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BEFORE THE ADMINISTRATOR  
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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An Operating Permit for the McIntosh  
Steam-Electric Generating Plant, Effingham  
County, Georgia.

Source I.D. 04-13-103-00003

Permit No. 4911-103-0003-V-03-0

Proposed by the Georgia  
Environmental Protection Division.

Petition No. V-2012-\_\_\_\_\_

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

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Pursuant to Clean Air Act § 505(b)(2) and 40 CFR § 70.8(d), Sierra Club<sup>1</sup> (“Petitioner”) petitions the Administrator of the United States Environmental Protection Agency (“U.S. EPA” or “EPA”) to object to a proposed Title V Operating Permit for the McIntosh Steam-Electric Generating Plant (“McIntosh”), Permit Number 4911-103-0003-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.

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<sup>1</sup> 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 McIntosh 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.

Petitioner provided comments to the GEPD on the draft permit. A copy of Petitioner's 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 Petitioner's knowledge, EPA has not yet objected to the proposed Permit. See <http://www.epa.gov/region4/air/permits/#Part70> (last visited November 13, 2012).

This Petition is filed within 60 days following the end of U.S. EPA's 45-day review period, as required by Clean Air Act ("CAA") § 505(b)(2).<sup>2</sup> 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 requirements or requirements under this part."). "Applicable requirements" include, *inter alia*, any provision of the Georgia State Implementation Plan ("SIP"), including any term or condition of any preconstruction permit, 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

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<sup>2</sup> EPA's forty-five (45) day comment period expired on September 14, 2012. The public's time for petitioning the Administrator extends through, at least, November 13, 2012. EPA's List of Georgia Proposed Title V Permits, *available at* <http://www.epa.gov/region4/air/permits/georgia.htm> (last accessed November 9, 2012) (attached at Exhibit D)

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-two-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 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.
3. 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 FOR PARTICULATE MATTER.**

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 revise it to include sufficient 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 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). “[W]here 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. . . .’” *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").

However, the Permit's condition governing PM monitoring is not sufficient to assure compliance with hourly PM limitations. Demonstration of compliance with PM limits via stack test every 12 to 13 months, or perhaps 24 months under certain conditions, is insufficient to assure continuous compliance with hourly PM limitations. Permit at 4.2.1.a. The PM emission standard for McIntosh is derived from Georgia Comp. R. & Regs. r. 391-3-1-.02(2)(d)1(ii), and prohibits the emission of "particulate matter in excess of 0.18 lb/MMBtu" from any steam generating unit. Permit at 3.4.1; Georgia Comp. R. & Regs. r. 391-3-1-.02(2)(d)2(ii) (applicable to

sources constructed prior to 1972). 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(ii); 40 C.F.R. § 70.6(a)(3)(i)(B).

The monitoring frequency, requiring demonstration of compliance with PM limits via stack test every 12 to 13 months, or perhaps 24 months under certain conditions, is insufficient to assure continuous compliance with hourly PM limitations. Permit at 4.2.1.a. Neither the Permit, Narrative, nor GEPD’s responses to Petitioner’s comments, provide adequate rationale as to why GEPD thinks that the chosen method is sufficient to assure compliance. Permit; Amended Narrative at Addendum 9. Rather GEPD states that there are no requirements to install CEMS and that continuous opacity monitoring systems (“COMS”) are sufficient.<sup>3</sup> Amended Narrative at Addendum 9.

As discussed above, EPA has already found that 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

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<sup>3</sup> Although EPD attempts to provide an explanation as to why it feels that COMS are sufficient by attempting to correlate between opacity and PM, this explanation is inadequate for a number of reasons. For example, EPD relies on correlations between opacity and PM, which can differ based on load; the explanation does not explain whether the stack tests it used were across a range of loads. *See* Narrative at 9. Further, EPD it is unclear whether EPD repeats the correlation analysis during every stack test, which is important to assure that those correlations are still accurate. *Id.*

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.

Additionally, 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 McIntosh strongly indicate the necessity for continuous monitoring. The facility employs electrostatic precipitators (“ESPs”) to control particulate matter, which can be 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 F).<sup>4</sup> 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.

Additionally, 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*

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<sup>4</sup> 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 Permit.

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 McIntosh.

## **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, 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.”

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. Since the Permit was issued on September 25, 2012, the permit must include provisions incorporating this rule.

GEPD's response is inadequate to address the new EGU MACT. GEPD did add Condition 3.3.9 that makes a generic reference to the EGU MACT. Amended Narrative at Addendum 9. Petitioner was obviously not able to comment on Condition 3.3.9 during the comment period because it did not exist at that point. Having now reviewed Condition 3.3.9, we have determined that EPA should object to the Permit because it fails to include the specific requirements of the EGU MACT, and fails 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 AND ASH HANDLING SYSTEMS.**

Petitioner's comments pointed out that the 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 from the coal and ash handling systems. Comments at section VII. GEPD's response to these comments only addresses requirements to record actions taken, but does not address Petitioner's concern that the 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 3.4.4.

The Permit subjects the coal handling systems 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. Permit at condition 3.3.4. 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 3.4.4. 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 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 Petitioner 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 Petitioner's members. Others result in illegal monitoring and reporting that make it difficult for Petitioner to monitor and enforce air pollution limits applicable to the plant.

Dated this 13th day of November, 2012.

Attorneys for Petitioner,

A handwritten signature in black ink that reads "Ashten Bailey". The signature is written in a cursive, flowing style.

Ashten Bailey

GREENLAW  
State Bar of Georgia Building  
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 Petitioner's Petition to the United States Environmental Protection Agency regarding the McIntosh Power Plant, Permit No. 4911-103-0003-V-03-0.

To Administrator Jackson via electronic mail: 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: 13th day of November, 2012



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Ashten Bailey



# EXHIBIT A

# Part 70 Operating Permit

**Permit Number:** 4911-103-0003-V-03-0      **Effective Date:** September 25, 2012

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

**Facility Address:** 981 Old Augusta Road  
Rincon, Georgia, 31326 (Effingham County)

**Mailing Address:** 981 Old Augusta Road Central/P.O. Box 2507  
Rincon, Georgia, 31326

**Parent/Holding Company:** Southern Company / Georgia Power

**Facility AIRS Number:** 04-13-103-00003

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 one steam electric generating unit and eight (8) simple cycle combustion turbines.

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-20540 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 **55** pages.

[Signed]

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Director  
Environmental Protection Division

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**PART 1.0 FACILITY DESCRIPTION**

**1.1 Site Determination**

The McIntosh Steam – Electric Generating Plant (AFS No. 103-00001) and the McIntosh Combined-Cycle facility (AFS No. 103-00014) comprise the same Title I and Title V site.

**1.2 Previous and/or Other Names**

The facility is commonly known and referred to as Plant McIntosh. It was formerly known as Effingham Station (before 1983).

**1.3 Overall Facility Process Description**

Plant McIntosh burns fossil fuel to generate electricity. This facility includes one steam electric generating unit which primarily burns coal and eight (8) simple cycle combustion turbines which primarily burn natural gas. The steam generating unit exhausts through one 400-foot stack, designated as Source 1. Each combustion turbine has its own exhaust which is 64-feet tall.

**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.

## Title V Permit

### 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	391-3-1-.02(2)(b) 391-3-1-.02(2)(d) 391-3-1-.02(2)(g) 391-3-1-.02(2)(sss) 40 CFR 63 Subpart A 40 CFR 63 Subpart UUUUU 40 CFR 64 Acid Rain	3.2.1, 3.2.2, 3.3.9, 3.4.1, 3.4.2, 3.4.3, 3.4.9, 4.2.1, 5.2.1, 5.2.3, 5.2.12, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.18, 6.2.1, 6.2.2, 6.2.3, 6.2.4, 6.2.5, 6.2.7, 7.9.1 through 7.9.8	EP01	ESP
CT01	Combustion Turbine Unit #1	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(g) 40 CFR 60 Subpart A 40 CFR 60 Subpart GG 40 CFR 63 Subpart A 40 CFR 63 Subpart YYYY 40 CFR 64 Acid Rain	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.4, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	WI1	Water Injection
CT02	Combustion Turbine Unit #2	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.5, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	WI2	Water Injection
CT03	Combustion Turbine Unit #3	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.6, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	WI3	Water Injection
CT04	Combustion Turbine Unit #4	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.7, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	WI4	Water Injection

## Title V Permit

McIntosh Steam – Electric Generating Plant

Permit No.: 4911-103-0003-V-03-0

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
CT05	Combustion Turbine Unit #5	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.8, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.1, 6.2.3, 6.2.6, 7.9.1 through 7.9.8	WI5	Water Injection
CT06	Combustion Turbine Unit #6	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.9, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	WI6	Water Injection
CT07	Combustion Turbine Unit #7	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.10, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.1, 6.2.3, 6.2.6, 7.9.1 through 7.9.8	WI7	Water Injection
CT08	Combustion Turbine Unit #8	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.11, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.1, 6.2.3, 6.2.6, 7.9.1 through 7.9.8	WI8	Water Injection
CHS	Coal Handling System	391-3-1-.02(2)(n) 40 CFR 60 Subpart A 40 CFR 60 Subpart Y	3.3.5, 3.4.4, 6.2.2, 6.2.3	None	NA
AHS	Ash Handling System	391-3-1-.02(2)(n)	3.4.4, 3.4.5, 6.2.2, 6.2.3	None	NA
SB01	Start-Up Boiler Unit 1	391-3-1-.02(2)(b) 391-3-1-.02(2)(d) 391-3-1-.02(2)(g) 40 CFR 63 Subpart A 40 CFR 63 Subpart DDDDD	3.2.5, 3.3.8, 3.4.6, 3.4.7, 3.4.8, 5.2.18, 6.2.3	None	NA

\* 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 unit (Emission Unit ID SG01) except for the following:  
[391-3-1-.03(2)(c)]

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



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- 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.

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- 3.2.2 The Permittee shall not burn used oil in any steam generating unit (Emission Unit ID SG01) 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 shall be defined as 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 natural gas, No. 2 fuel oil, biodiesel, or biodiesel blends in the combustion turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08).  
[40 CFR 52.21(j), 391-3-1-.03(2)(c) and 391-3-1-.02(2)(g)2 subsumed]
- 3.2.4 The Permittee shall limit the burning of fuel(s) in each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) such that the maximum annual heat input from the burning of all such fuel(s) in each turbine does not exceed  $2.2 \times 10^{12}$  Btu. For purposes of this condition, the maximum annual heat input of the fuel oil burned in a turbine shall be calculated by multiplying the annual fuel oil (in gallons) consumed by the turbine, as measured by the fuel oil measurement device required by Condition 5.2.1, by 137,000 Btu per gallon. The maximum annual heat input of the natural gas burned in a turbine shall be calculated by multiplying the annual natural gas (in cubic feet) consumed by the turbine, as measured by the natural gas measurement device required by Condition 5.2.1, by 1022 Btu per cubic foot.  
[40 CFR 52.21(j)]
- 3.2.5 The Permittee shall not fire any fuel other than No. 2 fuel oil, biodiesel, or biodiesel blends in the start-up boiler (emission unit ID SB01).  
[391-3-1-.03(2)(c)]

**3.3 Equipment Federal Rule Standards**

3.3.1 The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08), when burning fuel oil in the turbine, any gases which:  
[40 CFR 52.21(j) and 40 CFR 60.332(a) subsumed]

a. Contain nitrogen oxides in excess of that allowed by the following equation:

$$STD = 0.0042 + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis)

F = NOx emission allowance for fuel-bound nitrogen defined by the following table:

Fuel-bound nitrogen (% by wt.)	F (NOx % by volume)
N < or = 0.015	0
0.015 < N < or = 0.06	0.04(N)
N > 0.06	0.0024

where: N = the nitrogen content of the fuel (% by wt.)

b. Contain carbon monoxide in excess of the following rates:

- i. 9 ppmvd at a load factor of 100% load or greater.
- ii.  $CO = -4.72 \times (LF\%) + 481$ ; for load factors greater than or equal to 75% load and less than 100% load.
- iii.  $CO = -8.92 \times (LF\%) + 796$ ; for load factors greater than or equal to 50% load and less than 75% load.
- iv. 350 ppmvd at loads below a load factor of 50% load.

Where CO equals the allowable carbon monoxide emission rate in ppmvd and LF% equals the load factor percentage with 100 corresponding to 100% load, defined as the maximum load achieved during the testing of the unit.

- c. Contain particulate matter in excess of 0.012 pound per million Btu heat input.
- d. Contain volatile organic compounds, as carbon, in excess of 30 ppm when the load factor is less than 75% and 11 ppm when the load factor is equal to or greater than 75%.
- e. Exhibit greater than 10 percent opacity.

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- 3.3.2 The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08), when burning natural gas in the turbine, any gases which:  
[40 CFR 52.21(j)]
- a. Contain nitrogen oxides in excess of 25 ppmvd at 15 percent oxygen.
  - b. Contain carbon monoxide in excess of the following rates:
    - i. 9 ppmvd at a load factor of 100% load or greater.
    - ii.  $CO = -4.72 \times (LF\%) + 481$ ; for load factors greater than or equal to 75% load and less than 100% load.
    - iii.  $CO = -8.92 \times (LF\%) + 796$ ; for load factors greater than or equal to 50% load and less than 75% load.
    - iv. 350 ppmvd at loads below a load factor of 50% load.

Where CO equals the allowable carbon monoxide emission rate in ppmvd and LF% equals the load factor percentage with 100 corresponding to 100% load, defined as the maximum load achieved during the testing of the unit.
  - c. Contain particulate matter in excess of 0.006 pound per million Btu heat input.
  - d. Contain volatile organic compounds, as carbon, in excess of 30 ppm when the load factor is less than 75% and 11 ppm when the load factor is equal to or greater than 75%.
  - e. Exhibit greater than 10 percent opacity.
- 3.3.3 The Permittee shall not burn in any combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) any fuel oil which contains sulfur in excess of 0.5 percent by weight.  
[40 CFR 52.21(j) and 40 CFR 60.334(j)(2) subsumed]
- 3.3.4 Emission Units CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08 shall comply with all applicable requirements in 40 CFR 60 - Standards of Performance for New Stationary Sources, Subpart A - General Provisions and 40 CFR 60 - Standards of Performance for New Stationary Sources, Subpart GG – Standards of Performance for Stationary Gas Turbines.  
[40 CFR 60 Subpart A and 40 CFR 60 Subpart GG]
- 3.3.5 The percent opacity from the coal handling system (Emission Unit ID CHS) shall not equal or exceed 20 percent.  
[40 CFR 60.252(c), 391-3-1-.02(2)(n)2 subsumed]

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- 3.3.6 The annual average sulfur content of the fuel oil burned in the combustion turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) shall not exceed 0.05 percent by weight.  
[40 CFR 52.21]

$$\text{AAS} = [(\sum_{i=1,n}(\text{DS}_i * \text{DOF}_i)) / \sum_{i=1,n}(\text{DOF}_i)]$$

Where:

AAS = annual average sulfur content (% by weight)

n = total number of days per calendar year during which fuel oil is burned in one or more turbines

DS = daily sulfur content (% by weight) of the fuel oil burned in the turbine(s)

DOF = total gallons of fuel oil burned in the turbine(s) during the day

- 3.3.7 The Permittee shall comply with all applicable requirements of Federal Rule 40 CFR 63 Subpart A – General Provisions and Federal Rule 40 CFR 63 Subpart YYYY – NESHAP for Stationary Combustion Turbines, for the operation of Combustion Turbine Units CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08. Stationary combustion turbines constructed or reconstructed prior to January 14, 2003 do not have to meet the requirements of 40 CFR 63 Subpart YYYY or Subpart A.  
[40 CFR 63.6090(b)(4)]

- 3.3.8 The Permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart DDDDD - "Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters" for operation of the startup boiler (Emission Unit ID SB01).  
[40 CFR 63 Subpart DDDDD]

- 3.3.9 The Permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart UUUUU - "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" for operation of the steam generating unit (Emission Unit ID SG01).  
[40 CFR 63 Subpart UUUUU]

### 3.4 Equipment SIP Rule Standards

- 3.4.1 The Permittee shall not discharge or cause the discharge into the atmosphere from the steam generating unit (Emission Unit ID SG01) any gases which contain particulate matter in excess of 0.18 lb/mmBtu heat input.  
[391-3-1-.02(2)(c), 391-3-1-.02(2)(d)1(ii) (subsumed)]

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- 3.4.2 The Permittee shall not discharge or cause the discharge into the atmosphere from the steam generating unit (Emission Unit ID SG01) 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 the steam generating unit (Emission Unit ID SG01) that contains greater than 3.0 percent sulfur, by weight.  
[391-3-1-.02(2)(g)2]
- 3.4.4 The Permittee shall take all reasonable precautions with the coal handling system (Emission Unit ID CHS) and the ash handling system (Emission Unit ID AHS) to prevent fugitive dust from these operations from becoming airborne.  
[391-3-1-.02(2)(n)1]
- 3.4.5 The percent opacity from the ash handling system (Emission Unit ID AHS) shall not equal or exceed 20 percent.  
[391-3-1-.02(2)(n)2]
- 3.4.6 The Permittee shall not cause, let, suffer, permit or allow the emission of fly ash and/or other particulate matter from the startup boiler (Emission Unit ID SB01) in amounts equal to or exceeding the allowable rate calculated  $P = 0.5(10/R)^{0.5}$   
[391-3-1-.02(2)(d)2(ii)]

Where:

P = allowable weight of emissions of fly ash and/or other particulate matter in pounds per million BTU heat input

R = heat input of fuel-burning equipment in million BTU per hour

- 3.4.7 The Permittee shall not cause, let, suffer, permit or allow the emissions from the startup boiler (Emission Unit ID SB01), 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)3, 391-3-1-.02(2)(b)1 subsumed]
- 3.4.8 The Permittee shall not burn fuel containing more than 2.5 percent sulfur, by weight, in the startup boiler (Emission Unit ID SB01).  
[391-3-1-.02(2)(g)2]
- 3.4.9 Effective January 1, 2018, the Permittee shall evaluate the economic and technical feasibility of additional mercury controls on the steam generating unit (Emission Unit ID SG01) and submit a report on the findings to the Division no later than September 1 of the calendar year following the calendar year that the annual heat input of the steam generating unit (Emission Unit ID SG01) exceeds 14,557,638 million Btu.  
[391-3-1-.02(2)(sss)16.]

