APPLICATION FOR AIR CONSTRUCTION PERMIT

JEA Northside Generating Station

Permit Application

Prepared For: JEA
21 West Church Street
Jacksonville, FL 32202

Submitted By: Golder Associates Inc.
6026 NW 1st Place
Gainesville, FL 32607 USA

Distribution: 4 copies – FDEP
2 copies – JEA
1 copy – Golder Associates Inc.

January 2012

113-87543

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Golder Associates

APPLICATION FOR AIR PERMIT

LONG FORM

Department of Environmental Protection

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DIVISION OF AIR RESOURCE MANAGEMENT

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **JEA**	
2. Site Name: **Northside Generating Station (NGS)**	
3. Facility Identification Number: **0310045**	
4. Facility Location... Street Address or Other Locator: **4377 Heckscher Drive** City: **Jacksonville** County: **Duval** Zip Code: **32226**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Facility Contact Name: **N. Bert Gianazza, P.E.**
2. Facility Contact Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **32202**
3. Facility Contact Telephone Numbers: Telephone: **(904) 665-6247** ext. Fax: **(904) 665-7376**
4. Facility Contact E-mail Address: **Giannb@jea.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 1-13-11	3. PSD Number (if applicable):
2. Project Number(s): 0310045-034-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Application for an air construction permit to allow biomass (wood chips from tree trimmings and similar plant materials) firing up to 300 tons per day (TPD) for each of the Northside Generating Station (NGS) Boiler Nos. 1 and 2 (EU IDs 027 and 026).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
027	NGS Boiler No. 1	AC1B	N/A
026	NGS Boiler No. 2	AC1B	N/A

Application Processing Fee

Check one: ☐ Attached - Amount: $______________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : James M. Chansler, P.E., D.P.A., Chief Operating Officer
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202
3.	Owner/Authorized Representative Telephone Numbers... Telephone: (904) 665 - 4433 ext. Fax: (904) 665 - 7990
4.	Owner/Authorized Representative E-mail Address: chanjm@jea.com
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* James M. Chansler Signature 11 Jan 12 Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source or CAIR source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official E-mail Address:

6. Application Responsible Official Certification:

I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

____________________ ________________
Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Kennard F. Kosky**
   Registration Number: **14996**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6026 NW 1st Place**
   City: **Gainesville** State: **FL** Zip Code: **32607**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext. **21156** Fax: **(352) 336-6603**
4. Professional Engineer E-mail Address: **Ken_Kosky@golder.com**
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Kennard F. Kosky — 1/12/12

Signature — Date

(seal) No. 14996 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **446.90** North (km) **3359.15**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **30/21/52** Longitude (DD/MM/SS) **81/37/25**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment : **The facility includes the NGS, St. Johns River Power Park (SJRPP), and the Separations Technology, LLC facility.**			

Facility Contact

1. Facility Contact Name: **N. Bert Gianazza, P.E.**
2. Facility Contact Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **32202**
3. Facility Contact Telephone Numbers: Telephone: **(904) 665-6247** ext. Fax: **(904) 665-7376**
4. Facility Contact E-mail Address: **Giannb@jea.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) ext. Fax: ( )
4. Facility Primary Responsible Official E-mail Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **NGS Boiler Nos. 1 and 2 are subject to NSPS 40 CFR 60 Subpart Da.**	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM/PM10/PM2.5	**A**	**N**
NOx	**A**	**N**
CO	**A**	**N**
VOC	**A**	**N**
SO2	**A**	**N**
Pb	**B**	**N**
SAM	**B**	**N**
HF	**B**	**N**
Hg	**B**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date: July 2008
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date: July 2008
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date: July 2008

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☐ Attached, Document ID:__________ ☒ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: Part II
3.	Rule Applicability Analysis: ☒ Attached, Document ID: Part II
4.	List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☐ Attached, Document ID:__________ ☒ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

1.	List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities: (Required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☐ Attached, Document ID:__________ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: **July 2008**
   ☐ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: **July 2008**
   ☐ Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: **July 2008**
   ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   NGS Circulating Fluidized Bed Boiler No. 2 (EU 026)
   NGS Circulating Fluidized Bed Boiler No. 1 (EU 027)

3. Emissions Unit Identification Number: **026, 027**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**02/02**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **297.5** MW

11. Emissions Unit Comment:
   Initial Startup Date for Boiler No. 2 was February 2002. Boiler No. 1 began commercial operation in May 2002.

