permit Condition 7.15.2.

When CSAPR becomes effective again and the stay is removed, implementation of CSAPR will likely be done directly by EPA under the Federal Implementation Plan (FIP), and hence no CSAPR requirements are added in this Title V renewal permit. If needed, EPD will incorporate the requirements for CSAPR in a permit amendment in the future.

VI. Excess Emissions

a. Condition 8.14.4 Should Not Include an Affirmative Defense

EPD Response: The excess emissions provisions come directly from Georgia Rule 391-3-1-.02(2)(a)7.

b. If an Affirmative Defense is retained, it must be revised to state that all excess emissions are violations and to retain the availability of injunctive relief

EPD Response: Condition 8.14.4 in this Title V Renewal Permit directly comes from Georgia Rule 391-3-1-.02(2)(a)7.(i). This rule has been an EPA-approved part of the Georgia SIP since 1979 and the courts have specifically upheld the validity of this rule. See e.g., Sierra Club v. Ga. Power Co., 443 F.3d 1346 (11th Cir. 2006) (recognizing the rule as a continuous part of the Georgia SIP). Because it is part of the Georgia SIP, it is entirely appropriate to simply repeat the rule language verbatim in the Plant Wansley Title V permit. The comment's citations appear to be referring to EPA guidance documents regarding the submission of new SIP provisions that regulate startup, shutdown, and malfunction events; however, EPA has specifically acknowledged that such guidance was not intended to affect the validity of existing, approved SIP provisions addressing these events. Therefore, Condition 8.14.4 is appropriate as written.

c. If an Affirmative Defense is retained, it must be revised to provide objective criteria that will allow for practical enforceability

i. Vague and undefined terms must be replaced with specific and objective operational requirements

ii. The Permit must include separate criteria for malfunctions

EPD Response: Please refer to EPD's response to Comment V.b. for definition of startup.

Per Georgia Rule 391-3-1-.01(nn), malfunction means mechanical and/or electrical failure of a process, or of air pollution control process or equipment, resulting in operation in an abnormal or unusual manner. Georgia Rule 391-3-1-.02(2)(a)7 and Condition 8.14.4 do not preclude the use of more specific criteria.

d. Condition 8.14.4 must be revised to address National Emissions Standards for Hazardous Air Pollutants.

EPD Response: Georgia Rule 391-3-1-.02(2)(a)7.(iii) does not mention National Emissions Standards for Hazardous Air Pollutants (NESHAP) in the rule.

Georgia Rule 391-3-1-.02(2)(a)7 shall apply only to those sources which are not subject to any requirement under Georgia Rule 391-3-1-.02(8) – New Source Performance Standards or any requirement of 40 CFR, Part 60, as amended concerning New Source Performance Standards.

Since the EGU Utility MACT (40 CFR 63 Subpart UUUUU) has become effective on April 16, 2012, Condition 3.3.6 is added to include the general requirements for the EGU MACT, as applicable, to the Steam Generating Units SG01 and SG02.

VII. Compliance Assurance Monitoring and Reporting

a. Particulate Matter and Opacity

i. The Frequency of PM Testing Must Be Increased

ii. Parametric Monitoring is Inadequate to Assure Compliance

EPD Response: There is no regulatory requirement in 40 CFR 70 to require this facility to install PM CEMS on Steam Generating Units SG01 and SG02. PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits. No additional PM testing or parametric monitoring is necessary.

b. SO_2

i. The Draft Permit's SO_2 Monitoring and Compliance Provisions Must be Revised to be Consistent with the new 1-hr SO_2 NAAQS

EPD Response: There is no regulatory requirement in 40 CFR 70 to require the facility to conduct a demonstration of source compliance with the new 1-hour SO_2 NAAQS in this Title V Operating Permit.

ii. The Permit's Terms are Inconsistent with Regard to Control Devices Needed for Compliance with Rule (uuu) on a Unit-Specific Basis

EPD Response: For clarity, wording in Condition 5.2.1c. is updated to state "Sulfur dioxide emissions are monitored at both the inlet and outlet of each SO_2 control device".

iii. The Permit Should Clearly Require SO_2 CEMS Operation During All Periods of Operation except CEMS Breakdown and Repair.