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**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 3B for the determination of the emissions rate correction factor or excess air. Method 3A may be used as an alternate,
  - e. Method 4 for the determination of stack gas moisture,
  - f. Method 5 or Method 17 for the determination of Particulate Matter concentration,
  - g. Method 6 or 6C for the determination of Sulfur Dioxide concentration,
  - h. Method 7 or 7E for the determination of Nitrogen Oxides concentration,
  - i. Method 9 and the procedures contained in Section 1.3 of the above reference document for the determination of opacity,
  - j. Method 10 for the determination of carbon monoxide concentration,
  - k. Method 19, section 12.5.2.2.3 or the procedures specified in 40 CFR Part 75, Appendix D for the determination of the sulfur content of fuel oil,

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- 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. ASTM Method D4629 or D3228 for the determination of fuel oil nitrogen content,
- n. Method 20 for the concentration of nitrogen oxides from the combustion turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08),
- o. Method 25A for the determination of volatile organic compounds, as carbon.

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)]

### **State Only Enforceable Condition**

- 4.1.4 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 unit(s) at the frequency specified:

- a. For particulate matter on the steam generating unit (Emission Unit ID SG01). The test shall be conducted annually at approximately twelve month intervals not to exceed thirteen months between tests. The Permittee may, if test results from the previous annual tests are fifty percent or less of the limitation in Condition 3.4.1, request that testing be deferred for a period no greater than twelve months from the required annual test date. Such request shall be in written form at least thirty days prior to the scheduled test.

[391-3-1-.02(6)(b)1(i)]

- b. For nitrogen oxide emissions while combusting natural gas and while combusting fuel oil in each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08). Testing shall be conducted at a minimum of four points in the operating range of the turbines for each fuel, including the minimum point in the range and the peak load. The tests shall be conducted at the frequency specified for retesting on the nitrogen oxides emission rate under 40 CFR 75, Appendix E, §2.2 (at least once every 20 calendar quarters following the issuance of the Part 72 permit for each affected unit). The results of the tests shall be used to establish or (verify) a water/fuel flow ratio under Condition 6.1.7a.ii. that has been determined to demonstrate with the limits in Conditions 3.3.1a. and 3.3.2a.



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- c. For carbon monoxide while combusting natural gas and while combusting fuel oil in each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08). Testing shall be conducted at a minimum of three points in the operating range of the turbines for each fuel, including the minimum point in the range and the peak load. Testing shall be conducted at the same frequency as testing for nitrogen oxide emissions under Condition 4.2.1b. The results of the tests shall be used to verify that the specified operating load (Megawatts) in Condition 6.1.7a.ii. is appropriate for assuring compliance with the limits in Conditions 3.3.1b. and 3.3.2b.

**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 or parameters 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), for the measurement of opacity, on the steam generating unit (Emission Unit ID SG01).
  - b. A device to measure and record the quantity of fuel oil, in gallons, and the quantity of natural gas, in cubic feet, burned in each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08).  
[40 CFR 52.21]
  - c. A monitoring system to monitor and record the ratio of water to fuel being burned in each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08).  
[40 CFR 60.334(a)]
  - d. A system to continuously monitor and record the coal feed rate (tons/hour) to the coal pulverizing mills for the steam generating unit (Emission Unit ID SG01). 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)]
- 5.2.2 The Permittee shall determine the electrical output (MW) for each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) for each hour of operation. For the purposes of this permit, each hour of combustion turbine operation shall begin on the clock hour.  
[40 CFR 70.6(a)(3)(i)]

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- 5.2.3 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
CT01	Nitrogen Oxides
CT02	Nitrogen Oxides
CT03	Nitrogen Oxides
CT04	Nitrogen Oxides
CT05	Nitrogen Oxides
CT06	Nitrogen Oxides
CT07	Nitrogen Oxides
CT08	Nitrogen Oxides
SG01	Particulate Matter

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]

- 5.2.4 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides emissions from Combustion Turbine Unit #1. [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 water/fuel flow ratio is continuously measured and displayed on the unit control system. The monitor was installed and certified according to performance specification. Fuel Flow is monitored with flow meters certified under 40 CFR Part 75, Appendix D. Water flow is also 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)]	NA
C. QA/QC Practices and Criteria [64.3(b)(3)]	Fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	Fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all hourly average water/fuel ratio data.
Averaging Period [64.3(b)(4)]	The one-minute data is used to calculate the one-hour average.

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5.2.5 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides emissions from Combustion Turbine Unit #2.  
[40 CFR 64.6(c)(1)(iii)]

<b>Performance Criteria [64.4(a)(3)]</b>	<b>Indicator No. 1 Water/fuel flow ratio</b>
A. Data Representativeness [64.3(b)(1)]	The water/fuel flow ratio is continuously measured and displayed on the unit control system. The monitor was installed and certified according to performance specification. Fuel Flow is monitored with flow meters certified under 40 CFR Part 75, Appendix D. Water flow is also 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)]	NA
C. QA/QC Practices and Criteria [64.3(b)(3)]	Fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	Fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all hourly average water/fuel ratio data.
Averaging Period [64.3(b)(4)]	The one-minute data is used to calculate the one-hour average.

5.2.6 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides emissions from Combustion Turbine Unit #3.  
[40 CFR 64.6(c)(1)(iii)]

<b>Performance Criteria [64.4(a)(3)]</b>	<b>Indicator No. 1 Water/fuel flow ratio</b>
A. Data Representativeness [64.3(b)(1)]	The water/fuel flow ratio is continuously measured and displayed on the unit control system. The monitor was installed and certified according to performance specification. Fuel Flow is monitored with flow meters certified under 40 CFR Part 75, Appendix D. Water flow is also 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)]	NA

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Performance Criteria [64.4(a)(3)]	Indicator No. 1 Water/fuel flow ratio
C. QA/QC Practices and Criteria [64.3(b)(3)]	Fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	Fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all hourly average water/fuel ratio data.
Averaging Period [64.3(b)(4)]	The one-minute data is used to calculate the one-hour average.

5.2.7 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides emissions from Combustion Turbine Unit #4.  
[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 water/fuel flow ratio is continuously measured and displayed on the unit control system. The monitor was installed and certified according to performance specification. Fuel Flow is monitored with flow meters certified under 40 CFR Part 75, Appendix D. Water flow is also 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)]	NA
C. QA/QC Practices and Criteria [64.3(b)(3)]	Fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	Fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all hourly average water/fuel ratio data.
Averaging Period [64.3(b)(4)]	The one-minute data is used to calculate the one-hour average.

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5.2.8 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides emissions from Combustion Turbine Unit #5.  
[40 CFR 64.6(c)(1)(iii)]

<b>Performance Criteria [64.4(a)(3)]</b>	<b>Indicator No. 1 Water/fuel flow ratio</b>
A. Data Representativeness [64.3(b)(1)]	The water/fuel flow ratio is continuously measured and displayed on the unit control system. The monitor was installed and certified according to performance specification. Fuel Flow is monitored with flow meters certified under 40 CFR Part 75, Appendix D. Water flow is also 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)]	NA
C. QA/QC Practices and Criteria [64.3(b)(3)]	Fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	Fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all hourly average water/fuel ratio data.
Averaging Period [64.3(b)(4)]	The one-minute data is used to calculate the one-hour average.

5.2.9 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides emissions from Combustion Turbine Unit #6.  
[40 CFR 64.6(c)(1)(iii)]

<b>Performance Criteria [64.4(a)(3)]</b>	<b>Indicator No. 1 Water/fuel flow ratio</b>
A. Data Representativeness [64.3(b)(1)]	The water/fuel flow ratio is continuously measured and displayed on the unit control system. The monitor was installed and certified according to performance specification. Fuel Flow is monitored with flow meters certified under 40 CFR Part 75, Appendix D. Water flow is also 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)]	NA

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Performance Criteria [64.4(a)(3)]	Indicator No. 1 Water/fuel flow ratio
C. QA/QC Practices and Criteria [64.3(b)(3)]	Fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	Fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all hourly average water/fuel ratio data.
Averaging Period [64.3(b)(4)]	The one-minute data is used to calculate the one-hour average.

- 5.2.10 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides emissions from Combustion Turbine Unit #7.  
[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 water/fuel flow ratio is continuously measured and displayed on the unit control system. The monitor was installed and certified according to performance specification. Fuel Flow is monitored with flow meters certified under 40 CFR Part 75, Appendix D. Water flow is also 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)]	NA
C. QA/QC Practices and Criteria [64.3(b)(3)]	Fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	Fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all hourly average water/fuel ratio data.
Averaging Period [64.3(b)(4)]	The one-minute data is used to calculate the one-hour average.

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5.2.11 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides emissions from Combustion Turbine Unit #8.  
[40 CFR 64.6(c)(1)(iii)]

<b>Performance Criteria [64.4(a)(3)]</b>	<b>Indicator No. 1 Water/fuel flow ratio</b>
A. Data Representativeness [64.3(b)(1)]	The water/fuel flow ratio is continuously measured and displayed on the unit control system. The monitor was installed and certified according to performance specification. Fuel Flow is monitored with flow meters certified under 40 CFR Part 75, Appendix D. Water flow is also 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)]	NA
C. QA/QC Practices and Criteria [64.3(b)(3)]	Fuel and water flow meters are calibrated per manufacturer's recommendations.
D. Monitoring Frequency [64.3(b)(4)]	Fuel and water flow are monitored continuously. The water/fuel ratio is calculated continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all hourly average water/fuel ratio data.
Averaging Period [64.3(b)(4)]	The one-minute data is used to calculate the one-hour average.

5.2.12 The Permittee shall comply with the performance criteria listed in the table below for the particulate matter emissions from Steam Generating Unit #1.  
[40 CFR 64.6(c)(1)(iii)]

<b>Performance Criteria [64.4(a)(3)]</b>	<b>Indicator No. 1 Opacity from EP01 Exhaust</b>
A. Data Representativeness [64.3(b)(1)]	The continuous emissions monitoring system (COMS) is located in EP01 exhaust. The COMS was installed at a representative location per 40 CFR 60, Appendix B, PS-1. The monitor was installed and certified according to performance specification.
B. Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	NA



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Performance Criteria [64.4(a)(3)]	Indicator No. 1 Opacity from EP01 Exhaust
C. 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.
D. Monitoring Frequency [64.3(b)(4)]	The opacity is monitored continuously.
Data Collection Procedures [64.3(b)(4)]	The DAS retains all six-minute opacity data.
Averaging Period [64.3(b)(4)]	The six-minute data is used to calculate the three-hour block average.

- 5.2.13 The Permittee shall, at all times, maintain the monitoring required by Conditions 5.2.4, 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, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.  
[40 CFR 64.7(b)]
- 5.2.14 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)]

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- 5.2.15 Upon detecting an excursion or exceedance as defined in Condition 6.1.7, 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)]
- 5.2.16 If the Permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring in Conditions 5.2.4, 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 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)]
- 5.2.17 The Permittee shall determine the three-hour block average sulfur content (%S) of coal burned in steam generating unit SG01 for each day or portion of a day that coal is burned in said unit. 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. 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(i) and 40 CFR 70.6(a)(3)(i)]

$$\%S = \left[ \frac{E_{SO_2} * 0.5}{(Coalflow) * (0.97) * (1-K)} \right] * 100\%$$

where S equals the coal sulfur content in percent by weight;  $E_{SO_2}$  equals the  $SO_2$  emissions, as determined by the Part 75 continuous emissions monitoring system in lbs per hour; 0.5 equals the ratio of sulfur and sulfur dioxide molecular weights, dimensionless; Coalflow equals the coal flow rate as determined from the coal flow meters in pounds per hour; K equals a correction factor for moisture fraction, default value of 0.060 to be used; 0.97 equals a constant which accounts for ash retention, dimensionless.

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- 5.2.18 The Permittee shall, upon written request by the Division, analyze any used oil to be burned in Steam Generating Unit 1. 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 concentration of arsenic, cadmium, chromium, and lead.
  - c. SW-846 Method 9077C 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*).
- 5.2.19 The Permittee shall monitor the sulfur content and nitrogen content of the fuels being burned in the combustion turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) as follows:  
[40 CFR 70.6(a)(3)(i)]
- a. For natural gas, the Permittee shall monitor the sulfur content by the submittal of semiannual analysis of the gas by the supplier. No determination of the nitrogen content shall be required.  
[391-3-1-.02(6)(b)1(i); 40 CFR 70.6(a)(3)(i); Delegation of Authority to Regions for Custom Fuel Monitoring Schedules under NSPS GG approved by U.S. EPA; August 14, 1987; 40 CFR 60.334(h)(1), (h)(2), and (h)(4)]
  - b. For fuel oil, the Permittee shall determine the sulfur content and the nitrogen content each day of operation of the combustion turbines.  
[40 CFR 60.334(h)(4)]

**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 of monitors required by 5.2 of this permit 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.

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- c. The magnitude of all excess emissions, exceedances and excursions computed in accordance with Condition 6.1.7 of this permit, 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)]

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- 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)(iii)]
- 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. Any period during which the sulfur content of the fuel oil burned in the combustion turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) exceeds 0.5 percent sulfur by weight, as indicated by the sulfur analysis required by Condition 5.2.19b.  
[40 CFR 60.334(j)(2)]
    - ii. Any unit operating hour during which the monitoring system required in Condition 5.2.1c, falls below the water-to-fuel ratio determined to demonstrate compliance with the limits in Conditions 3.3.1a and 3.3.2a. The water-to-fuel ratio determined to demonstrate compliance at the load (Megawatts) at which the turbine is being operated shall be based upon the correlation established during the most recent performance test approved by the Division. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.  
[40 CFR 60.334(j)(1)]
  - 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. For Unit 1 (Emission Unit ID SG01), any twenty-four hour block average during which the arithmetic average coal sulfur content, as determined in accordance with Condition 6.2.4, exceeds 3.0 percent. A twenty-four hour block average shall be defined as a twenty-four hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire twenty-four hour period.
    - ii. For each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08), any annual average fuel oil sulfur content, as determined in accordance with Condition 3.3.6, which exceeds 0.05 percent by weight. For purposes of this condition, an annual period is represented by a calendar year.  
[40 CFR 52.21]
    - iii. Any time fuel is fired in the startup boiler (Emission Unit ID SB01) that has a sulfur content which exceeds 2.5 percent sulfur, by weight.