Emissions Unit Control Equipment/Method: Control 1 of 4

1. Control Equipment/Method Description: **Dry Limestone Injection**	
2. Control Device or Method Code: **041**	

Emissions Unit Control Equipment/Method: Control 2 of 4

1. Control Equipment/Method Description: **Spray Dryer Absorber (SDA) polishing scrubber**	
2. Control Device or Method Code: **013**	

Emissions Unit Control Equipment/Method: Control 3 of 4

1. Control Equipment/Method Description: **Selective Noncatalytic Reduction (SNCR) for NOx**	
2. Control Device or Method Code: **107**	

Emissions Unit Control Equipment/Method: Control 4 of 4

1. Control Equipment/Method Description: **Fabric Filter - Low Temperature (T < 180F)**	
2. Control Device or Method Code: **018**	

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **5,528** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input for each boiler is 2,764 MMBtu/hr.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **EU026 and EU027**	2. Emission Point Type Code: **2**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **NGS Boiler No. 2 (EU026) and Boiler No. 1 (EU027) share a common stack. The common stack contains two separate flues, one for each CFB boiler.**	

5. Discharge Type Code: **V**	6. Stack Height: **495** feet	7. Exit Diameter: **15** feet
8. Exit Temperature: **144**°F	9. Actual Volumetric Flow Rate: **700,000** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Each boiler exhausts through its own flue but through a common stack. Stack parameters are for each boiler.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Bituminous Coal; Coal and coal treated with a latex binder**		
2. Source Classification Code (SCC): **1-01-002-18**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **221.12**	5. Maximum Annual Rate: **1,937,011**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **8**	8. Maximum % Ash: **18**	9. Million Btu per SCC Unit: **25**
10. Segment Comment: **Total for both boilers based on 2,764 MMBtu/hr heat input rate for each boiler.**		

Segment Description and Rate: Segment 2 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Petroleum Coke**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **212.62**	5. Maximum Annual Rate: **1,862,511**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **8**	8. Maximum % Ash: **18**	9. Million Btu per SCC Unit: **26**
10. Segment Comment: **Total for both boilers based on 2,764 MMBtu/hr heat input rate for each boiler.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 3 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Landfill gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.012**	5. Maximum Annual Rate: **102.50**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**
10. Segment Comment: **195 cf/min x 60 min/hr = 0.0117 x 10^6 cf/hr** **0.0117 x 10^6 cf/hr x 8,760 hr/yr = 102.5 x 10^6 cf/yr** **Represents total landfill gas to both boilers.**		

Segment Description and Rate: Segment 4 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Natural Gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.62**	5. Maximum Annual Rate: **2,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 gr/100 scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,022**
10. Segment Comment: **Rates are total for both boilers.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 5 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boiler; Electric Generation; Distillate Fuel Oil - Grades 1 or 2 Oil**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **4.52**	5. Maximum Annual Rate: **3,432.8**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **140**
10. Segment Comment: **Rates are total for both boilers.**		

Segment Description and Rate: Segment 6 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boiler; Electric Generation; Wood/Bark Waste**		
2. Source Classification Code (SCC): **1-01-009-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **25**	5. Maximum Annual Rate: **219,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **16**
10. Segment Comment: **Rates are total for both boilers.** **Maximum daily rate = 300 tons/day/boiler.**		