EPD Response: EPD's PTM Section 2.125.3(c) and Permit Conditions 3.4.14 and 5.2.14 require the facility to operate the SO_2 CEMS and record data during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments and any period allowed under Georgia Rule 391-3-1-.02(2)(uuu)(4). These Permit Conditions are taken directly from the rules. Therefore, no change will be made to Permit Condition No. 5.2.14.

VIII. Coal Handling System

EPD Response: There is no regulatory requirement in 40 CFR 70 to require the facility to install enclosures, other control devices, and specific dust suppression measures.

Fugitive emissions from the coal handling system must meet the 20 percent opacity limit in Georgia Rule (n). The facility must comply with Permit Condition No. 6.2.4 that requires the facility to maintain a record of all actions taken in accordance with Permit Condition No. 3.4.5 to suppress fugitive dust from the coal handling system (Source Code: CHS), the ash handling system (Source Code: AHS), and the materials handling system (Source Code: MHS).

IX. Greenhouse Gas Monitoring and Reporting

EPD Response: Pages 52-53 of the PSD and Title V Permitting Guidance document cited by the commenter states as following

"It is important to note that GHG reporting requirements for sources established under EPA's final rule for the mandatory reporting of GHGs (40 CFR Part 98: Mandatory Greenhouse Gas Reporting, hereafter referred to as the "GHG reporting rule") are currently ***not included in the definition of applicable requirement in 40 CFR 70.2 and 71.2****. Although the requirements contained in the GHG reporting rule currently are not considered applicable requirements under the title V regulations, the source is not relieved from the requirement to comply with the GHG reporting rule separately from compliance with their title V operating permit. It is the responsibility of each source to determine the applicability of the GHG reporting rule and to comply with it, as necessary. However, since the requirements of the GHG reporting rule are not considered applicable requirements under title V, they do not need to be included in the title V permit".*

There is no regulatory requirement in 40 CFR 70 to include the Mandatory Greenhouse Gas Reporting Requirement in this Title V Operating Permit.

X. Hazardous Air Pollutants

EPD Response: Since the EGU Utility MACT (40 CFR 63 Subpart UUUUU) has become effective on April 16, 2012, Condition 3.3.6 is added to include the general requirements for the EGU MACT to the Steam Generating Units SG01 and SG02. The compliance date for Steam Generating Units SG01 and SG02 is April 16, 2015. Therefore, EPD will add any necessary conditions for EGU MACT in a permit amendment in the future.

EXHIBIT D

http://www.epa.gov/region4/air/permits/georgia.htm

Region 4: Proposed Title V Permits

Last updated on Wednesday, August 22, 2012

You are here: EPA Home Region 4 Air Air Permits Proposed Title V Permits Georgia

Georgia Proposed Title V Permits

The following permits have been submitted to EPA Region 4 as Proposed Title V permits. While EPA has the right to a 45-day review period for all Proposed Title V permits, EPA Region 4 targets only a subset of these permits for comprehensive review. To find out which permits have been targeted for EPA Region 4 review, please contact the Region 4 staff person(s) listed at the bottom of this page.

Title V Permits Undergoing Sequential Review*

State	County	Source Name	PA Permit Number	45-Day Review Ends (sequential)	Petition Deadline
GA	Heard	Georgia Power Company - Plant Wansley	4911-149-0001-V-03-0	7/8/2012	9/6/2012
GA	Heard	Wansley Combined Cycle Generating Plant	4911-149-0011-V-01-0	7/28/2012	9/26/2012
GA	Heard	Municipal Electric Authority of Georgia - Wansley Unit 9	4911-149-0007-V-03-0	8/2/2012	10/1/2012
GA	Chatham	Georgia Power Company - Plant Kraft	4911-051-0006-V-03-0	8/24/2012	10/23/2012
GA	Effingham	Georgia Power Company - Plant McIntosh	4911-103-0003-V-03-0	9/14/2012	11/13/2012