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- iv. Any six-minute period during which the average opacity, as measured by the COMS for the steam generating unit (Emission Unit ID SG01) exceeds 40 percent.
- 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 Unit 1 (Emission Unit ID SG01), any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 28 percent (for combustion of fuel which does not include Pine Branch coal) or 22.5 percent (for combustion of fuel which includes Pine Branch coal). 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.
  - ii. Any period of time greater than 3 hours in which any combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) is operated below 50 MW.
  - iii. Any period during which the fuel-bound nitrogen of the fuel oil burned in the combustion turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) is greater than 0.06 percent by weight.  
[40 CFR 60.334(c)(1)]
- d. In addition to the excess emissions, exceedances and excursions specified above, the following should also be included with the report required in Condition 6.1.4:
  - i. The Permittee shall submit written reports to the Division of the analyses of the fuel oil and used oil burned in Steam Generating Unit 1 (Emission Unit ID SG01). Reports shall be submitted for each quarter ending on March 31, June 30, September 30, and December 31, and records shall be submitted along with the quarterly reports required in Condition 6.1.4.  
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]
  - ii. The Permittee shall submit written reports to the Division which specify the twenty-four hour block arithmetic average coal sulfur content for the steam generating unit (Emission Unit ID SG01) for each day in the reporting period. Reports shall be submitted for each quarter ending on March 31, June 30, September 30, and December 31, and records shall be submitted along with the quarterly reports required in Condition 6.1.4.  
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]

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- iii. The Permittee shall submit to the Division a written report showing the quantities of fuel oil and natural gas consumed by each turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) and the combined heat input from the consumption of such fuels in each turbine for every calendar quarter. Reports shall be submitted for each quarter ending on March 31, June 30, September 30, and December 31, and records shall be submitted along with the quarterly reports required in Condition 6.1.4.  
[40 CFR 52.21]

### 6.2 Specific Record Keeping and Reporting Requirements

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- 6.2.1 The Permittee shall retain monthly records of all fuel burned (except c. and d. below which shall be monitored on an as received basis) in the steam generating unit (Emission Unit ID SG01). 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.
- 6.2.2 The Permittee shall maintain a record of all actions taken in accordance with Condition 3.4.4 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)]
- 6.2.3 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(i)]



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- 6.2.4 The Permittee shall use the monitoring required by Condition 5.2.17 for the steam generating unit (Emission Unit ID SG01) to determine and record the twenty-four hour block arithmetic average coal sulfur content, on a daily basis. The record shall so note when coal has not been combusted in the steam generating unit (emission unit ID SG01) during any twenty-four hour block period.

These records shall include all calculations used to determine this parameter as well as be maintained in a format suitable and available for submittal or inspection by the Division. A twenty-four hour block average shall be defined as a twenty-four hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit (Emission Unit ID SG01). It is not necessary for fuel to be combusted continuously for the entire twenty-four hour period.

[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]

### **State Only Enforceable Condition**

- 6.2.5 The Permittee shall maintain records of representative samples of the coal and sawdust burned in the steam generating unit (Emission Unit ID SG01). 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.

- 6.2.6 The Permittee shall maintain records of the fuel oil and natural gas consumed by each of the turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) and shall determine the heat input for each turbine on a quarterly basis. The records shall be in a permanent form suitable and available for inspection. For the purposes of this condition, the heat input rate for fuel oil shall be calculated by multiplying the fuel oil consumed (in gallons) in each quarter by 137,000 Btu per gallon. The heat input rate for natural gas shall be calculated by multiplying the natural gas consumed (in cubic feet) in each quarter by 1022 Btu per cubic foot. The amount of fuel oil or natural gas consumed shall be determined using the measurement devices required in Condition 5.2.1b.

[40 CFR 70.6(a)(3)(i), 40 CFR 52.21]

- 6.2.7 For each shipment of fuel oil received for combustion in the steam generating unit with Emission Unit ID SG01, the Permittee shall obtain from the supplier of the fuel oil, a statement certifying that the oil complies with the specifications of fuel oil contained 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 and 40 CFR 70.6(a)(3)(i)]

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- 6.2.8 The Permittee shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined by 40 CFR 60.334(j).  
[391-3-1-.02(6)(b)1, 40 CFR 60.7(c), 40 CFR 60.334(j), 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.

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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:

- a. Sand Blasting for maintenance purposes in accordance with Georgia Rule 391-3-1-.02(b)(n).
- b. Asbestos removal in accordance with Georgia Rule 391-3-1-.02(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.

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### 7.9 Acid Rain Requirements

Facility ORIS code: 6124

Effective: January 01, 2012 through December 31, 2016

- 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<sub>2</sub> Allowance Allocations and NO<sub>x</sub> Requirements for each affected unit  
[40 CFR 73 (SO<sub>2</sub>) and 40 CFR 76 (NO<sub>x</sub>)]

Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
CT01	CT1	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	0	0	0	0	0
		NO <sub>x</sub> Limit	This affected unit is not subject to the NO <sub>x</sub> requirements of 40 CFR Part 76.				

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Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
CT02	CT2	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	0	0	0	0	0
		NO <sub>x</sub> Limit	This affected unit is not subject to the NO <sub>x</sub> requirements of 40 CFR Part 76.				

Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
CT03	CT3	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	0	0	0	0	0
		NO <sub>x</sub> Limit	This affected unit is not subject to the NO <sub>x</sub> requirements of 40 CFR Part 76.				

Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
CT04	CT4	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	0	0	0	0	0
		NO <sub>x</sub> Limit	This affected unit is not subject to the NO <sub>x</sub> requirements of 40 CFR Part 76.				

Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
CT05	CT5	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	0	0	0	0	0
		NO <sub>x</sub> Limit	This affected unit is not subject to the NO <sub>x</sub> requirements of 40 CFR Part 76.				

Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
CT06	CT6	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	0	0	0	0	0
		NO <sub>x</sub> Limit	This affected unit is not subject to the NO <sub>x</sub> requirements of 40 CFR Part 76.				

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Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
CT07	CT7	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	0	0	0	0	0
		NO <sub>x</sub> Limit	This affected unit is not subject to the NO <sub>x</sub> requirements of 40 CFR Part 76.				

Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
CT08	CT8	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	0	0	0	0	0
		NO <sub>x</sub> Limit	This affected unit is not subject to the NO <sub>x</sub> requirements of 40 CFR Part 76.				

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Emission Unit ID	EPA ID		2012	2013	2014	2015	2016
SG01	1	SO <sub>2</sub> allowances under Tables 2,3, or 4 of 40 CFR Part 73.	5565	5565	5565	5565	5565
		NO <sub>x</sub> Limit	The standard annual average NO <sub>x</sub> limit for a Phase I wall-fired boiler is 0.50 lb/mmBtu. In lieu of this limit, the Permittee may comply with 40 CFR Part 76 by complying with an approved Phase II NO <sub>x</sub> averaging plan as described below.				
<p>Pursuant to 40 CFR 76.11, Georgia EPD approves five NO<sub>x</sub> emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2012, 2013, 2014, 2015, and 2016. Under each plan, this unit's NO<sub>x</sub> emissions shall not exceed the annual average alternative contemporaneous emission limitation of <b>0.86 lb/mmBtu</b>. In addition, this unit shall not have an annual heat input greater than <b>9,215,784 mmBtu</b>.</p> <p>Under the plan, the actual Btu-weighted annual average NO<sub>x</sub> emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO<sub>x</sub> 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.</p> <p>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.</p> <p>In addition to the described NO<sub>x</sub> compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO<sub>x</sub> compliance plan and requirements covering excess emissions.</p>							

7.9.8 Permit Application: The Phase II Acid Rain Permit Application and Compliance 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

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- 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](http://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.

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- 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:

<b>Air Quality Permit and Amendment Number(s)</b>	<b>Dates of Original Permit or Amendment Issuance</b>
4911-103-0003-V-02-0	January 10, 2007
4911-103-0003-V-02-1	March 12, 2009
4911-103-0003-V-02-2	June 8, 2009
4911-103-0003-V-02-3	September 18, 2009
4911-103-0003-V-02-4	March 2, 2012

### 7.13 Pollution Prevention

None applicable.

### 7.14 Specific Conditions

None applicable.

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**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<sub>x</sub> 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	1	CAIR Facility Wide Annual NO <sub>x</sub> Allowances (tpy)	738	738
	CT01	CT1			
	CT02	CT2			
	CT03	CT3			
	CT04	CT4			
	CT05	CT5			
	CT06	CT6			
	CT07	CT7			
	CT08	CT8			

**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)]

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- 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)]



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- 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)]

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- 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;

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- 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.



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- 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 Internal Combustion Engines**

- 8.27.1 The Permittee shall comply with all applicable provisions of New Source Performance Standards (NSPS) as found in 40 CFR 60 Subpart A - "General Provisions" and 40 CFR 60 Subpart IIII-“Standard of Performance 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 60.4200, 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.
- 8.27.2 The Permittee shall comply with all applicable provisions of New Source Performance Standards (NSPS) as found in 40 CFR 60 Subpart A - "General Provisions" and 40 CFR 60 Subpart JJJJ-“Standard of Performance for Stationary Spark Ignition Internal Combustion Engines,” for spark ignition internal combustion engines(s) (gasoline, natural gas, liquefied petroleum gas or propane-fired) manufactured after July 1, 2007 or modified/reconstructed after June 12, 2006.  
[40 CFR 60.4230, 391-3-1-.02(8)(b)79]
- 8.27.3 The Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart ZZZZ-“National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.”  
[40 CFR 63.6580, 391-3-1-.02(9)(b)118]

**8.28 Boilers and Process Heaters**

- 8.28.1 The Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63 Subpart A-"General Provisions" and 40 CFR 63 Subpart JJJJJ-“ National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers.”  
[40 CFR 63.11193]
- 8.28.2 The Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63 Subpart A-"General Provisions" and 40 CFR 63 Subpart DDDDD-“ National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.”  
[40 CFR 63.7480]

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McIntosh Steam – Electric Generating Plant

Permit No.: 4911-103-0003-V-03-0

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### 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<sub>2</sub> and NO<sub>x</sub> Annual Trading Programs

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**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 <sub>2</sub> O (H <sub>2</sub> O)	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 <sub>x</sub> (NO <sub>x</sub> )	Nitrogen Oxides
NSPS	New Source Performance Standards
OCGA	Official Code of Georgia Annotated

PM	Particulate Matter
PM <sub>10</sub> (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 <sub>2</sub> (SO <sub>2</sub> )	Sulfur Dioxide
USC	United States Code
VE	Visible Emissions
VOC	Volatile Organic Compound

**List of Permit Specific Abbreviations**

ESP	Electrostatic Precipitator
PCBs	Polychlorinated Biphenyls


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### 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
<b>Mobile Sources</b>	1. Cleaning and sweeping of streets and paved surfaces	X
<b>Combustion Equipment</b>	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  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.  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.	2
<b>Trade Operations</b>	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
<b>Maintenance, Cleaning, and Housekeeping</b>	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.	1
	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.	

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### INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
<b>Laboratories and Testing</b>	1. Laboratory fume hoods and vents associated with bench-scale laboratory equipment used for physical or chemical analysis.	1
	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.	
<b>Pollution Control</b>	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.	
	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
<b>Industrial Operations</b>	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: <ul style="list-style-type: none"> <li>i) Furnaces for heat treating glass or metals, the use of which do not involve molten materials or oil-coated parts.</li> <li>ii) Porcelain enameling furnaces or porcelain enameling drying ovens.</li> <li>iii) Kilns for firing ceramic ware.</li> <li>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.</li> <li>v) Bakery ovens and confection cookers.</li> <li>vi) Feed mill ovens.</li> <li>vii) Surface coating drying ovens</li> </ul>	
	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: <ul style="list-style-type: none"> <li>i) Activity is performed indoors; &amp;</li> <li>ii) No significant fugitive particulate emissions enter the environment; &amp;</li> <li>iii) No visible emissions enter the outdoor atmosphere.</li> </ul>	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.	

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### INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
<b>Storage Tanks and Equipment</b>	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.	1
	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.	1
	3. All petroleum liquid storage tanks with a capacity of less than 10,000 gallons storing a petroleum liquid.	12
	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.	
	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.	<99
	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).	4

### INSIGNIFICANT ACTIVITIES BASED ON EMISSION LEVELS

Description of Emission Units / Activities	Quantity
Not Applicable	

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**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)
Not Applicable				

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](http://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](http://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).

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**ATTACHMENT D**

**U.S. EPA Acid Rain Program Phase II Permit Application**



United States  
Environmental Protection Agency  
Acid Rain Program

RECEIVED

JUN 29 2011

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

AIR PROTECTION BRANCH

# Acid Rain Permit Application

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

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

### STEP 1

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

Facility (Source) Name: McIntosh	State: GA	Plant Code: 6124
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### 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
CT1	Yes
CT2	Yes
CT3	Yes
CT4	Yes
CT5	Yes
CT6	Yes
CT7	Yes
CT8	Yes

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

### 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).

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

### **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

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

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): McIntosh

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	<i>Ronald Shipman</i>	Date 6/27/2011

**Title V Permit**

McIntosh Steam – Electric Generating Plant

Permit No.: 4911-103-0003-V-03-0

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**ATTACHMENT E**

**CAIR PERMIT APPLICATION FOR SO<sub>2</sub> and NO<sub>x</sub>  
ANNUAL TRADING PROGRAMS**



10300003

# 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

This submission is:  New  Revised

RECEIVED

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

McIntosh Plant Name	GA State	6124 ORIS/Facility Code	DEC 18 2008
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18669

AIR PROTECTION BRANCH  
NO<sub>x</sub> Ozone Season

**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 <sub>x</sub> Annual	SO <sub>2</sub>	NO <sub>x</sub> Ozone Season
1	X	X	
CT1	X	X	
CT2	X	X	
CT3	X	X	
CT4	X	X	
CT5	X	X	
CT6	X	X	
CT7	X	X	
CT8	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<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> 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<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> 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<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) that is not otherwise required to have a title V operating permit and each CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> 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<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) and such CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> Ozone Season unit (as applicable).

STEP 3,  
continued

(b) Monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) and each CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> 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<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) with the CAIR NO<sub>x</sub> emissions limitation, CAIR SO<sub>2</sub> emissions limitation, and CAIR NO<sub>x</sub> 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<sub>x</sub> source and each CAIR NO<sub>x</sub> unit at the source shall hold, in the source's compliance account, CAIR NO<sub>x</sub> 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<sub>x</sub> units at the source, as determined in accordance with subpart HH of 40 CFR part 96.

(2) A CAIR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> allowance was allocated.

(4) CAIR NO<sub>x</sub> allowances shall be held in, deducted from, or transferred into or among CAIR NO<sub>x</sub> Allowance Tracking System accounts in accordance with subparts FF, GG, and II of 40 CFR part 96.

(5) A CAIR NO<sub>x</sub> allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO<sub>x</sub> Annual Trading Program. No provision of the CAIR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> allowance to or from a CAIR NO<sub>x</sub> source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO<sub>x</sub> unit.

Sulfur dioxide emission requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO<sub>2</sub> source and each CAIR SO<sub>2</sub> unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO<sub>2</sub> 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<sub>2</sub> units at the source, as determined in accordance with subpart HHH of 40 CFR part 96.

(2) A CAIR SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> allowance was allocated.

(4) CAIR SO<sub>2</sub> allowances shall be held in, deducted from, or transferred into or among CAIR SO<sub>2</sub> Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of 40 CFR part 96.