EMISSIONS UNIT INFORMATION
Section [1]
NGS Boiler Nos. 1 and 2

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOx	107		EL
CO			EL
SO2	041	013	EL
VOC			EL
PM	018		EL
PM10	018		EL
Mercury (H114)	013	018	EL
PB	018		EL
SAM	041	013	EL
HF (H107)	013		EL
HAPs			NS
HCl (H106)	013		NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **46.5** lb/hour **203.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.22 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly = 9,600 MMBtu/day x day/24 hr x 0.22 lb/MMBtu x (1 – 47.2/100) = 46.5 lb/hr
Potential annual = 46.5 lb/hr x 8,760 hr/yr x ton/2,000 lb = 203.4 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:
The above emissions are for wood chip firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.09 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **498** lb/hour **2,180** tons/year
5. Method of Compliance: **Compliance with the NOx emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.6 lb/MMBtu**	4. Equivalent Allowable Emissions: **3,317** lb/hour **14,528** tons/year
5. Method of Compliance: **Compliance with the NOx emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 60, Subpart Da.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3,600 TPY**	4. Equivalent Allowable Emissions: lb/hour **3,600** tons/year
5. Method of Compliance: **Compliance with the NOx emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable to NGS Boiler Nos. 1, 2, and 3 (EU003) combined, 12-month rolling average.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **13.7** lb/hour **60.2** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.60 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Potential hourly = 9,600 MMBtu/day x day/24 hr x 0.6 lb/MMBtu x (1 – 94.3/100) = 13.7 lb/hr
Potential annual = 13.7 lb/hr x 8,760 hr/yr x ton/2,000 lb = 60.2 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:
The above emissions are for wood chip firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **350 lb/hr, 24-hr block, each boiler**	4. Equivalent Allowable Emissions: **700** lb/hour **3,066** tons/year
5. Method of Compliance: **Compliance with the CO emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3** lb/hour **13.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.025 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Potential hourly = 9,600 MMBtu/day x day/24 hr x 0.025 lb/MMBtu x (1 – 70/100) = 3 lb/hr
Potential annual = 3 lb/hr x 8,760 hr/yr x ton/2,000 lb = 13.1 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:
The above emissions are for wood chip firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu, 24-hr block average**	4. Equivalent Allowable Emissions: **1,106** lb/hour **4,843** tons/year
5. Method of Compliance: **Compliance with the SO_2 emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **829** lb/hour **3,632** tons/year
5. Method of Compliance: **Compliance with the SO_2 emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.6 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **3,317** lb/hour **12,284** tons/year
5. Method of Compliance: **Compliance with the SO_2 emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 60, Subpart Da.** **Represents total of both boilers.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **12,284 TPY**	4. Equivalent Allowable Emissions: lb/hour **12,284** tons/year
5. Method of Compliance: **Compliance with the SO_2 emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable to NGS Units 1, 2, and 3 combined, 12-month rolling average.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.8** lb/hour **29.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.017 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly = 9,600 MMBtu/day x day/24 hr x 0.017 lb/MMBtu = 6.8 lb/hr
Potential annual = 6.8 lb/hr x 8,760 hr/yr x ton/2,000 lb = 29.8 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:

The above emissions are for wood chip firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **14 lb/hr, 3-hour average, each boiler**	4. Equivalent Allowable Emissions: **28** lb/hour **123** tons/year
5. Method of Compliance: **Testing once in every five years using EPA Method 18, 25, or 25A. Compliance with CO limits based on CEMS data can be used as surrogate.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.28** lb/hour **1.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.117 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly = 9,600 MMBtu/day x day/24 hr x 0.117 lb/MMBtu x (1 – 99.4/100) = 0.28 lb/hr
Potential annual = 0.28 lb/hr x 8,760 hr/yr x ton/2,000 lb = 1.3 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:
The above emissions are for wood chip firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.011 lb/MMBtu, 3-hour average**	4. Equivalent Allowable Emissions: **61** lb/hour **266** tons/year
5. Method of Compliance: **Annual compliance tests using EPA Methods 5, 5B, 8, 17, or 29 while firing petroleum coke.**	
6. Allowable Emissions Comment (Description of Operating Method): **If petroleum coke has been fired for less than 100 hours during previous quarter or less than 400 hours during the previous federal fiscal year, the testing may be performed while firing coal.** **Represents total of both boilers. Permit No. 0310045-003-AC/PSD-FL-265.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **881 TPY**	4. Equivalent Allowable Emissions: lb/hour **881** tons/year
5. Method of Compliance: **Annual compliance tests using EPA Methods 5, 5B, 8, 17, or 29 while firing petroleum coke.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable to NGS Units 1, 2, and 3 combined, 12-month rolling average.** **Permit No. 0310045-003-AC/PSD-FL-265.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.22** lb/hour **1.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.091 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly = 9,600 MMBtu/day x day/24 hr x 0.091 lb/MMBtu x (1 – 99.4/100) = 0.22 lb/hr
Potential annual = 0.22 lb/hr x 8,760 hr/yr x ton/2,000 lb = 1.0 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:

The above emissions are for wood chip firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.011 lb/MMBtu, 3-hour average**	4. Equivalent Allowable Emissions: **61** lb/hour **266** tons/year
5. Method of Compliance: **Annual compliance tests using EPA Methods 5, 5B, 8, 17, or 29 while firing petroleum coke.**	
6. Allowable Emissions Comment (Description of Operating Method): **If petroleum coke has been fired for less than 100 hours during previous quarter or less than 400 hours during the previous federal fiscal year, the testing may be performed while firing coal. Represents total of both boilers. Permit No. 0310045-003-AC/PSD-FL-265.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Mercury**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.06** lb/hour **0.26** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.03 lb/hour (6-hour average), each boiler** Reference: **Permit No. 0310045-003-AC/PSD-FL-265**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Each unit: Annual mercury emissions rate: 0.03 lb/hr x 8,760 hr/yr x ton/2000 lb = 0.13 ton/yr**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are based on a 6-hour average and represent total for both boilers. Above emissions reflect existing emission limits for the units. Mercury emissions from biomass firing are expected to be zero.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>**Allowable Emissions**</u> Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.03 lb/hr, 6-hour average, each boiler**	4. Equivalent Allowable Emissions: **0.06** lb/hour **0.26** tons/year
5. Method of Compliance: **Initial testing using EPA Methods 29, 101, or 101A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

<u>**Allowable Emissions**</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>**Allowable Emissions**</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.14** lb/hour **0.62** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.07 lb/hour (3-hour average), each boiler** Reference: **Permit No. 0310045-003-AC/PSD-FL-265**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Each unit: Annual lead emissions rate: 0.07 lb/hr x 8,760 hr/yr x ton/2000 lb = 0.31 ton/yr**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are based on a 3-hour average and represent total for both boilers. Above emissions reflect existing limits for the units. Lead emissions from biomass firing are expected to be zero.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.07 lb/hr, 3-hour average, each boiler**	4. Equivalent Allowable Emissions: **0.14** lb/hour **0.62** tons/year
5. Method of Compliance: **Testing once every five years at Title V permit renewal on one of the units using EPA Method 12 or 29.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265. Represents total of both boilers.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.46** lb/hour **2.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0038 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly = 9,600 MMBtu/day x day/24 hr x 0.0038 lb/MMBtu x (1 – 70/100) = 0.46 lb/hr
Potential annual = 0.46 lb/hr x 8,760 hr/yr x ton/2,000 lb = 2.0 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:
The above emissions are for wood chip firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.1 lb/hr, 3-hour average, each boiler**	4. Equivalent Allowable Emissions: **2.2** lb/hour **9.64** tons/year
5. Method of Compliance: **Initial compliance test only using EPA Method 8. Compliance with SO_2 limits based on CEMS data can be used as a surrogate.**	
6. Allowable Emissions Comment (Description of Operating Method): **Continuous compliance is demonstrated by complying with the SO_2 limits based on CEMS data as surrogate.** **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Hydrogen Fluoride**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.86** lb/hour **3.76** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.43 lb/hour (3-hour average), each boiler** Reference: **Permit No. 0310045-003-AC/PSD-FL-265**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Each unit: Annual HF emissions rate: 0.43 lb/hr x 8,760 hr/yr x ton/2000 lb = 1.88 tons/yr**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are based on a 3-hour average and represent total for both boilers. Above emissions reflect existing limits for the units. HF emissions from biomass firing are expected to be zero.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.43 lb/hr, 3-hour average, each boiler**	4. Equivalent Allowable Emissions: **0.86** lb/hour **3.76** tons/year
5. Method of Compliance: **Initial compliance test only using EPA Method 13A or 13B.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265. Represents total of both boilers.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COMS**	
5. Visible Emissions Comment: **Rule 62-212.400, F.A.C; and Permit No. 0310045-03-AC/PSD-FL-265.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **COMS**	
5. Visible Emissions Comment: **40 CFR 60 Subpart Da.**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 6