Title V Permits Undergoing Parallel Review**

State	County	Source Name	PA Permit Number	45-Day Review Ends (parallel)	Petition Deadline
GA	Richmond	West Fraser Inc. - Augusta Lumber Mill	2421-245-0047-V-04-0	6/10/2012	9/7/2012
GA	Banks	Chambers R & B Landfill, Inc.	4953-011-0014-V-03-0	6/9/2012	9/7/2012
GA	Greene	Novelis, Inc.	3341-133-0001-V-03-3	6/20/2012	9/17/2012
GA	Banks	Chambers R & B Landfill, Inc.	4953-011-0014-V-03-1	6/24/2012	9/21/2012
GA	Taylor	Veolia ES Taylor County Landfill, LLC	4953-269-0014-V-04-0	6/27/2012	9/24/2012
GA	Cobb	Colonial Pipeline Company - Atlanta Junction	4613-067-0074-V-03-0	7/3/2012	10/1/2012
GA	Barrow	Oak Grove Sanitary/Speedway Landfill	4953-013-0068-V-03-0	7/4/2012	10/1/2012
GA	Jefferson	KaMin - Wrens Calcine Plant	3295-163-0026-V-04-0	7/4/2012	10/1/2012
GA	Clayton	Griffin Industries, Inc. of Georgia	2077-063-0026-V-02-0	7/11/2012	10/8/2012
GA	DeKalb	BP Products North America	5171-089-0130-V-03-0	7/10/2012	10/8/2012
GA	Troup	KIA Motors Manufacturing Georgia, Inc.	3711-285-0084-V-02-0	7/11/2012	10/8/2012
GA	Dougherty	MillerCoors LLC	2082-095-0010-V-04-0	7/15/2012	10/12/2012
GA	Heard	Chattahoochee Energy Facility - Oglethorpe Power	4911-149-0006-V-04-0	7/15/2012	10/12/2012

GA	Fayette	Certainteed Corporation - Peachtree City	2952-113-0013-V-02-0	7/15/2012	10/12/2012
GA	Brantley	Varn Wood Products, LLC	2421-025-0001-V-03-1	7/18/2012	10/15/2012
GA	Atkinson	Langboard MDF	2493-003-0013-V-05-0	7/25/2012	10/22/2012
GA	Dooly	Roseburg Forest Products South LP	2493-093-0022-V-04-0	7/24/2012	10/22/2012
GA	Washington	Thiele Kaolin Company - Sandersville Plant	3295-303-0006-V-03-0	7/24/2012	10/22/2012
GA	Troup	Milliken & Co Live Oak Milstar	2273-285-0032-V-03-0	8/1/2012	10/29/2012
GA	Morgan	Georgia-Pacific Wood Products LLC (Madison Plywood)	2436-211-0013-V-03-0	8/1/2012	10/29/2012
GA	Taylor	Taylor County LFGTE Power Station	4911-269-0016-V-02-3	8/5/2012	11/2/2012
GA	DeKalb	Marathon Petroleum Company LP - Doraville Terminal	5171-089-0120-V-03-0	8/8/2012	11/5/2012
GA	Hall	SAPA Extruder, Inc.	3354-139-0075-V-04-0	8/8/2012	11/5/2012
GA	Effingham	Georgia-Pacific Consumer Products LP (Savannah River Mill)	2621-103-0007-V-04-0	8/8/2012	11/5/2012
GA	Whitfield	The Dow Chemical Company - Polystyrene Plant	3086-313-0106-V-05-0	8/11/2012	11/8/2012
GA	Early	Georgia-Pacific Corporation - Cedar Springs Operations, LLC	2631-099-0001-V-02-8	8/12/2012	11/9/2012
GA	Hall	Milliken & Company - New Holland Plant	2281-139-0046-V-03-0	8/15/2012	11/12/2012
GA	Clayton	Clayton County SR 3 Love Joy Landfill	4953-063-0106-V-03-1	8/22/2012	11/19/2012
GA	Fulton	Georgia Institute of Technology	8221-121-0129-V-02-3	8/22/2012	11/19/2012
GA	Cobb	Marathon Petroleum Company LLC	5171-067-0032-V-05-0	8/22/2012	11/19/2012
GA	Lowndes	Langdale Forest Products Company	2421-185-0009-V-03-0	8/22/2012	11/19/2012
GA	Houston	Anchor Glass Container Corporation	3221-153-0014-V-04-0	8/26/2012	11/23/2012
GA	Newton	FiberVisions Manufacturing Company	2824-217-0020-V-03-0	8/26/2012	11/23/2012
GA	DeKalb	Seminole Road MSW Landfill	4953-089-0299-V-03-0	8/29/2012	11/26/2012
GA	Richmond	PCS Nitrogen Fertilizer L.P.	2873-245-0002-V-03-0	8/29/2012	11/26/2012
GA	Clarke	CII Methane Management II LFGTE Plant	4911-059-0102-V-01	9/5/2012	12/3/2012
GA	Lowndes	Bathcraft, Inc.	3088-185-0073-V-05-0	9/7/2012	12/5/2012
GA	Screven	King America Finishing, Inc.	2261-251-0008-V-04-0	9/12/2012	12/10/2012
GA	Washington	IMERYS Clays, Inc. - Sandersville Calcine Plant	3295-303-0004-V-03-0	9/16/2012	12/14/2012
GA	Baldwin	Triumph Aerostructures, LLC - Vought Aircraft Division	3728-009-0031-V-04-0	9/20/2012	12/18/2012