(5) A CAIR SO<sub>2</sub> allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO<sub>2</sub> Trading Program. No provision of the CAIR SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> allowance to or from a CAIR SO<sub>2</sub> source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR SO<sub>2</sub> 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<sub>x</sub> Ozone Season source and each CAIR NO<sub>x</sub> Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO<sub>x</sub> 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<sub>x</sub> Ozone Season units at the source, as determined in accordance with subpart HHHH of 40 CFR part 96.

(2) A CAIR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season allowance was allocated.

(4) CAIR NO<sub>x</sub> Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO<sub>x</sub> Ozone Season Allowance Tracking System accounts in accordance with subparts FFFF, GGGG, and IIII of 40 CFR part 96.

(5) A CAIR NO<sub>x</sub> Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO<sub>x</sub> Ozone Season Trading Program. No provision of the CAIR NO<sub>x</sub> 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<sub>x</sub> Ozone Season 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<sub>x</sub> Ozone Season allowance to or from a CAIR NO<sub>x</sub> 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<sub>x</sub> source emits nitrogen oxides during any control period in excess of the CAIR NO<sub>x</sub> emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO<sub>x</sub> unit at the source shall surrender the CAIR NO<sub>x</sub> 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<sub>2</sub> source emits sulfur dioxide during any control period in excess of the CAIR SO<sub>2</sub> emissions limitation, then:

(1) The owners and operators of the source and each CAIR SO<sub>2</sub> unit at the source shall surrender the CAIR SO<sub>2</sub> 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<sub>x</sub> Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO<sub>x</sub> Ozone Season emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO<sub>x</sub> Ozone Season unit at the source shall surrender the CAIR NO<sub>x</sub> 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<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) and each CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> 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<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> 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<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, and CAIR NO<sub>x</sub> 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<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, and CAIR NO<sub>x</sub> Ozone Season Trading Program (as applicable) or to demonstrate compliance with the requirements of the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, and CAIR NO<sub>x</sub> Ozone Season Trading Program (as applicable).

(2) The CAIR designated representative of a CAIR NO<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) and each CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> Ozone Season unit (as applicable) at the source shall submit the reports required under the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, and CAIR NO<sub>x</sub> 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<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) and each NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> Ozone Season unit (as applicable) shall meet the requirements of the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, and CAIR NO<sub>x</sub> Ozone Season Trading Program (as applicable).

(2) Any provision of the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, and CAIR NO<sub>x</sub> Ozone Season Trading Program (as applicable) that applies to a CAIR NO<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) or the CAIR designated representative of a CAIR NO<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) shall also apply to the owners and operators of such source and of the CAIR NO<sub>x</sub> units, CAIR SO<sub>2</sub> units, and CAIR NO<sub>x</sub> Ozone Season units (as applicable) at the source.

(3) Any provision of the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, and CAIR NO<sub>x</sub> Ozone Season Trading Program (as applicable) that applies to a CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> Ozone Season unit (as applicable) or the CAIR designated representative of a CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> Ozone Season unit (as applicable) shall also apply to the owners and operators of such unit.

McIntosh  
Plant Name (from Step 1)

STEP 3,  
continued

(g) Effect on Other Authorities.

No provision of the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, and CAIR NO<sub>x</sub> 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<sub>x</sub> source, CAIR SO<sub>2</sub> source, and CAIR NO<sub>x</sub> Ozone Season source (as applicable) or CAIR NO<sub>x</sub> unit, CAIR SO<sub>2</sub> unit, and CAIR NO<sub>x</sub> 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 <i>Charles H. Huling</i>	12/12/2008 Date

RECEIVED

DEC 18 2008

AIR PROTECTION BRANCH

# EXHIBIT B



Giving Georgia's Environment Its Day In Court

July 5, 2012

**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 McIntosh Steam-Electric Generating Plant, Permit No. 4911-103-0003-V-03-0**

Dear Mr. Cornwell:

GreenLaw submits the following comments on the draft Major Source Operating Permit ("Draft Permit") for Southern Company/Georgia Power Company's ("GPC") McIntosh Steam-Electric Generating Plant on behalf of Sierra Club.<sup>1</sup> 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").

**I. Background**

The McIntosh Electric Generating Plant ("Plant McIntosh" or "Plant") is located in Rincon, Georgia. Plant McIntosh consists of one 178 megawatt coal-fired unit, eight simple-cycle combustion turbines burning natural gas, and two combined-cycle power blocks, each with two combustion turbines each with a supplementally fired heat recovery steam generator. The Draft Permit covers only the coal-fired unit and the eight simple-cycle combustion turbines.

Emissions from the coal-fired unit are controlled only by electrostatic precipitators ("ESPs"). Emissions from the gas-fired combustion units are controlled by water injection. The coal-fired unit exhausts to a 400-ft stack, while each the combustion turbine has its own 64-ft stack. Draft Permit at 1.

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<sup>1</sup> 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 McIntosh 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 vast majority of the regulated emissions from Plant McIntosh are a result of its one coal-fired unit.<sup>2</sup> In 2010, that unit was operated for approximately 2970 hours, and emitted 2504.9 tons of SO<sub>2</sub>, 902.5 tons of NO<sub>x</sub>, and 301134.3 tons of CO<sub>2</sub> into the environment. During the next year, 2011, the coal fired unit's operating time was reduced by over half to 1038 hours. However, it still emitted 691.6 tons of SO<sub>2</sub>, 257.5 tons of NO<sub>x</sub>, and 87,181.1 tons of CO<sub>2</sub> into the environment.

The previous Title V permit for the Plant expired on January 10, 2012. See 2007 Title V Permit at 1. EPD received GPC's application for renewal of the Title V permit for the Plant on June 29, 2011. Narrative at 1. EPD issued the Draft Permit and an accompanying Narrative for this facility for public notice.

## 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 requires 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 *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.

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).

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<sup>2</sup> Emissions data from search run on July 4, 2012 at <http://ampd.epa.gov/ampd/>.

### **III. 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).

### **IV. Emission Standards**

#### **a. Heat Inputs**

An increase in hourly heat input rate increases pollutant emissions from the Units at the Plant. 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<sub>x</sub> and SO<sub>2</sub>.

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. See Application TV-20540 at section labeled Boilers, Furnaces, Other Indirect Contact Heat Generating Equipment, SG01, available within database at <http://airpermit.dnr.state.ga.us/gatv/GATV/TitleV.asp> (last accessed July 4, 2012).

#### **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 unit "primarily burns coal," Draft Permit at 1, the Permittee is permitted to blend the coal with sawdust and biomass, or fire used oil. Draft Permit at 4-5. 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 used oil and biomass. However, while there is one meaningful limitation to the definition of "Biomass," municipal solid waste, this term still encompasses 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 Draft Permit's lb/MMBtu specifications.

The final permit should specifically limit the use of non-coal fuels, because the permit as drafted allows 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 V below.

**c. Particulate Matter**

**i. The PM Limit Should be Significantly Lowered**

Particulate matter ("PM"), also called particle pollution, is a complex mixture of 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 0.18 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(ii), 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 McIntosh 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. *See* 40 C.F.R. § 60.42 (Showing, as a comparison, that New Source Performance Standards for similar sources constructed after 1971 require a PM limit of 0.10 lb/MMBtu).

However, unlike other sources that were constructed prior to 1972 that have installed scrubbers to limit pollution, Plant McIntosh relies on EPS to control pollution from its coal-fired unit. As further discussed below, section IV.a.i, such control devices are often prone to ineffective operation. Decreasing the unreasonably lenient limit to a lower limit will ensure that the plant is properly incentivized to operate its ESP in an effective manner.

**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<sub>2.5</sub>, and coarse particle pollution, or PM<sub>10</sub>. 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<sub>10</sub> and PM<sub>2.5</sub> differ significantly, and separate NAAQS exist for each pollutant. Both PM<sub>10</sub> and PM<sub>2.5</sub> should be clearly regulated in the Draft Permit.

PM<sub>10</sub> and PM<sub>2.5</sub> 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<sub>10</sub> and PM<sub>2.5</sub> pose different kinds and levels of risk to human health. Because of its extremely small size, PM<sub>2.5</sub> can penetrate deep into the lungs, enter the blood stream, and cross the blood-brain barrier. As a result, PM<sub>2.5</sub> pollution causes more frequent and severe adverse health effects than PM<sub>10</sub>. 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<sub>2.5</sub> 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<sub>2.5</sub>),” 73 Fed. Reg. 28321, 28324 (May 16, 2008). Older adults, people with heart and lung disease, and children are particularly sensitive to PM<sub>2.5</sub> exposure. Id.

Finally, and most importantly, because of their different physical and behavioral characteristics, PM<sub>10</sub> and PM<sub>2.5</sub> are not effectively treated with the same pollution controls. In fact, EPA has recognized that PM<sub>10</sub> controls do not effectively control PM<sub>2.5</sub>: “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<sub>2.5</sub> have been resolved. 73 Fed. Reg. at 28340 (“With this final action [establishing NSR regulations for PM<sub>2.5</sub> and eliminating the PM<sub>10</sub> Surrogacy Policy] and technical developments in the interim, these difficulties have largely been resolved.”). Moreover, EPA announced in the final PM<sub>2.5</sub> 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<sub>10</sub> emissions information as a surrogate for PM<sub>2.5</sub> 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<sub>2.5</sub>.

**d. 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<sub>x</sub> allowance allocation for the Plant’s units through 2013. Draft Permit at 39, Condition 7.15. 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<sub>2</sub> and NO<sub>x</sub> to reduce transport of fine particulate matter and a separate ozone season NO<sub>x</sub> allowance trading program to reduce ground-level ozone. CAIR annual and seasonal NO<sub>x</sub> allowances will have no value for CSAPR compliance purposes, although the Acid Rain SO<sub>2</sub> program will continue as a separate program.

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

Unit	SO <sub>2</sub> Allocation 2012 (tons)	SO <sub>2</sub> Allocation 2014 (tons)	NOx Annual Allocation 2012 (tons)	NOx Annual Allocation 2014 (tons)	NOx OS Allocation 2012 (tons)	NOx OS Allocation 2014 (tons)
1	1,520	910	575	371	416	215
CT1	10	8	5	3	4	2
CT2	8	8	5	3	3	2
CT3	11	11	7	5	6	3
CT4	7	7	6	4	4	3
CT5	10	10	7	4	6	3
CT6	9	9	6	4	7	3
CT7	9	9	6	4	6	3
CT8	8	8	7	5	4	3

The above allocations give the facility both an SO<sub>2</sub> and an ozone season NO<sub>x</sub> allocation, whereas the CAIR provisions of the Draft Permit provide allocations only for annual NO<sub>x</sub>. See Draft Permit at 39, Condition 7.15.

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.

#### V. 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.a. 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.” Draft Permit at 47, Condition 8.14.4.b.

EPA has issued several guidance documents regarding excess emissions provisions.<sup>3</sup> 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<sub>2</sub> 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 McIntosh. Georgia SIP at 391-3-1-.02(2)(a)2, available at <http://www.epa.gov/region4/air/sips/ga/391-3-1.02.pdf> (last accessed July 4, 2012). For the reasons noted by EPA, Plant McIntosh 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.

**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. See, e.g., 1999 Herman Memo at 1. 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. See id. The state can excuse the source from penalties if the source can demonstrate that it meets certain

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<sup>3</sup> 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 (“1999 Herman Memo”); EPA Memo entitled “Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions,” by Kathleen M. Bennett dated February 15, 1983 (“1983 Bennett Memo”); EPA memo entitled “Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions,” by Kathleen M. Bennett, dated September 28, 1982 (“1982 Bennett Memo”).

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. 1999 Herman Memo at 2. 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” and “shutdown” are both defined within 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 exiting gas temperature above the sulfuric acid dew point.” Draft Permit at 5, Condition 3.2.2. Shutdown is defined as “cessation of the operation of a source or facility for any purpose.”

However, the term malfunction is not defined within the permit, and there does not seem to be a referenced definition that provides a limitation to this period. 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 term malfunction. The term is instead defined in the definitions section of the Georgia Air Quality Rules. See Rule 391-3-1-.01 at (nn). However, the definition of malfunction provided there is no more specific than the dictionary definitions of that term,<sup>4</sup> and thus does not provide any meaningful limits on this exempt period.

In order to ensure that the exemptions only apply when necessary, the final permit should specifically and 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 47, Condition 8.14.4(a). 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

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<sup>4</sup> “[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).

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 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). Specifically, the Draft Permit acknowledges that the coal-fired unit is subject to 40 C.F.R. 63, Subpart UUUUU, and thus Condition 8.14.4 should be revised to acknowledge that the affirmative defense is not applicable to emissions under this standard. See below Section IX.

**VI. 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 test. For the steam-generating unit, the tests will be conducted annually, at approximately 12 month intervals, not to exceed 13 months. Draft Permit at 4.2.1.a. However, under certain circumstances, the facility may be granted a deferral of 12 months. Draft Permit at 11, Condition 4.2.1.a. As a result, the Plant may only conduct stack testing for PM emissions three times over the term of the permit.

The expected operational variability of these units can significantly affect ESP 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 include more stringent monitoring requirements. The best option “to assure compliance with the permit terms and conditions” would require 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<sub>10</sub> 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>. However, at the very least, the Draft 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.

**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<sub>2.5</sub>, for which CEMS do not exist.

The Draft Permit mandates the use of continuous opacity monitoring systems (“COMS”) for the steam-generating unit. Draft Permit at 13, Condition 5.2.1. 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.

## **VII. 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, Condition 3.3.5. Rather, the Permittee is required to take “reasonable precautions.” Draft Permit at 9, Condition 3.4.4. 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.

## **VIII. 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. The Narrative states that Plan McIntosh is subject to the greenhouse gas monitoring and reporting requirements outlined in Subparts A, C, and D of 40 C.F.R. § 98. Narrative at 16–17. However, although the Narrative for Plant McIntosh acknowledges that the reporting requirements are applicable, the Draft Permit itself does not identify these requirements as applicable to Plant McIntosh.

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 revise the Draft Permit to 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.

#### **IX. 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 both the Narrative and the Draft Permit point out, Plant McIntosh is subject to 40 C.F.R. 63, Subpart UUUUU. Narrative at 5; Draft Permit at 8, Condition 3.3.9. 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.” 77 Fed. Reg. 9304. This rule went into effect on April 16, 2012, and it will be applicable to Plant McIntosh on April 16, 2015<sup>5</sup>, during the Title V permit term. Although the Draft Permit includes an acknowledgement that the Plant is subject to this new regulation, it does not contain any provisions reflecting the emissions standards or monitoring required under this rule. Thus, the Draft Permit should be revised to include the emissions standards and monitoring requirements from 40 C.F.R. 63, Subpart UUUUU that will be effective beginning April 16, 2015.

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 Bailey  
Staff Attorney  
GreenLaw

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<sup>5</sup> The narrative states that existing sources generally will have four years to comply with this rule. Narrative at 14. This is incorrect. The final rule states that existing sources must comply within three years, and may only be granted a one-year extension by the permitting authority on a case-by-case basis, “[i]f an existing source is unable, despite best efforts, to comply within 3 years.” 77 Fed. Reg. 9304, 9409.

# EXHIBIT C

Facility Name: **McIntosh Steam – Electric Generating Plant**  
 City: Rincon  
 County: Effingham  
 AIRS #: 04-13-103-00003

Application #: TV-20540  
 Date Application Received: June 29, 2011  
 Permit No: 4911-103-0003-V-03-0

Program	Review Engineers	Review Managers
<b>SSPP</b>	Tyneshia Tate	Furqan Shaikh
<b>ISMP</b>	Dave Sheffield	DeAnna Oser
<b>SSCP</b>	Pierre Sanson	James Eason
<b>Toxics</b>	Not Applicable	Michael Odom
<b>Permitting Program Manager</b>		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 **McIntosh 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: McIntosh Steam – Electric Generating Plant

2. Parent/Holding Company Name

Southern Company / Georgia Power

3. Previous and/or Other Name(s)

This facility is commonly known and referred to as Plant McIntosh. It was formerly known as Effingham Station (before 1983).

4. Facility Location

981 Old Augusta Rd.  
Rincon, Effingham County, Georgia

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

The facility is located in Effingham County which is designated as an attainment area for all criteria pollutants.