GA	Newton	Pactiv Corporation - Covington Polystyrene Foam Products	3086-217-0024-V-05-0	9/23/2012	12/21/2012
GA	Appling	Rayonier Wood Products LLC - Baxley Sawmill	2421-001-0005-V-04-0	9/30/2012	12/28/2012
GA	Whitfield	Shaw Industries, Inc. - Plant 81	2273-313-0001-V-03-0	10/3/2012	12/31/2012

* **Sequential Review** means the EPA 45-day review period does not begin until the 30-day public comment period ends. The deadline for the public to petition EPA is 60 days after the EPA 45-day review period ends.

** **Parallel Review** means the EPA 45-day review period runs concurrently with the 30-day public comment period and ends **no earlier** than 15 days after the end of the public comment period. The deadline for the public to petition EPA is 60 days after the EPA 45-day review period ends, calculated as if the Title V permit was under sequential review (i.e., the petition deadline will be the same regardless of whether Parallel or Sequential Review is followed.)

For information about the contents of this page please contact Andy Porter.

EXHIBIT E

IN THE MATTER OF THE DRAFT TITLE V PERMIT FOR RRI ENERGY MID ATLANTIC POWER HOLDINGS LLC SHAWVILLE GENERATING STATION DRAFT TITLE V/STATE OPERATING PERMIT IN CLEARFIELD COUNTY, PA ISSUED BY THE PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION	))))))))))	ID NO. 17-00001

DECLARATION OF

RANAJIT (RON) SAHU

(1) I, Ranajit Sahu, am an environmental engineer with more than 18 years of experience in program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; and multimedia environmental regulatory compliance and permitting, among other things. In addition to my consulting work for private industry on New Source Review and other matters, I have testified on behalf of the United States in several New Source Review enforcement actions in federal court.

(2) I have a B.S., M.S., and Ph.D. in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute

of Technology (Caltech) in Pasadena, California. My research specialization was in the combustion of coal and, among other things, understanding air pollution aspects of coal combustion in power plants.

(3) A copy of my current resume is provided in Attachment A.

(4) It is my understanding that the current matter pertains to the emissions of a class of air pollutants known as particulate matter from the coal-fired boilers at the Shawville Generating Station (SGS), owned by RRI Energy Mid-Atlantic Power Holdings LLC. SGS consists of four boilers, numbered Units 1 through 4. Units 1 and 2 (1954) are dry bottom, front wall-fired balanced draft sub-critical boilers fired using bituminous coal and No. 2 oil. Units 3 (1959) and 4 (1960) are tangential fired boilers firing the same fuels.

(5) Among other pollutants, coal-fired power plant boilers such as the Shawville Units 1 through 4, can emit particulate matter (PM) or dust of varying size and chemical composition. Total suspended particulate (TSP) matter will be referred to simply as PM. Particles with an aerodynamic diameter[1] of 10 micrometers (or microns) or smaller will be denoted as PM10. Particles with aerodynamic diameters 2.5 micrometers or smaller

[1] In air pollution control, it is necessary to use a particle size definition that directly relates to how the particle behaves in a fluid such as air. The term "aerodynamic diameter" has been developed by aerosol physicists in order to provide a simple means of categorizing the sizes of particles having different shapes and densities with a single dimension. The **aerodynamic diameter** is the diameter of a spherical particle having a density of 1 gm/cm^3 that has the same inertial properties [i.e. terminal settling velocity] in the gas as the particle of interest. See http://www.epa.gov/apti/bces/module3/diameter/diameter.htm.

will be denoted as PM2.5. By comparison, the diameter of typical human hair is around 70 to 100 micrometers.

(6) Particles collected, in any of the size classes above, are also classified into two fractions – namely the filterable and the condensable portions. Filterable particles are those that are present in a form suitably collected by a filter present in the exhaust gas path. Condensable particles are those that may be present in the vapor phase at the exhaust gas temperature but which can condense into particles at the lower temperatures present in the ambient air. Together the filterable and condensable fractions are sometimes referred to as the "total" in any size class. Finally, these total (filterable plus condensable) fractions are sometimes referred to as the primary particulates since they are directly emitted by the source boiler. Other particles that can form in the atmosphere resulting from gaseous emissions from the boiler are sometimes referred to as secondary particles.

(7) Primary particles are emitted because the combustion of coal in a boiler results in the formation of flyash, which, in turn, is due to the presence of mineral matter in coal that cannot be burned (unlike the carbon which does burn in the boiler). Some of the mineral matter transforms to bottom ash, which is not entrained in the combustion exhaust air and drops down to the bottom in the boiler. But, typically, a significant fraction (greater than 50%) of the ash is emitted from the boiler as fly ash.

(8) I have been asked to provide an opinion, in general, on how emissions of primary, filterable PM, PM10, and PM2.5 can vary from a coal-fired power plant boiler, such as any of the Shawville units, equipped with electrostatic precipitators (ESP).

(9) SGS Units 1 and 2 are each equipped with 2 ESPs, while SGS Units 3 and 4 are each equipped with 4 ESPs. All of the ESP units are “cold” side units meaning that they are located after the respective combustion air preheaters.

(10) Without any air pollution controls, the bulk of the fly ash containing filterable PM/PM10/PM2.5 would simply be emitted to the atmosphere from the boiler. However, almost all boilers use particulate control devices to prevent or minimize that. The vast majority of these are either fabric filters (typically the newer boilers) or ESPs.

(11) The basic principle of operation of ESPs is as follows. A high voltage corona discharge is used to electrically charge the flyash particles. The charged particles then migrate in an applied electric field to the collection electrode where they accumulate. For example, negatively charged particles migrate to the positive electrode. The collected particles are subsequently removed by mechanical action (or rapping) where they fall into collection hoppers for disposal.

(12) There are two major charging processes, field charging and diffusion charging. Field charging refers to the bombardment of the particles by negative ions, moving under the influence of the electric field. The charge acquired depends on the charging field, the surface area and dielectric properties of the particle, and the time available for charging. This is the most important means of charging particles greater than 1 micrometer in aerodynamic diameter. Diffusion charging results from the thermal or random motion of ions causing them to diffuse through the surrounding gas. As particles collide with the diffusing ions, charge is transferred. The charge attained in this case depends on particle size, gas characteristics, gas temperature, and the time available for charging. Diffusion

charging is most significant for particles smaller than 0.1 micrometers in aerodynamic diameter. Since both processes occur simultaneously, there is a relative minimum in combined efficiency for both processes for particle diameters around 1 micrometer in aerodynamic diameter.