**B. Site Determination**

The McIntosh Steam-Electric Generating Plant (AFS No. 1030001) and the McIntosh Combined-Cycle Facility (AFS No. 10300014) comprise the same Title I and Title V site. The McIntosh Combined-Cycle Facility operates under a different Title V Permit.

**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
4911-103-0003-V-02-0	January 10, 2007	Title V Renewal
4911-103-0003-V-02-1	March 12, 2009	Significant modification without construction to update the Title IV Acid Rain Program Phase II NO <sub>x</sub> averaging plan for years 2009 to 2013 for Emission Unit SG01 in Condition 7.9.7 and Attachment D.
4911-103-0003-V-02-2	June 8, 2009	Minor modification without construction to include test methods ASTM D4629 and D3228 in Condition 4.1.3m. to determine No. 2 fuel oil nitrogen content.
4911-103-0003-V-02-3	September 18, 2009	Significant modification without construction to incorporate the requirements of 40 CFR 96 for Clean Air Interstate Rule (CAIR) for the SO <sub>2</sub> and NO <sub>x</sub> Annual Trading Programs
4911-103-0003-V-02-4	March 2, 2012	Minor modification without construction to revise the periodic reporting deadlines in Conditions 6.1.3, 6.1.4, 6.1.7, and 8.14.1.

#### D. Process Description

##### 1. SIC Codes(s)

Plant McIntosh operates under the SIC Code of 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 McIntosh generates electricity for sale.

3. Overall Facility Process Description

This facility includes one steam generating unit which primarily burns coal and eight simple cycle combustion turbines which primarily burn natural gas. Steam Generating Unit 1 powers its own steam turbine rated at 178 megawatts. The steam generating unit exhaust through a 400-ft stack.

The facility also has one startup boiler rated at  $21.73 \times 10^6$  Btu/hr heat input, which can be used during the startup of a steam generating unit when steam supply is not available from any other unit. As a result, the start-up boiler is rarely used.

4. Overall Process Flow Diagram

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

E. Regulatory Status

1. PSD/NSR

This facility is a major source under PSD because it has potential emissions of PM<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, VOC, and CO greater than 100 tpy (it is one of the 28 named source categories under PSD). Steam Generating Unit 1 was originally constructed before the PSD regulations were effective. The addition of the eight combustion turbines constituted a major modification to an existing major source and therefore was subject to PSD review at that time.

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	Y	✓		
PM <sub>10</sub>	Y	✓		
SO <sub>2</sub>	Y	✓		
VOC	Y	✓		
NO <sub>x</sub>	Y	✓		
CO	Y	✓		
TRS	Y			✓
H <sub>2</sub> S	Y			✓
Individual HAP	Y	✓		
Total HAPs	Y	✓		

## 3. MACT Standards

McIntosh Steam – Electric Generating Plant is a major source of hydrogen chloride (HCl) and Hydrogen Fluoride (HF) emissions which are hazardous air pollutants (HAPs).

The facility is subject to 40 CFR 63 Subpart YYYY - National Emission Standard for Hazardous Air Pollutants: Stationary Combustion Turbines. This regulation has no applicable requirements for existing turbines.

The facility's startup boiler is subject to 40 CFR 63 Subpart DDDDD – National Emission Standard for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.

The facility's coal-fired steam generating unit is 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. This rule became effective on April 16, 2012.

## 4. Program Applicability (AIRS Program Codes)

Program Code	Applicable (y/n)
Program Code 6 - PSD	Y
Program Code 8 – Part 61 NESHAP	N
Program Code 9 - NSPS	Y
Program Code M – Part 63 NESHAP	Y
Program Code V – Title V	Y

## Regulatory Analysis

### II. Facility Wide Requirements

A. Emission and Operating Caps:

None applicable.

B. Applicable Rules and Regulations

None applicable.

C. Compliance Status

Application Number 20540 does not indicate compliance issues with any applicable regulations.

D. Operational Flexibility

None applicable.

E. Permit Conditions

None applicable.

### III. Regulated Equipment Requirements

#### A. Brief Process Description

This facility includes one, primarily coal-fired, steam generating unit and eight, natural gas or #2 fuel oil-fired, simple cycle combustion turbines.

As part of Permit Number 4911-103-0003-V-03-0, Georgia Power is requesting to fire biodiesel or biodiesel blends for the same purposes as fuel oil as discussed later in this document.

#### B. Equipment List for the Process

##### 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	391-3-1-.02(2)(b) 391-3-1-.02(2)(d) 391-3-1-.02(2)(g) 40 CFR 63 Subpart A 40 CFR 63 Subpart UUUUU 40 CFR 64 Acid Rain	3.2.1, 3.2.2, 3.3.9, 3.4.1, 3.4.2, 3.4.3, 4.2.1, 5.2.1, 5.2.3, 5.2.12, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.18, 6.2.1, 6.2.2, 6.2.3, 6.2.4, 6.2.5, 6.2.7, 7.9.1 through 7.9.8	EP01	ESP
CT01	Combustion Turbine Unit #1	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(g) 40 CFR 60 Subpart A 40 CFR 60 Subpart GG 40 CFR 63 Subpart A 40 CFR 63 Subpart YYYY 40 CFR 64 Acid Rain	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.4, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	W11	Water Injection
CT02	Combustion Turbine Unit #2	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.5, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	W12	Water Injection
CT03	Combustion Turbine Unit #3	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.6, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	W13	Water Injection

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
CT04	Combustion Turbine Unit #4	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.7, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	W14	Water Injection
CT05	Combustion Turbine Unit #5	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.8, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.1, 6.2.3, 6.2.6, 7.9.1 through 7.9.8	W15	Water Injection
CT06	Combustion Turbine Unit #6	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.9, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.3, 6.2.6, 6.2.8, 7.9.1 through 7.9.8	W16	Water Injection
CT07	Combustion Turbine Unit #7	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.10, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.1, 6.2.3, 6.2.6, 7.9.1 through 7.9.8	W17	Water Injection
CT08	Combustion Turbine Unit #8	See CT01	3.2.3, 3.2.4, 3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.3.6, 3.3.7, 4.2.1, 5.2.1, 5.2.2, 5.2.3, 5.2.11, 5.2.13, 5.2.14, 5.2.15, 5.2.16, 5.2.17, 5.2.19, 6.2.1, 6.2.3, 6.2.6, 7.9.1 through 7.9.8	W18	Water Injection
CHS	Coal Handling System	391-3-1-.02(2)(n) 40 CFR 60 Subpart A 40 CFR 60 Subpart Y	3.3.5, 3.4.4, 6.2.2, 6.2.3	None	NA
AHS	Ash Handling System	391-3-1-.02(2)(n)	3.4.4, 3.4.5, 6.2.2, 6.2.3	None	NA
SB01	Start-Up Boiler Unit 1	391-3-1-.02(2)(b) 391-3-1-.02(2)(d) 391-3-1-.02(2)(g) 40 CFR 63 Subpart A 40 CFR 63 Subpart DDDDD	3.2.5, 3.3.8, 3.4.6, 3.4.7, 3.4.8, 5.2.18, 6.2.3	None	NA

### C. Equipment & Rule Applicability

#### Emission and Operating Caps:

Per the narrative associated with Permit Number 4911-103-0003-V-01-0, Steam Generating Unit 1 (SG01) is permitted to burn only certain fuels. Generally, this emission unit can burn only coal, with No. 2 fuel oil used for startup and flame stabilization. It may also burn small amounts of sawdust, biomass, or used oil which, if burned, would be blended with the coal during normal operation.

According to the narrative associated with Permit Number 4911-103-0003-V-01-0, the combustion turbines CT01 through CT08 are permitted to burn only natural gas or distillate fuel oil. The combustion turbines were each limited to  $2.2 \times 10^6$  MMBtu heat input per year in their PSD permit (about 2000 hours at full load). This value was used in the BACT analysis to determine potential emissions and therefore affected the costs of the potential control technology (\$/ton).

#### Rules and Regulations Assessment:

##### *Part 52.21, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 52.21) Prevention of Significant Deterioration (PSD)*

This regulation is applicable to the combustion turbines located at the McIntosh Steam – Electric Generating Plant for NO<sub>x</sub>, SO<sub>2</sub>, CO, PM, VOC, and opacity as discussed in Section I.E above. The Savannah Electric and Power Company received authorization to construct and operate the McIntosh Combined – Cycle Facility at the existing McIntosh Steam – Electric Generating Plant site. This authorization was provided by PSD/Title V Permit No. 4911-103-0014-V-01-0 on April 17, 2003. Thus, the site determination for Plant McIntosh was updated as mentioned in Section I.B. above.

According to the narrative associated with Permit Number 4911-103-0003-V-01-0, SG01 was originally designed to burn coal, but was constructed without all the equipment necessary to burn coal. On October 30, 1979, Savannah Electric (the owner of the unit at the time) submitted an application to add this necessary equipment including coal handling equipment, particulate matter control equipment, and ash handling equipment. According to the narrative associated with Permit Number 4911-103-0003-V-01-0, the boiler already had the coal burners and the fan capacity needed to burn coal. Since the boiler was deemed to be capable of accommodating coal prior to January 5, 1975, PSD did not apply to this operational change. An ESP was added to the boiler to ensure that the emission rate of particulate matter did not increase and an allowable emission rate of 0.18 pounds per million Btu was established to make it enforceable.

According to the narrative associated with Permit Number 4911-103-0003-V-01-0, the combustion turbines have allowable emission rates, in their PSD Permit, for PM, NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC, and opacity. The allowable emission rates, in the PSD Permit, are as follows:

Pollutant	Emission Limit While Firing Natural Gas	Emission Limit While Firing Fuel Oil
NO <sub>x</sub>	25 ppm	42 ppm (+ fuel oil N allowance)
SO <sub>2</sub>	-	0.5% sulfur content (daily)
CO	9 ppm (full load)	9 ppm (full load)
	350 ppm (<50% load)	350 ppm (<50% load)
PM	0.006 lb/MMBtu	0.012 lb/MMBtu
VOC	11 ppm (>75% load)	11 ppm (>75% load)
	30 ppm (<75% load)	30 ppm (<75% load)
Opacity	10 %	10 %

Permit Number 4911-103-0003-V-01-4 was issued to address the fuel oil sulfur content, of 0.3 weight percent, on an annual average basis. Per the permit amendment, Plant McIntosh reduced the BACT fuel oil sulfur limit from 0.3 weight percent to 0.05 weight percent on an annual average basis. There was a required contemporaneous reduction in SO<sub>2</sub> emissions in order for the operation of the two facilities on the property to comply with the Class I SO<sub>2</sub> increment and visibility impact analyses for Cape Romain and Wolf Island. For further discussion, see the narrative associated with Permit Number 4911-103-0003-V-01-4.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart A – General Provisions*

Except as provided in Subparts B and C of 40 CFR Part 60, the provisions of this regulation apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility [40 CFR 60.1(a)]. Plant McIntosh has several pieces of equipment and/or processes subject to this regulation. Any new or revised standard of performance promulgated pursuant to Section 111(b) of the Clean Air Act apply to McIntosh Steam – Electric Generating Plant's applicable equipment and/or processes and any applicable source/equipment for which the construction or modification of is commenced after the date of publication in 40 CFR 60 of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that equipment and/or processes [40 CFR 60.1(b)].

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standard (NSPS) Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971*

This regulation is applicable to each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat Input rate of more than 73 MW (250 MMBtu/hr) [40 CFR 60.40(a)(2)]. Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart. [40 CFR 60.40(b)].

According to the narrative associated with Permit Number 4911-103-0003-V-01-0, SG01 was under construction before August 17, 1971. Therefore, this regulation does not apply.



*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standard (NSPS) Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*

This regulation is applicable to an electric utility steam generating unit capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel (either alone or in combination with any other fuel); and construction, modification, or reconstruction commenced after September 18, 1978 [40 CFR 60.40da(a)]. Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart. [40 CFR 60.40da(d)].

According to the narrative associated with Permit Number 4911-103-0003-V-01-0, SG01 was under construction before September 18, 1978. Therefore, this regulation does not apply.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standard (NSPS) Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

This regulation is applicable to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) [40 CFR 60.40b(a)].

According to the narrative associated with Permit Number 4911-103-0003-V-01-0, SG01 was under construction before June 19, 1984. Therefore, this regulation does not apply.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standard (NSPS) Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.*

On October 15, 2003 in the Federal Register (68 FR 59328), the proposed revisions to 40 CFR 60 Subpart Kb became final. The NSPS in 40 CFR 60 Subpart Kb now completely exempt the following classes of tanks greater than 151 m<sup>3</sup> (39,894 gallons) in capacity with a content vapor pressure less than 3.5 kiloPascals (kPa) (0.51 pounds per square inch absolute [psia], 26.4 millimeters of mercury [mm Hg]). In addition, Georgia Rule 391-3-1-.3(6)(c)(1) exempts all petroleum liquid storage tanks storing a liquid with a true vapor pressure of equal to or less than 0.50 psia as stored. Storage Tank CTOT stores No. 2 fuel oil with a liquid total vapor pressure of 0.5 psia. The tank is now considered insignificant and has been removed from Table 3.1 and listed in Attachment B as an insignificant source in the storage tanks and equipment category per Permit Number 4911-103-0003-V-02-0.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart Y – Standards of Performance for Coal Preparation Plants*

This regulation is applicable to each affected facilities in coal preparation plants which process more than 181 Mg (200 tons) per day: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems [40 CFR 60.250(a)]. This regulation is applicable

to these type sources that commenced construction or modification after October 24, 1974 [40 CFR 60.250(b)]. The coal handling system located at McIntosh Steam – Electric Generating Plant was installed post-1974.

The whole transfer system is subject to opacity requirements. On and after the date on which the performance test required to be conducted by 40 CFR 60.11 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater [40 CFR 60.252(c)]. Testing associated with opacity limits required by this regulation is EPA Method 9, which the facility already uses to determine compliance with existing opacity limits. The facility shall be required to conduct monitoring, reporting, and record keeping as discussed in Sections IV, V and VI of this document.

*Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart GG – Standards of Performance for Stationary Gas Turbines*

This regulation is applicable to combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired, and constructed after October 3, 1977. The combustion turbines are subject to this regulation.

The allowable fuel sulfur content is 0.8 percent by weight in accordance with 40 CFR 60.333(b) for each turbine. The allowable NO<sub>x</sub> emission rate is specified by the following formula [40 CFR 60.332(a)(1)] because each turbine has a heat input rating greater than 100 million Btu/hr:

$$\text{STD} = 0.0075 (14.4/Y) + F$$

where: STD = allowable NO<sub>x</sub> emissions (% volume @ 15% O<sub>2</sub>, dry)

Y = heat rate in kilojoules per watt hour

F = fuel bound nitrogen allowance

These limitations may have been superseded by applicable PSD limits. Since the issuance of the original Title V Permit, this regulation has been modified. Applicable permit conditions have been modified to reflect rule changes.

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 63) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart A – General Provisions*

This regulation contains national emission standards for hazardous air pollutants (NESHAP) established pursuant to section 112 of the Act as amended November 15, 1990. These standards regulate specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants (HAPs) listed in this part pursuant to section 112(b) of the Act. The standards in this part are independent of NESHAP contained in 40 CFR 61. The NESHAP in part 61 promulgated by signature of the Administrator before November 15, 1990 (i.e., the date of enactment of the Clean Air Act Amendments of 1990) remain in effect until they are amended, if appropriate, and added to 40 CFR 63 [40 CFR 63.1(a)(1) and (2)]. No emission standard or other requirement established under 40 CFR 63 shall be interpreted, construed, or

applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 111, part C or D or any other authority of this Act), or a standard issued under State authority. The Administrator may specify in a specific standard under this part that facilities subject to other provisions under the Act need only comply with the provisions of that standard. [40 CFR 63.1(a)(3)]

The site, as defined above, has potential HAP emissions at or above the applicable major source thresholds of 10 tons for a single HAP and/or 25 tons per year for a combination of HAPs. Therefore, applicable regulations under 40 CFR 63 apply to the facility.