(13) The overall efficacy of an ESPs is expressed in terms of its "efficiency" which is defined as the ratio of the mass of particles removed by the ESP to the mass of particles entering the ESP.

(14) The emissions of PM/PM10/PM2,5 can vary from coal-fired boilers because they depend on numerous factors. While a complete and exhaustive listing of every single factor that can affect emissions of these pollutants would be almost impossible to compile, based on my experience the following factors should be considered. I have grouped them into properties of the fuel (coal), properties of the flyash particles themselves, and factors affecting ESP performance.

(15) Collectively, all of these factors, their interactions, and their variation with time, will affect how much primary, filterable PM/PM10/PM2,5 is actually emitted. In addition, there are numerous additional factors that affect the accuracy and variability of how much PM/PM10/PM2.5 are measured. Thus, the observed variability of these emissions is a combination of the factors listed below and the factors associated with the measurement process.

(16) The more important properties of the coal that can effect PM/PM10/PM2.5 emissions are:

• Mineral matter or ash quantity. Lower the mineral matter content, less particulate emissions are produced. In addition, reduction in ash loading tends to improve ESP efficiency.

• Fly-ash electrical resistivity. Since the collection of the particles at the later ESP depends on the ability of the particles to be electrically charged, their electrical resistivity plays an important role. If the resistivity is too low, particles can lose their charge either before collection or they may be released back into the exhaust gas stream after collection. If the resistivity is too high, the collected particles cannot easily be dislodged from the ESP collecting electrode and this reduces ESP efficiency.

• Coal moisture content. Coal moisture content can affect the exhaust gas flow rate and temperature, both of which will affect collection efficiency.

• Ash chemical composition. The particle electrical resistivity as well as the ability of various exhaust gas components to condense (on other ash particles), depends on the chemical composition of the coal and the mineral matter.

• Ash particle size. Migration velocity and therefore particle collection rates decrease in proportion to the size of the particle (Darby 1983; Wibberley and Wall 1985).

(17) Properties of the particles themselves that can effect PM/PM10/PM2.5 emissions are as follows:

• Electrical characteristics. Particle electrical characteristics are determined by the resistivity of the fly-ash after it has formed an ash layer on the collecting surface. If the resistance level is high, the corona current passing through the ash layer must be generally reduced or back corona effects will reduce the performance of the ESP. The range of resistivity is affected by the chemistry of the ash, moisture in the flue gas, levels of other chemicals such as sulfur trioxide and flue gas temperature.

• Size distribution. Dust collection is affected by the particle size due to the two mechanisms of particle charging described earlier.

• Migration velocity. The speed of the movement of charged particles to the collection electrodes is denoted by the electrostatic migration velocity which, in turn, depends on a number of assumptions concerning the flow and nature of the charging mechanism. The effective migration velocity is an indication of a precipitator's ability to collect a specific sample of PM/PM10/PM2.5 at a specific operating condition. The effective migration velocity varies with particle size.

• Particle shape. Particle shape can influence collection efficiency because shape affects the ability of the particle to be charged as well as the migration properties of the particles. Angular particles tend to interlock in the collected layer on the ESP plates and be rapped/removed in a more coherent agglomerate, resulting in less re-entrainment than spherical particles.

• Particle cohesivity. Particle cohesivity (the ability to adhere to one another) on the plates of an ESP is also an important factor in relation to re-entrainment. The more cohesive the particles, the less likely they will be re-entrained into the gas stream.

• Unburnt carbon content. The unburnt carbon content for a particle is a reflection of the coal reactivity as well as the combustion conditions. High levels of unburnt carbon (which depend on combustion conditions) can affect particle resistivity.

(18) In addition to the above, important factors that affect the overall collection efficiency of an ESP include:

• Particle residence time. The time available to charge and collect a dust particle. In turn, this depends on particle shape and size. It also depends on specific geometrical aspects such as the position of the particle in relation to the electrical field at the entry to the ESP.

• Gas flow and particle concentration uniformity. If the exhaust gas flow entering the ESP is not uniform, it will adversely affect the residence time and therefore the efficiency.

• ESP Power. The overall electrical energy available to charge the ash.

• Electrode cleaning. The effectiveness of dust removal from electrodes within the ESP.

• Sneakage. This refers to ash bypassing the electrical sections of the ESP, i.e. between discharge and collection electrodes, and thus escaping capture.

• Back corona. This occurs when the ash layer on the collector surface has reached a level of resistivity that the accumulated layer breaks down and produces a flow of positive ions back towards the negative high voltage discharge electrode.

• Re-entrainment of particles. This refers to the reintroduction of particles to the gas stream from the discharge electrodes and collecting surfaces during rapping. It can also result from gas sweepage, when gas that bypasses the treatment zone of the ESP, disturbs collection zones such as hoppers.

(19) Of course, in addition to the factors listed above, the overall age, condition, deterioration, maintenance and other factors of the boilers and the ESPs will also affect the emissions of these pollutants.

(20) Given these numerous factors discussed above that can, singly and in combination, affect the emissions of these pollutants from each of the Shawville boilers, the emissions of PM/PM10/PM2.5 will likely be variable, and significantly so. For example, in my experience, it is not uncommon for such variability to be multiple-times or even an order or magnitude different between the typical three back-to-back hourly test runs in a stack test. Thus, it is highly unlikely that an occasional measurement (such as a stack test) will accurately be able to capture such variability. A stack test is a snap-shot in time and cannot possible provide any information for the periods between tests. Thus, continuous measurements of filterable PM, using CEMS that

are now available, are the proper means of accurately measuring such emissions. Such continuous measurements, done properly, will capture the variability of these emissions over time and therefore provide a more accurate record of the emissions from the Shawville units.

I declare under penalty of perjury that the foregoing is true and correct.

Ranajit Sahu

Executed on February 14, 2011 in Alhambra, CA

RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)

CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES

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e-mail (preferred): sahuron@earthlink.net

EXPERIENCE SUMMARY

Dr. Sahu has over twenty one years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over nineteen years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past seventeen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

Dr. Sahu's experience includes various projects in relation to industrial waste water as well as storm water pollution compliance include obtaining appropriate permits (such as point source NPDES permits) as well development of plans, assessment of remediation technologies, development of monitoring reports, and regulatory interactions.

In addition to consulting, Dr. Sahu has taught and continues to teach numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater and at USC (air pollution) and Cal State Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

"Thermodynamics and Heat Transfer," Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

"Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2011.

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada," with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

"The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants," with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

Annex A

Expert Litigation Support

1. Matters for which Dr. Sahu has have provided depositions and affidavits/expert reports include:

(a) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill

(b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

(c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the US Department of Justice in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (S.D. Ohio).

(d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the US Department of Justice in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (S.D. Ill.).

(e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the US Department of Justice in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (M.D.N.C.).

(f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the US Department of Justice in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (S.D. Ohio).

(g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

(h) Expert reports and depositions (10/31/2005 and 11/1/2005) on behalf of the US Department of Justice in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (E.D. KY).

(i) Deposition (10/20/2005) on behalf of the US Department of Justice in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (S.D. Ind.).

(j) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

(k) Expert report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

(l) Expert report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

(m) Expert report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

(n) Expert report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

(o) Expert testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

(p) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

(q) Expert reports and deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(r) Expert reports and pre-filed testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

(s) Expert reports and deposition (October 2007) on behalf of MTD Products Inc., in connection with General Power Products, LLC v MTD Products Inc., 1:06 CVA 0143 (S.D. Ohio, Western Division)

(t) Experts report and deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

(u) Expert reports, affidavit, and deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

(v) Affidavit/Declaration and Expert Report on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6, under construction in North Carolina.