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 63) National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart YYYY- Standards for Stationary Combustion Turbines*

This regulation is applicable to combustion turbines that are located at a major source of hazardous air pollutants (HAPs) [40 CFR 63.6085]. The regulation defines an existing stationary turbine as a stationary combustion turbine which commenced construction or reconstruction on or before January 14, 2003 [40 CFR 63.6090(a)(1)]. Combustion Turbine Units CT01 through CT08 were constructed and began operation in 1994 and therefore is classified as existing combustion turbines.

Existing stationary combustion turbines in all subcategories do not have to meet the requirements of Subpart YYYY and of Subpart A of 40 CFR 63. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification [40 CFR 63.6090(4)]. Although the regulation is applicable, there are no emission limits, operating standards, notification requirements, or reporting requirements for Combustion Turbine Units CT01 through CT08.

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 63) National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart DDDDD- Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters*

This regulation is applicable to industrial, commercial, or institutional boilers or process heaters as defined in 40 CFR 63.7575 that are located at a major source of hazardous air pollutants (HAPs) [40 CFR 63.7485]. The regulation defines an existing boiler or process heater as a boiler or process heater which commenced construction or reconstruction on or before June 4, 2010 [40 CFR 63.7490(d)]. The startup boiler was constructed and began operation in 1979 and therefore is classified as an existing boiler. The startup boiler burns No. 2 fuel oil. As part of this renewal, Georgia Power has requested to fire biodiesel and biodiesel blends in the startup boiler as well.

On December 12, 2011, the EPA issued the reconsideration proposal of 40 CFR 63, Subpart DDDDD. The EPA will accept comment on the reconsideration proposal for 60 days following publication in the Federal Register. On January 9, 2012, a federal court vacated the EPA decision to delay the effective date of the regulation, saying the delay was unlawful. The court also remanded the delay notice to EPA. This means that new sources will have to comply immediately with the regulation; however, existing sources will have three years to comply with the regulation. This regulation is applicable to industrial, commercial, or institutional boilers or

process heaters as defined in the rule that are located at, or is part of, a major source of HAP. Per Permit Number 4911-103-0003-V-03-0, Permit Condition 3.3.8 was updated as a general applicability condition to address applicability of the proposed rule to the startup boiler.

*Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 63) National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart UUUUU- 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 May 3, 2011, the EPA proposed both national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs) and standards of performance for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units. On December 16, 2011, the EPA finalized the rule, and this rule became effective on April 16, 2012. Existing sources generally will have up to 4 years to comply with the rule. This regulation is applicable to the steam generating unit. Per Permit Number 4911-103-0003-V-03-0, Permit Condition 3.3.9 was updated as a general applicability condition to address applicability of the rule to the steam generating unit.

*Part 72, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 72) Permits Regulation [Acid Rain]*

The combustion turbines are subject to the requirements of the Acid Rain Program [40 CFR 72.6(a)(3)(i)]. Therefore, Plant McIntosh must meet applicable permit requirements, monitoring requirements, sulfur dioxide (SO<sub>2</sub>) requirements, nitrogen oxides (NO<sub>x</sub>) requirements, excess emissions requirements, and liability specifications as specified in 40 CFR 72.9. McIntosh Steam – Electric Generating Plant must follow all provisions specified in 40 CFR 72 Subparts A through I.

The regulation also sets forth requirements for obtaining three types of Acid Rain permits, during Phases I and II, for which an affected source may apply: Acid Rain permits issued by the United States Environmental Protection Agency during Phase I; the Acid Rain portion of an operating permit issued by a State permitting authority during Phase II; and the Acid Rain portion of an operating permit issued by EPA when it is the permitting authority during Phase II.

*Part 73, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 73) Sulfur Dioxide Allowance System*

The regulation requires owners, operators, and designated representatives of affected sources and affected units pursuant to 40 CFR 72.6 and as specified in 40 CFR 73. This regulation establishes the requirements and procedures for the following: (1) The allocation of sulfur dioxide emissions allowances; (2) The tracking, holding, and transfer of allowances; (3) The deduction of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to parts 72 and 77 of Chapter I; (4) The sale of allowances through EPA-sponsored auctions and a direct sale, including the independent power producers written guarantee program; and (5) The application for, and distribution of, allowances from the Conservation and Renewable Energy Reserve; and (6) The application for, and distribution of, allowances for desulfurization of fuel by small diesel refineries [40 CFR 73.1]. The combustion turbines and steam generating unit are subject to 40 CFR 73.

*Part 75, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 75) Continuous Emissions Monitoring*

The purpose of this regulation is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), and carbon dioxide (CO<sub>2</sub>) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 (November 15, 1990) [the Act]. In addition, this regulation sets forth provisions for the monitoring, recordkeeping, and reporting of NO<sub>x</sub> mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NO<sub>x</sub> mass emission reduction program, to the extent these provisions are adopted as requirements under such a program. McIntosh Steam – Electric Generating Plant must follow all provisions specified in 40 CFR 75 Subparts A through I. In accordance with 40 CFR 75.12(a), the owner or operator of gas-fired nonpeaking units or oil-fired nonpeaking units must meet the general operating requirements in 40 CFR 75.10 for a NO<sub>x</sub> continuous emission monitoring system (CEMS) for each affected unit.

*Part 76, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 76) Acid Rain Nitrogen Oxides Emission Reduction Program*

Except as provided in paragraphs (b) through (d) of 40 CFR 76.1, the provisions apply to each coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for SO<sub>2</sub> under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Clean Air Act [40 CFR 76.1(a)]. A coal-fired utility unit means a utility unit in which the combustion of coal (or any coal-derived fuel) on a Btu basis exceeds 50.0 percent of its annual heat input during the following calendar year: for Phase I units, in calendar year 1990; and, for Phase II units, in calendar year 1995 or, for a Phase II unit that did not combust any fuel that resulted in the generation of electricity in calendar year 1995, in any calendar year during the period 1990–1995. For the purposes 40 CFR 76, this definition shall apply notwithstanding the definition in 40 CFR 72.2 [40 CFR 76.2]. The steam generating unit is subject to this regulation. Based on this definition, the combustion turbines will not be subject to the emission limits in 40 CFR 76; however, they will be subject to the continuous monitoring of NO<sub>x</sub> emissions required under 40 CFR 75.

*Part 77, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 77) Excess Emissions*

This regulation sets forth the excess emissions offset planning and offset penalty requirements under section 411 of the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law 101–549 (November 15, 1990). These requirements shall apply to the owners and operators and, to the extent applicable, the designated representative of each affected unit and affected source under the Acid Rain Program. Nothing in 40 CFR 77 will limit or otherwise affect the application of sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Clean Air Act, as amended. Any allowance deduction, excess emission penalty, or interest required under 40 CFR 77 will not affect the liability of the affected unit's and affected source's owners and operators for any additional fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act. McIntosh Steam – Electric Generating Plant combustion turbines and steam generating unit must comply as applicable with this regulation.

*Part 96, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 96) Subpart AA – Clean Air Interstate Rule [CAIR] NO<sub>x</sub> Annual Trading Program General Provisions, Subpart BB – CAIR Designated Representative for CAIR NO<sub>x</sub> Sources, Subpart CC – Permits, Subpart EE – CAIR NO<sub>x</sub> Allowance Allocations, Subpart FF – CAIR NO<sub>x</sub> Allowance Tracking System, Subpart GG – CAIR NO<sub>x</sub> Allowance Transfers, Subpart HH – Monitoring and Reporting and Part 96, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 96) Subpart AAA – Clean Air Interstate Rule [CAIR] SO<sub>2</sub> Trading Program General Provisions, Subpart BBB – CAIR Designated Representative for CAIR SO<sub>2</sub> Sources, Subpart CCC – Permits, Subpart FFF – CAIR NO<sub>x</sub> Allowance Tracking System, Subpart GGG – CAIR NO<sub>x</sub> Allowance Transfers, Subpart HHH – Monitoring and Reporting*

Permit Amendment Number 4911-103-0003-V-02-3 incorporated the requirements of 40 CFR 96 for Clean Air Interstate Rule (CAIR) for the SO<sub>2</sub> and NO<sub>x</sub> Annual Trading Programs for steam generating unit and combustion turbines (denoted simply as Unit ID Nos. SG01 and CT01 through CT08 in CAIR Permit Application) in Section 7.15 and Attachment E. The facility was 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.

On July 6, 2011, the US EPA finalized a rule, known as the Cross-State Air Pollution Rule (CSAPR) which requires 27 states to improve air quality by reducing power plant emission that contribute to ozone and/or fine particle pollution in other states. This regulation was set to go into effect January 1, 2012. This rule was to replace CAIR.

However on December 30, 2011, the United States Court of Appeals for the D.C. Circuit issued it's ruling to stay the CSAPR pending judicial review. The Court further ordered that EPA continue administering CAIR pending final disposition of the case. As a result, EPA had to reinstate CAIR allowances, at least for 2012. Therefore, CAIR rule will continue to apply to this facility.

*Part 98, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 98) – Subpart A – General Provisions*

This regulation establishes mandatory greenhouse gas (GHG) reporting requirements for owners and operators of certain facilities that directly emit GHG as well as for certain fossil fuel suppliers and industrial GHG suppliers [40 CFR 98.1(a)]. Owners and operators of facilities and suppliers that are subject to 40 CFR 98 must follow the requirements of 40 CFR 98, Subpart A and all applicable subparts of 40 CFR 98. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the applicable subpart shall take precedence [40 CFR 98.1(b)].

The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of 40 CFR 98 apply to the owners and operators of any facility that is located in the United States and that contains any source category that is listed in Table A–3 of this subpart in any calendar year starting in 2010. For these facilities, the annual GHG report must cover stationary fuel combustion sources (subpart C of 40 CFR 98), miscellaneous use of carbonates (subpart U of 40 CFR 98), and all applicable source categories listed in Table A–3 and Table A–4 of this 40 CFR 98, Subpart A [40 CFR 98.2(a)(1)]. McIntosh Steam – Electric Generating Plant is considered an electricity generation unit that reports CO<sub>2</sub> mass emissions year round

through 40 CFR 75 (Subpart D) [Table A-3 of 40 CFR 98, Subpart A], and therefore subject to this regulation.

*Part 98, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 98) – Subpart C– General Stationary Fuel Combustion Sources*

Per 40 CFR 98.30(a), stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters. The startup boiler is subject to this regulation. This regulation is not applicable to electricity generating units that are subject to 40 CFR 98, Subpart D [40 CFR 98.30(b)(5)].

*Part 98, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 98) – Subpart D – Electricity Generation*

The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO<sub>2</sub> emissions year-round according to 40 CFR 75 [40 CFR 98.40(a)]. The steam generating unit and combustion turbines are therefore subject to this regulation. Per 40 CFR 98.43, McIntosh Steam – Electric Generating Plant must continue to monitor and report CO<sub>2</sub> mass emissions as required under 40 CFR 75.13 or Section 2.3 of Appendix G to 40 CFR 75, and 40 CFR 75.64. McIntosh Steam – Electric Generating Plant must calculate CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions by (1) converting the cumulative annual CO<sub>2</sub> mass emissions reported in the fourth quarter electronic data report required under 40 CFR 75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023, and (2) calculating and reporting annual CH<sub>4</sub> and N<sub>2</sub>O mass emissions by following the applicable method specified in 40 CFR 98.33(c).

*Georgia Rule 391-3-1-.02(2)(b) Emission Limitations and Standards Visible Emissions*

This rule limits opacity to less than forty (40) percent, except as may be provided in other more restrictive or specific rules or subdivisions of Georgia Rule 391-3-1-.02(2). This limitation applies to direct sources of emissions such as stationary structures, equipment, machinery, stacks, flues, pipes, exhausts, vents, tubes, chimneys or similar structures. These limitations may have been superseded by applicable PSD limits.

*Georgia Rule 391-3-1-.02(2)(d) Emission Limitations and Standards Fuel Burning Equipment*

This regulation limits particulate emissions from fuel burning equipment. For equipment under construction before January 1, 1972 with a rated capacity equal to or greater than 10 million BTU heat input per hour, and equal to or less than 2,000 million BTU heat input per hour, particulate emissions are limited to amounts equal to or exceeding the rate derived from  $P = 0.7(10/R)^{0.202}$  where R equals heat input rate in million Btu per hour and P equals the allowable emission rate in pounds per million Btu. This regulation is applicable to SG01. These limitations may have been superseded by applicable established permit emission limits.

For new equipment with a rated capacity equal to or greater than 10 million Btu heat input per hour, and equal to or less than 250 million Btu heat input per hour, particulate emissions are

limited to amounts equal to or exceeding the rate derived from  $P = 0.5(10/R)^{0.5}$  where R equals heat input rate in million Btu per hour and P equals the allowable emission rate in pounds per million Btu. This regulation also limits 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. These particulate matter and opacity limits are applicable to the startup boiler.

*Georgia Rule 391-3-1-.02(2)(g) Emission Limitations and Standards Sulfur Dioxide*

This rule requires that fuel-burning sources having a heat input of 100 million Btus per hour or greater shall not burn fuel containing more than 3.0 percent sulfur, by weight. This limitation is applicable to the steam generating unit and the combustion turbines. This limitation has been superseded by the applicable PSD limit for the combustion turbines.

All fuel burning sources below 100 million BTUs of heat input per hour shall not burn fuel containing more than 2.5 percent sulfur, by weight. This rule is applicable to the startup boiler. This limitation has been superseded by the applicable PSD limit for the startup boiler.

New fuel-burning sources capable of firing fossil fuels(s) at a rate of 250 million Btus per hour heat input cannot emit sulfur dioxide equal to or exceeding 0.8 pounds of sulfur dioxide per million Btus of heat input derived from liquid fossil fuel or derived from liquid fossil fuel and wood residue. This limitation is also applicable to the combustion turbines.

*Georgia Rule 391-3-1-.02(2)(n) – Fugitive Dust*

This regulation limits emissions from fugitive dust sources. The opacity from the coal and ash handling systems is limited to twenty (20) percent in accordance with Georgia Rule 391-3-1-.02(2)(n). These limitations may have been superseded by applicable PSD limits.

D. Compliance Status

Application 20540 does not indicate compliance issues for any equipment.

E. Operational Flexibility

None applicable.

F. Permit Conditions

The following permit modifications will be made as a result of the issuance of Permit Number 4911-103-0003-V-03-0:

- Permit Condition 3.2.1 was modified to allow approval of fire biodiesel or biodiesel blends for the same purposes as fuel oil in the steam generating unit SG01 per Georgia Power's request.
- Permit Condition 3.2.3 was modified to allow approval of fire biodiesel or biodiesel blends for the same purposes as fuel oil in the combustion turbines CT01 through CT08 per Georgia Power's request.



- Permit Condition 3.2.5 was modified to allow approval of fire biodiesel or biodiesel blends for the same purposes as fuel oil in the start-up boiler SB01 per Georgia Power's request.
- Permit Condition 3.3.2 was modified to allow approval to modify the language to be consistent with another Georgia Power facility concerning the maximum load per Georgia Power's request.
- Permit Condition 3.3.8 was modified to address general applicability of 40 CFR 63, Subpart DDDDD to the startup boiler.
- Permit Condition 3.3.9 was added to address general applicability of 40 CFR 63, Subpart UUUUU to the steam generating unit.

Permit Condition 3.2.1 limits the fuel usage for SG01.

Permit Condition 3.2.2 limits fuel usage for SG01 during startup and shutdown.

Permit Condition 3.2.3 limits the fuel usage for the combustion turbines.

Permit Condition 3.2.4 limits fuel usage of the combustion turbines based on annual heat input.

Permit Condition 3.2.5 limits the fuel usage for the startup boiler.

Permit Condition 3.3.1 limits NO<sub>x</sub>, CO, VOC, PM, and opacity emissions from the combustion turbines during fuel oil combustion.

Permit Condition 3.3.2 limits NO<sub>x</sub>, CO, VOC, PM, and opacity emissions from the combustion turbines during natural gas combustion.

Permit Condition 3.3.3 limits the sulfur content of the fuel oil fired in the combustion turbines.

Permit Condition 3.3.4 addresses the general applicability of 40 CFR 60, Subpart GG to the combustion turbines.

Permit Condition 3.3.5 limits the opacity from the coal handling system.

Permit Condition 3.3.6 limits the annual average sulfur content of the fuel oil burned in the combustion turbines.