(w) Dominion Wise County MACT Declaration (August 2008)

(x) Expert Report on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis (June 13, 2008).

(y) Expert Report on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas (February 2009).

(z) Expert Report and deposition on behalf of MTD Products, Inc., in the matter of Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al. (June 2009, July 2009).

(aa) Expert Report on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina (August 2009).

(bb) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

(cc) Expert Report (August 2009) and Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(dd) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (October 2009).

(ee) Expert Report, Rebuttal Report (September 2009) and Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(ff) Expert report (December 2009), Rebuttal reports (May 2010 and June 2010) and depositions (June 2010) on behalf of the US Department of Justice in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(gg) Prefiled testimony (October 2009) and Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(hh) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

(ii) Written Direct Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(jj) Expert report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(kk) Declaration (August 2010) on behalf of the US EPA and US Department of Justice in the matter of DTE Energy Company, Detroit, MI (Monroe Unit 2).

(ll) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

(mm) Expert Report (August 2010) and Rebuttal Expert Report (September 2010) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(nn) Written Direct Expert Testimony (August 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(oo) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(pp) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of Public Service Company of New Mexico (PNM)'s Mercury Report for the San Juan Generating Station, CIVIL NO. 1:02-CV-0552 BB/ATC (ACE). US District Court for the District of New Mexico.

(qq) Comment Report (October 2010) on the Draft Permit Issued by the Kansas DHE to Sunflower Electric for Holcomb Unit 2. Prepared on behalf of the Sierra Club and Earthjustice.

(rr) Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(ss) Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(tt) Comment Report (December 2010) on the Pennsylvania Department of Environmental Protection (PADEP)'s Proposal to grant Plan Approval for the Wellington Green Energy Resource Recovery Facility on behalf of the Chesapeake Bay Foundation, Group Against Smog and Pollution (GASP), National Park Conservation Association (NPCA), and the Sierra Club.

(uu) Written Expert Testimony (January 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

2. Occasions where Dr. Sahu has provided oral testimony <u>at trial or in similar proceedings</u> include the following:

(vv) In February, 2002, provided expert witness testimony on emissions data on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

(ww) In February 2003, provided expert witness testimony on regulatory framework and emissions calculation methodology issues on behalf of the US Department of Justice in the Ohio Edison NSR Case in the US District Court for the Southern District of Ohio.

(xx) In June 2003, provided expert witness testimony on regulatory framework, emissions calculation methodology, and emissions calculations on behalf of the US Department of Justice in the Illinois Power NSR Case in the US District Court for the Southern District of Illinois.

(yy) In August 2006, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Western Greenbrier) on behalf of the Appalachian Center for the Economy and the Environment in West Virginia.

(zz) In May 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Thompson River Cogeneration) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) before the Montana Board of Environmental Review.

(aaa) In October 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Sevier Power Plant) on behalf of the Sierra Club before the Utah Air Quality Board.

(bbb) In August 2008, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Big Stone Unit II) on behalf of the Sierra Club and Clean Water before the South Dakota Board of Minerals and the Environment.

(ccc) In February 2009, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Santee Cooper Pee Dee units) on behalf of the Sierra Club and the Southern Environmental Law Center before the South Carolina Board of Health and Environmental Control.

(ddd) In February 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (NRG Limestone Unit 3) on behalf of the Sierra Club and the Environmental Integrity Project before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(eee) In November 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(fff) In February 2010, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (White Stallion Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(ggg) In September 2010 provided oral trial testimony on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(hhh) Oral Direct and Rebuttal Expert Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(iii) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(jjj) Oral Testimony (October 2010) regarding mercury and total PM/PM10 emissions and other issues on a remanded permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(kkk) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(lll) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(mmm) Deposition (December 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(nnn) Deposition (February 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(ooo) Oral Expert Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).