Permit Condition 3.3.7 addresses the general applicability of 40 CFR 63, Subpart YYYY to the combustion turbines.

Permit Condition 3.3.8 addresses the general applicability of 40 CFR 63, Subpart DDDDD to the startup boiler.

Permit Condition 3.3.9 addresses the general applicability of 40 CFR 63, Subpart UUUUU to the steam generating unit.

Permit Condition 3.4.1 limits PM emissions from SG01.

Permit Condition 3.4.2 limits opacity from SG01.

Permit Condition 3.4.3 limits sulfur content of the fuel fired in SG01.

Permit Condition 3.4.4 requires Georgia Power to take all reasonable precautions with the coal handling system and the ash handling system to prevent fugitive dust.

Permit Condition 3.4.5 limits opacity from the ash handling system.

Permit Condition 3.4.6 limits PM emissions from the startup boiler.

Permit Condition 3.4.7 limits the opacity emissions from the startup boiler.

Permit Condition 3.4.8 limits the sulfur content of the fuel fired in the startup boiler.

#### 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.

##### B. Specific Testing Requirements

###### 1. Individual Equipment

Per the narrative associated with Permit Number 4911-103-0003-V-01-0, SG01 is required to be tested, at approximately one year intervals, for PM emissions. This testing requirement was in the facility's previous permit. The Permittee may request that the testing be deferred for a period of no greater than 12 months from the required annual test date if the previous annual tests showed PM emissions fifty percent or less of the limitation.

###### 2. Equipment Groups (all subject to the same test requirements):

Tests, for emissions of nitrogen oxides and carbon monoxide, are required on the combustion turbines (while combusting natural gas and while combusting fuel oil), per the narrative associated with Permit Number 4911-103-0003-V-01-0. The tests are required to be conducted at the earlier of 3000 operating hours or 5 years.

Per Permit Number 4911-103-0003-V-02-2, Permit Condition 4.1.3 was updated to include test methods ASTM D4629 and D3228 to determine No. 2 fuel oil nitrogen content.

## 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

#### 1. Individual Equipment:

Steam Generating Unit 1 is a fossil fuel fired boiler, which is subject to Georgia Rule (b) for visible emissions, Georgia Rule (d) for particulate matter (PM) emissions, and Georgia Rule (g) for sulfur dioxide (fuel sulfur). Per the narrative associated with Permit Number 4911-103-0003-V-01-0, a Continuous Opacity Monitoring System (COMS) was required to be installed on SG01 by Georgia Rule 391-3-1-.02(6)(a)2(i). The COMS has been installed and the data will be used to assure compliance with the opacity standard as well as the PM standard. To assure compliance with the particulate standard, an Opacity Index Value was established for SG01. The Opacity Index Value is the opacity level at which particulate matter emissions would be expected to be at or near the allowable limit (0.18 pounds per million Btu) and was established by correlating test data from previous PM emissions tests with the corresponding opacity levels during the testing. The emissions test data represented moderate percentages of the allowable particulate matter emission rate (20-60 percent), and since no data were available at or near the PM emissions allowable limit, extrapolations were necessary in order to obtain the Opacity Index Value. However, based upon curve fit characteristics, it was believed that the extrapolations were reasonably accurate. An Opacity Index Value of 33 percent was chosen. Three-hour periods during which the average opacity exceeds the Opacity Index Value are designated as excursions and six-minute averages which are equal to or greater than 40 percent are specified as exceedances.

Per the narrative associated with Permit Number 4911-103-0003-V-01-0, sampling and analysis of the coal will be used to determine compliance with Georgia Rule (g). The coal is required to be sampled as bunkered and analyses is required to be done by appropriate ASTM methods. The facility is also permitted to burn used oil generated on site. Methods for sampling and analyzing the used oil are specified. Permit Number 4911-103-0003-V-01-3 modified Permit Condition 5.2.17 (formerly Permit Condition 5.2.18) which required that Plant McIntosh obtain a sample of as bunkered coal for analysis for sulfur content (% S), moisture content, and Gross Caloric Value (GCV) for each day or portion of a day that coal is burned in steam generating unit SG01. Plant McIntosh is not equipped with a coal sampling system; therefore, the permit condition allowed the use of the continuous SO<sub>2</sub> emissions monitoring system (CEMS) to determine the fuel sulfur content instead of an “as bunkered” coal analysis.

Per the narrative associated with Permit Number 4911-103-0003-V-01-0, analyses of coal, No. 2 fuel oil, and used oil burned in the steam generating unit were reported on a quarterly basis. However, submittal of analysis of coal is no longer required since the Title V Permit no longer requires an analysis of the coal. Permit record keeping and reporting requirements for verification of compliance with the sulfur content limit have been previously updated.

2. Equipment Groups (all subject to the same monitoring requirements):

Per the narrative associated with Permit Number 4911-103-0003-V-01-0, the combustion turbines do not have any pollution control equipment except water injection for control of nitrogen oxides. Emissions tests were conducted for carbon monoxide (CO), PM, and visible emissions on all turbines. The results showed that carbon monoxide emissions tend to increase as turbine load decreases (due to incomplete combustion) and the CO allowable limitation was exceeded below 50 megawatts (each turbine showed compliance with the carbon monoxide limit at loads greater than 50 megawatts). Based upon the emissions test results, megawatts was chosen as the parameter for monitoring turbine operation and a minimum load of 50 megawatts was chosen for each turbine as a trigger value for ensuring compliance with the CO emission limit. Tests results for PM and visible emissions showed compliance with the applicable limitations. Because natural gas and No. 2 fuel oil are clean burning fuels, it is unlikely that the VOC, visible or PM emissions allowable limitations will be exceeded; therefore, no monitoring is required for those pollutants.

Per the narrative associated with Permit Number 4911-103-0003-V-01-0, emissions tests (initial performance tests) to establish the ratio of water to fuel burned at which compliance with the nitrogen oxides emission limitations across the load range of each turbine have been conducted, as required by 40 CFR 60, Subpart GG. These ratios were required by this regulation to be used to determine excess emissions of nitrogen oxides and any one-hour average water-to-fuel ratio less than that needed to demonstrate compliance with the nitrogen oxides emission limit were required to be reported as excess emissions. This monitoring and reporting of excess emissions have been included in the permit. The fuel sulfur and nitrogen monitoring requirements in 40 CFR 60, Subpart GG were also included. Fuel oil sulfur and nitrogen content are to be determined daily. Natural gas sulfur content is determined by semiannual supplier analysis (custom schedule approved under 40 CFR 60.334(b)(2)). Regulation 40 CFR 60, Subpart GG has been revised since the initial issuance of the Permit Number 4911-103-0003-V-01-0. Any changes in monitoring requirements have been previously updated to reflect such changes.

Records of all actions taken to prevent fugitive dust from the Coal Handling System (CHS) and the Ash Handling System (AHS) are required to be maintained.

### C. Compliance Assurance Monitoring (CAM)

The ESP (Source Code EP01) meets the definition of a control device as defined in 40 CFR 64.1. In addition, SG01 is subject to a particulate matter emission standard. The worst-case uncontrolled particulate emissions for Steam Generator Unit SG01 exceed 316 tons per year. The 40 CFR 64 applicability threshold, in this case, for particulate emissions is 100 tons per year. Thus, SG01 is a 40 CFR 64 *Pollutant Specific Emission Unit* (PSEU) for particulate emissions. The existing Title V Permit for McIntosh Steam – Electric Generating Plant does not define a *continuous compliance determination method* for the particulate emissions limitation for the steam-generating unit. Thus, McIntosh Steam – Electric Generating Plant is not exempt from the requirements of Part 64 for Particulate Emissions. With that in mind, Steam Generator Unit SG01 is subject to Part 64 for Particulate Emissions.

The Water Injection (WI's) Control Devices (Source Codes WII through WI8) meet the definition of a control device as defined in 40 CFR 64.1. In addition, Combine Turbine Units CT01 through CT08 are subject to a nitrogen oxides emission standard. The uncontrolled nitrogen oxides emissions from the combustion turbines exceed 596 tons per year. The 40 CFR 64 applicability threshold, in this case, for nitrogen oxides emissions is 100 tons per year. Thus, CT01 through CT08 are each a 40 CFR 64 PSEU for nitrogen oxides emissions. As with particulate emissions, the existing Title V Permit for McIntosh Steam – Electric Generating Plant does not define a *continuous compliance determination method* for the nitrogen oxides emissions limitation for each combustion turbine unit. Thus, McIntosh Steam – Electric Generating Plant is not exempt from the requirements of 40 CFR 64 for nitrogen oxides emissions. Combustion Turbine Units CT01 through CT08 are subject to 40 CFR 64 for nitrogen oxides emissions.

The requirements of 40 CFR 64 do not apply to the Coal Handling System (CHS) or the Ash Handling System (AHS) because these units are not equipped with control devices as defined in 40 CFR 64.1.

McIntosh Steam – Electric Generating Plant identified nine PSEUs that are subject to CAM in their CAM plan. They are listed in Condition 5.2.3 and are, as follows, with their specific pollutant(s) and control devices:

<b>Emission Unit</b>	<b>Pollutant</b>
CT01	Nitrogen Oxides
CT02	Nitrogen Oxides
CT03	Nitrogen Oxides
CT04	Nitrogen Oxides
CT05	Nitrogen Oxides
CT06	Nitrogen Oxides
CT07	Nitrogen Oxides
CT08	Nitrogen Oxides
SG01	Particulate Matter

As the controlled potential to emit of particulate emissions from SG01 and controlled nitrogen oxides emissions from Combustion Turbine Units CT01 through CT08 are greater than 100 tons per year, the required 40 CFR 64 data collection frequency is defined by 40 CFR 64.3(b)(4)(ii). This portion of the CAM regulation requires Georgia Power 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 Generator Unit 1 is controlled by an ESP (Source Code EP01). The primary indicator of proper control device operation for particulate matter is a continuous opacity monitoring system (COMS). It has been determined that the opacity cap level indicating unacceptable performance is a three-hour average of 28% opacity.

Combustion Turbine Units 1 through 8 are each controlled by a Water Injection System (Source Codes WI1 through WI8). The primary indicator of proper control device operation for nitrogen oxides is the continuous measurement of the water/fuel flow ratio. It has been determined that the water/fuel ratio cap levels indicating unacceptable performance is when the water-to-fuel ratio falls below the water-to-fuel ratio determined to demonstrate compliance with the applicable nitrogen oxides emissions permit limits.

Permit Condition 5.2.2 was a reserved condition and has been removed as a result of Permit Number 4911-103-0003-V-03-0. Subsequent permit conditions in Section 5.2 have been renumbered as a result of this modification.

## 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). These changes were included in Permit Number 4911-103-0003-V-02-4.

### B. Specific Record Keeping and Reporting Requirements

Per the narrative associated with Permit Number 4911-103-0003-V-01-0, Georgia Power has to maintain monthly records of all fuels burned in SG01. Georgia Power is also required to keep records 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 sawdust were burned, the sawdust would typically be spread 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.

Per the narrative associated with Permit Number 4911-103-0003-V-01-0, Georgia Power must 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 was expected that these values would not change much during the term of the permit. As long as these values do not change significantly, Georgia Power need only maintain one representative record of each such value. According to the narrative associated with Permit Number 4911-103-0003-V-01-0, since this is a State Only Enforceable Condition, and EPD has a high level of confidence that Savannah Electric (the previous facility owner) would keep acceptable records on the percent ash content, thresholds for recording new values were not included. Ash content records provided by Southern Company indicated that the ash content ranges from 5.7% to 9.6%. According to the narrative associated with Permit Number 4911-103-0003-V-01-0, EPD would be satisfied if then owner Savannah Electric kept an average or “representative” value (presumably around 7-7.5%) and then noted any occurrences above 10%.

Plant McIntosh is required to maintain records of fuel consumption, both fuel oil and natural gas, in each combustion turbine. The facility is then required, to report their fuel usage on a quarterly basis.



The following permit modifications will be made as a result of the issuance of Permit Number 4911-103-0003-V-03-0:

- Permit Condition 6.2.1 was modified to allow approval of fire biodiesel or biodiesel blends for the same purposes as fuel oil in the steam generating unit SG01 per Georgia Power's request. In addition 6.2.1b. was modified to include 'aggregate' when monitoring the quantity of fuel burned.
- Permit Condition 6.2.7 was modified to allow fuel oil to be certified to ASTM D975 as an alternative to ASTM D396 and for fuel oil certification of biodiesel or biodiesel blends.

**VII. Specific Requirements**

## A. Operational Flexibility

Not Applicable.

## B. Alternative Requirements

Not Applicable.

## 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

Not Applicable.

## E. Short-Term Activities

McIntosh Steam – Electric Generating Plant has the following short-term activities; sand blasting for maintenance purposes and asbestos removal in accordance with Georgia Rule 391-3-1-.02(9)(b)7. See Form D5 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, sand blasting is 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

Application Number 20540 does not indicate a compliance schedule/progress reports.

## G. Emissions Trading

Not Applicable.

#### H. Acid Rain Requirements

The facility is subject to acid rain requirements. Title IV conditions are included in the permit.

Permit Amendment 4911-103-0003-V-02-1 updated the Title IV Acid Rain Program Phase II NO<sub>x</sub> averaging plan for years 2009 to 2013 for Emission Unit SG01 in Condition 7.9.7 and Attachment D.

#### I. Stratospheric Ozone Protection Requirements

The standard permit condition pursuant to 40 CFR 82 Subpart F is included in Permit No. 4911-103-0003-V-03-0. 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. The facility does have air conditioners or refrigeration equipment that contain such substances. The facility does not maintain service, repair, or disposes of any motor vehicle air conditioners or appliances and therefore not subject to 40 CFR Part 82, Subpart B.

#### J. Pollution Prevention

Not Applicable.

#### K. Specific Conditions

Not Applicable

#### L. Clean Air Interstate (CAIR) Requirements

Per Permit Amendment 4911-103-0003-V-02-3, Condition 7.15.1 required 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 required the facility to comply with the CAIR facility wide annual NO<sub>x</sub> allowance allocations in accordance with 40 CFR 96 and Georgia Rule 391-3-1-.02(12).

The CAIR NO<sub>x</sub> allowances had been determined by the Division based on historical operating data for each equipment. Per Permit 4911-103-0003-V-03-0, 2012 and 2013 allowance allocations have been updated.

**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. Permit Amendment 4911-103-0003-V-02-4 included such changes.

**Addendum to Narrative**

The 30-day public review started on June 5, 2012 and ended on July 5, 2012. Comments were received by the Division from Georgia Power and GreenLaw.

**Georgia Power Comments**

Georgia Power submitted comments in a letter dated July 3, 2012 which was received by the Division on July 5, 2012. The following are Georgia Power's comments and the Division's responses to those comments:

**Georgia Power Comment #1:**

- 1. Condition 3.2.1** – Georgia Power requests to clarify the language in this condition to be consistent with other Title V operating permits.

*The Permittee shall not fire any fuel other than coal in the steam generating unit (Emission Unit ID SG01) except for the following:*

*[391-3-1-.03(2)(c)]*

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

**Division Response to Georgia Power Comment #1:**

The Division will make the following permit revisions:

- 3.2.1 The Permittee shall not fire any fuel other than coal in the steam generating unit (Emission Unit ID SG01) except for the following:  
[391-3-1-.03(2)(c)]
- a. No. 2 fuel oil, biodiesel, or biodiesel blends may be burned during start-up, and 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.

Georgia Power Comment #2:

2. **Condition 5.2.2** – Georgia Power requests to clarify the language in this condition so that it accurately describes the specified emission units.

*The Permittee shall determine the electrical output (MW) for each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) for each hour of operation. For the purposes of this permit, each hour of combustion turbine operation shall begin on the clock hour.*  
[40 CFR 70.6(a)(3)(i)]

Division Response to Georgia Power Comment #2:

The Division will make the following permit revisions:

- 5.2.2 The Permittee shall determine the electrical output (MW) for each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) for each hour of operation. For the purposes of this permit, each hour of combustion turbine operation shall begin on the clock hour.  
[40 CFR 70.6(a)(3)(i)]

Georgia Power Comment #3:

3. **Condition 6.1.7** – Georgia Power requests to clarify the language in this condition to be consistent with other Title V operating permits.

*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)(iii)]

- 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)*
- ii. *Any unit operating hour during which the monitoring system required in Condition 5.2.1c, falls below the water-to-fuel ratio determined to demonstrate compliance with the limits in Conditions 3.3.1a and 3.3.2a. The water-to-fuel ratio determined to demonstrate compliance at the load (Megawatts) at which the turbine is being operated shall be based upon the correlation established during the most recent performance test approved by the Division. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.*  
[40 CFR 60.334(j)(1)]

Division Response to Georgia Power Comment #3:

The Division will make the following permit revisions:

- 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)(iii)]
- 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. Any period during which the sulfur content of the fuel oil burned in the combustion turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) exceeds 0.5 percent sulfur by weight, as indicated by the sulfur analysis required by Condition 5.2.19b.  
[40 CFR 60.334(j)(2)]
    - ii. Any unit operating hour during which the monitoring system required in Condition 5.2.1c, falls below the water-to-fuel ratio determined to demonstrate compliance with the limits in Conditions 3.3.1a and 3.3.2a. The water-to-fuel ratio determined to demonstrate compliance at the load (Megawatts) at which the turbine is being operated shall be based upon the correlation established during the most recent performance test approved by the Division. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.  
[40 CFR 60.334(j)(1)]
  - 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. For Unit 1 (Emission Unit ID SG01), any twenty-four hour block average during which the arithmetic average coal sulfur content, as determined in accordance with Condition 6.2.4, exceeds 3.0 percent. A twenty-four hour block average shall be defined as a twenty-four hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire twenty-four hour period.

- ii. For each combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08), any annual average fuel oil sulfur content, as determined in accordance with Condition 3.3.6, which exceeds 0.05 percent by weight. For purposes of this condition, an annual period is represented by a calendar year.  
[40 CFR 52.21]
  - iii. Any time fuel is fired in the startup boiler (Emission Unit ID SB01) that has a sulfur content which exceeds 2.5 percent sulfur, by weight.
  - iv. Any six-minute period during which the average opacity, as measured by the COMS for the steam generating unit (Emission Unit ID SG01) exceeds 40 percent.
- 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 Unit 1 (Emission Unit ID SG01), any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 28 percent (for combustion of fuel which does not include Pine Branch coal) or 22.5 percent (for combustion of fuel which includes Pine Branch coal). 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.
  - ii. Any period of time greater than 3 hours in which any combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) is operated below 50 MW.
  - iii. Any period during which the fuel-bound nitrogen of the fuel oil burned in the combustion turbines (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) is greater than 0.06 percent by weight.  
[40 CFR 60.334(c)(1)]
- d. In addition to the excess emissions, exceedances and excursions specified above, the following should also be included with the report required in Condition 6.1.4:
- i. The Permittee shall submit written reports to the Division of the analyses of the fuel oil and used oil burned in Steam Generating Unit 1 (Emission Unit ID SG01). Reports shall be submitted for each quarter ending on March 31, June 30, September 30, and December 31, and records shall be submitted along with the quarterly reports required in Condition 6.1.4.  
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]



- ii. The Permittee shall submit written reports to the Division which specify the twenty-four hour block arithmetic average coal sulfur content for the steam generating unit (Emission Unit ID SG01) for each day in the reporting period. Reports shall be submitted for each quarter ending on March 31, June 30, September 30, and December 31, and records shall be submitted along with the quarterly reports required in Condition 6.1.4.  
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]
- iii. The Permittee shall submit to the Division a written report showing the quantities of fuel oil and natural gas consumed by each turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08) and the combined heat input from the consumption of such fuels in each turbine for every calendar quarter. Reports shall be submitted for each quarter ending on March 31, June 30, September 30, and December 31, and records shall be submitted along with the quarterly reports required in Condition 6.1.4.  
[40 CFR 52.21]

Georgia Power Comment #4:

- 4. Condition 8.28.1** – Georgia Power requests to remove this condition from the Title V permit. Plant McIntosh is not an area source therefore, Condition 8.28.1 is not applicable.

Division Response to Georgia Power Comment #4:

The Division will not remove Permit Condition 8.28.1 as it distinctly states that a source must demonstrate compliance with *applicable* provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63 Subpart A-"General Provisions" and 40 CFR 63 Subpart JJJJJ-"National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers." The Division agrees that Plant McIntosh Steam – Electric Generating Plant is not an area source. Therefore, as Permit Condition 8.28.1 states, Plant McIntosh Steam – Electric Generating Plant would only have to comply with this regulation if it were applicable. Therefore, the Division deems the removal of Permit Condition 8.28.1 unnecessary. However, the Division will update the citation in this condition to 40 CFR 63.11193.

**GreenLaw Comments**

GreenLaw submitted comments via email dated July 5, 2012 which was received by the Division on July 5, 2012. Please refer to Division's permit file for the entire copy of the comments received (16 pages) from GreenLaw. The following are GreenLaw's comments (only headings are listed below) and Division's responses to those comments:

GreenLaw Comment:

**I. Background**

Division Response to GreenLaw Comment:

Comment so noted.

GreenLaw Comment:**II. Regulatory Framework**Division Response to GreenLaw Comment:

Comment so noted.

GreenLaw Comment:**III. The Draft Permit is Incomplete**Division Response to GreenLaw Comment:

Comment so noted.

GreenLaw Comment:**IV. Emission Standards****a. Heat Inputs**Division Response to GreenLaw Comment:

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.

GreenLaw Comment:**b. Fuel Flexibility**Division Response to GreenLaw Comment:

The steam generating unit 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 Opacity Monitoring Systems (COMS) for visible emissions on the steam generating unit. This continuous monitoring system will ensure that the facility can comply with the opacity 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 has already been added in Condition 3.2.2.

GreenLaw Comment:

**c. Particulate Matter**

**i. The PM limit Should be Significantly Lowered**

Division Response to GreenLaw Comment:

It should be noted that Plant McIntosh has only *one* steam generating unit, not two as the commenter states. As stated before, the steam generating unit 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<sub>10</sub> and PM<sub>2.5</sub> emissions limits in this Title V Operating Permit.

GreenLaw Comment:

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

Division Response to GreenLaw Comment:

This facility is not currently subject to any PM<sub>2.5</sub> emissions standards or limits (applicable requirements). Permit Condition 3.4.1 subjects the steam generating unit to a particulate matter (PM) limit of 0.18 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<sub>2.5</sub> emissions limit.

GreenLaw Comment:

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

Division Response to GreenLaw Comment:

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 NO<sub>x</sub> 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.

GreenLaw Comment:**V. Excess Emissions****a. Condition 8.14.4 Should Not Include an Affirmative Defense**Division Response to GreenLaw Comment:

The excess emissions provisions come directly from Georgia Rule 391-3-1-.02(2)(a)7.

GreenLaw Comment:**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**Division Response to GreenLaw Comment:

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 McIntosh 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.

GreenLaw Comment:**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**

Division Response to GreenLaw Comment:

Please refer to the Division's response to Comment IV.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.

GreenLaw Comment:

- d. Condition 8.14.4 must be revised to address National Emissions Standards for Hazardous Air Pollutants.**

Division Response to GreenLaw Comment:

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 3.3.9 is added to include the general requirements for the EGU MACT, as applicable, to the Steam Generating Unit SG01.

GreenLaw Comment:**VI. 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**Division Response to GreenLaw Comment:

There is no regulatory requirement in 40 CFR 70 to require this facility to install PM CEMS on Steam Generating Unit SG01. 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.

GreenLaw Comment:**VII. Coal Handling System**

Division Response to GreenLaw Comment:

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 40 CFR 60, Subpart Y and Georgia Rule (n). The facility must comply with Permit Condition No. 6.2.2 that requires the facility to maintain a record of all actions taken in accordance with Permit Condition No. 3.4.4 to suppress fugitive dust from the coal handling system (Source Code: CHS) and the ash handling system (Source Code: AHS).

GreenLaw Comment:**VIII. Greenhouse Gas Monitoring and Reporting**Division Response to GreenLaw Comment:

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.

GreenLaw Comment:**IX. Hazardous Air Pollutants**Division Response to GreenLaw Comment:

Since the EGU Utility MACT (40 CFR 63 Subpart UUUUU) has become effective on April 16, 2012, Condition 3.3.9 is added to include the general requirements for the EGU MACT to the Steam Generating Unit SG01. The compliance date for Steam Generating Unit SG01 is April 16, 2015. Therefore, EPD will add any necessary conditions for EGU MACT in a permit amendment in the future.

**EPD Changes**

The Division modified Permit Condition 3.2.2 to indicate that it is only State Enforceable. The permit condition was modified as follows:

- State Only Enforceable Condition**
- 3.2.2 The Permittee shall not burn used oil in any steam generating unit (Emission Unit ID SG01) 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 shall be defined as the cessation of the operation of a source or facility for any purpose.  
[391-3-1-.03(2)(c)]

The Division also modified Permit Condition 3.3.1 to fully define nitrogen content of the fuel. The permit condition was modified as follows:

- 3.3.1 The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine (Emission Unit IDs CT01, CT02, CT03, CT04, CT05, CT06, CT07, and CT08), when burning fuel oil in the turbine, any gases which:  
[40 CFR 52.21(j) and 40 CFR 60.332(a) subsumed]
- a. Contain nitrogen oxides in excess of that allowed by the following equation:

$$\text{STD} = 0.0042 + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis)

F = NOx emission allowance for fuel-bound nitrogen defined by the following table:

Fuel-bound nitrogen (% by wt.)	F (NOx % by volume)
$N \leq \text{or} = 0.015$	0
$0.015 < N \leq \text{or} = 0.06$	0.04(N)
$N > 0.06$	0.0024

where: N = the nitrogen content of the fuel (% by wt.)

- b. Contain carbon monoxide in excess of the following rates:
- 9 ppmvd at a load factor of 100% load or greater.
  - $\text{CO} = -4.72 \times (\text{LF}\%) + 481$ ; for load factors greater than or equal to 75% load and less than 100% load.

- iii.  $CO = -8.92 \times (LF\%) + 796$ ; for load factors greater than or equal to 50% load and less than 75% load.
- iv. 350 ppmvd at loads below a load factor of 50% load.

Where CO equals the allowable carbon monoxide emission rate in ppmvd and LF% equals the load factor percentage with 100 corresponding to 100% load, defined as the maximum load achieved during the testing of the unit.

- c. Contain particulate matter in excess of 0.012 pound per million Btu heat input.
- d. Contain volatile organic compounds, as carbon, in excess of 30 ppm when the load factor is less than 75% and 11 ppm when the load factor is equal to or greater than 75%.
- e. Exhibit greater than 10 percent opacity.

In addition, the Division has revised the permit to add the applicability of *Georgia Rule 391-3-1-.02(2)(sss) Multipollutant Control for Electric Utility Steam Generating Units* which was inadvertently omitted from draft permit. Effective January 1, 2018, this regulation requires Georgia Power to evaluate the economic and technical feasibility of additional mercury controls on Plant McIntosh's Unit 1 and submit a report on the findings to the Division no later than September 1 of the calendar year following the calendar year that the annual heat input of Plant McIntosh's Unit 1 exceeds 14,557,638 million Btu [391-3-1-.02(2)(sss)16.] As a result, Table 3.1 of Permit 4911-103-0003-V-03-0 has been updated to include the applicability of this regulation to Source SG01 and reference Permit Condition 3.4.9 which will be added to the permit to include the requirements of this regulation.



# EXHIBIT D



## Region 4: Proposed Title V Permits

Last updated on Monday, November 05, 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	Effingham	Georgia Power Company - Plant McIntosh	4911-103-0003-V-03-0	9/14/2012	11/13/2012
GA	Laurens	Griffin Industries, LLC - East Dublin	2077-175-0042-V-03-0	9/22/2012	11/21/2012
GA	Screven	King America Finishing, Inc.	2261-251-0008-V-04-0	11/5/2012	1/4/2013

#### Title V Permits Undergoing Parallel Review\*\*

State	County	Source Name	PA Permit Number	45-Day Review Ends (parallel)	Petition Deadline
GA	Taylor	Taylor County LFGTE Power Station	4911-269-0016-V-02-3	8/5/2012	11/2/2012
GA	Effingham	Georgia-Pacific Consumer Products LP (Savannah River Mill)	2621-103-0007-V-04-0	8/8/2012	11/5/2012
GA	Hall	SAPA Extruder, Inc.	3354-139-0075-V-04-0	8/8/2012	11/5/2012
GA	DeKalb	Marathon Petroleum Company LP - Doraville Terminal	5171-089-0120-V-03-0	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	Newton	FiberVisions Manufacturing Company	2824-217-0020-V-03-0	8/26/2012	11/23/2012
GA	Houston	Anchor Glass Container Corporation	3221-153-0014-V-04-0	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-01-0	9/5/2012	12/3/2012
GA	Lowndes	Bathcraft, Inc.	3088-185-0073-V-05-0	9/7/2012	12/5/2012
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
GA	Whitfield	Shaw Industries, Inc. - Plant 80	2273-313-0003-V-03-0	10/10/2012	1/7/2013
GA	Glascock	Thiele Kaolin Company - Reedy Creek Plant	3295-125-0001-V-03-0	10/10/2012	1/7/2013
GA	Crisp	Griffin Lumber Company	2421-081-0008-V-02-0	10/12/2012	1/9/2013
GA	DeKalb	Live Oak Landfill & Recycling Center	4953-089-0263-V-03-0	10/17/2012	1/14/2013
GA	Jackson	Huber Engineered Woods, LLC	2493-157-0014-V-03-0	11/4/2012	2/1/2013
GA	Chatham	Gulfstream Aerospace Corporation	3721-051-0046-V-03-0	11/7/2012	2/4/2013
GA	Richmond	Procter & Gamble Manufacturing Company - Augusta Plant	2841-245-0068-V-03-0	11/7/2012	2/4/2013
GA	Early	Georgia-Pacific Corporation - Cedar Springs Operations, LLC	2631-099-0001-V-03-0	11/11/2012	2/8/2013
GA	Liberty	Interstate Paper, LLC	2631-179-0001-V-02-3	11/14/2012	2/11/2013
GA	Houston	CEMEX Southeast, LLC	3241-153-0003-V-05-2	11/18/2012	2/15/2013
GA	Whitfield	Mohawk Industries, Inc.	2273-313-0096-V-03-0	11/29/2012	2/26/2013
GA	Upson	West Georgia Generating Facility	4911-293-0027-V-03-1	12/12/2012	3/11/2013
GA	Peach	Blue Bird Body Company	3713-225-0001-V-05-0	12/12/2012	3/11/2013
GA	Evans	Georgia-Pacific Wood Products LLC - Claxton Chip-N-Saw	2421-109-0008-V-03-0	12/16/2012	3/15/2013

\* **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	)	ID NO. 17-00001
SHAWVILLE GENERATING STATION	)	
DRAFT TITLE V/STATE OPERATING PERMIT	)	
IN CLEARFIELD COUNTY, PA	)	
	)	
ISSUED BY THE PENNSYLVANIA	)	
DEPARTMENT OF ENVIRONMENTAL PROTECTION	)	

**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<sup>1</sup> of 10 micrometers (or microns) or smaller will be denoted as PM10. Particles with aerodynamic diameters 2.5 micrometers or smaller

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<sup>1</sup> 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<sup>3</sup> 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 PM<sub>2.5</sub>. 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, PM<sub>10</sub>, and PM<sub>2.5</sub> 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.

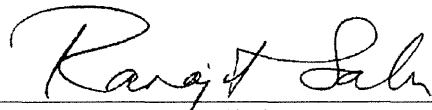
- Electrode cleaning. The effectiveness of dust removal from electrodes within the ESP.

- 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 possibly 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.



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Ranajit Sahu

Executed on February 14, 2011 in Alhambra, CA

**RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)**

**CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES**

**311 North Story Place**

**Alhambra, CA 91801**

**Phone: 626-382-0001**

**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).

"NO<sub>x</sub> Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Purchase 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.

- (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).