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **KVB/MIP** Model Number: **LM3086EPA3**	Serial Number: **See Comment**
5. Installation Date: **7/14/2002 (Boiler No. 1)** **4/1/2002 (Boiler No. 2)**	6. Performance Specification Test Date: **10/14/2002 (Boiler No. 1)** **7/1/2002 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 730216** **Serial Number: NGS CFB Boiler No. 2: 730217**	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Thermo Scientific** Model Number: **48ITLE-ACPCB**	Serial Number: **See Comment**
5. Installation Date: **11/1/2009**	6. Performance Specification Test Date: **1/21/2010 (Boiler No. 1)** **1/7/2010 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 0819830961** **Serial Number: NGS CFB Boiler No. 2: 0819830960**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor 3 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42i**	Serial Number: **See Comment**
5. Installation Date: **11/1/2009**	6. Performance Specification Test Date: **1/21/2010 (Boiler No. 1)** **1/7/2010 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 0809828969** **Serial Number: NGS CFB Boiler No. 2: CM08030131**	

Continuous Monitoring System: Continuous Monitor 4 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **43i**	Serial Number: **See Comment**
5. Installation Date: **11/1/2009**	6. Performance Specification Test Date: **1/21/2010 (Boiler No. 1)** **1/7/2010 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: CM08030142** **Serial Number: NGS CFB Boiler No. 2: CM08030140**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor 5 of 6

1. Parameter Code: **CO2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **410i**	Serial Number: **See Comment**
5. Installation Date: **11/1/2009**	6. Performance Specification Test Date: **1/21/2010 (Boiler No. 1)** **1/7/2010 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 0800226818** **Serial Number: NGS CFB Boiler No. 2: 0800226813**	

Continuous Monitoring System: Continuous Monitor 6 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **Mercury**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Thermo Scientific** Model Number: **80I-ADFNCB**	Serial Number: **See Comment**
5. Installation Date: **September 12, 2008**	6. Performance Specification Test Date: **See Comment**
7. Continuous Monitor Comment: **Serial Number = NGS CFB Boiler No. 1: 0809128431** **Serial Number = NGS CFB Boiler No. 2: 0805028186** **Test Date: NGS CFB Boiler No. 1: June 23, 2009** **Test Date: NGS CFB Boiler No. 2: March 24, 2009** **Required per Permit No. 0310045-022-AC/PSD-FL-265E.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: JEA-EU1-I1 ☐ Previously Submitted, Date ____
2.	Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
3.	Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☒ Previously Submitted, Date July 2008
4.	Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☒ Previously Submitted, Date July 2008 ☐ Not Applicable (construction application)
5.	Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6.	Compliance Demonstration Reports/Records: ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute: ☐ Attached, Document ID: ____ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID: ______ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ______ ☒ Not Applicable	
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ______ ☒ Not Applicable	

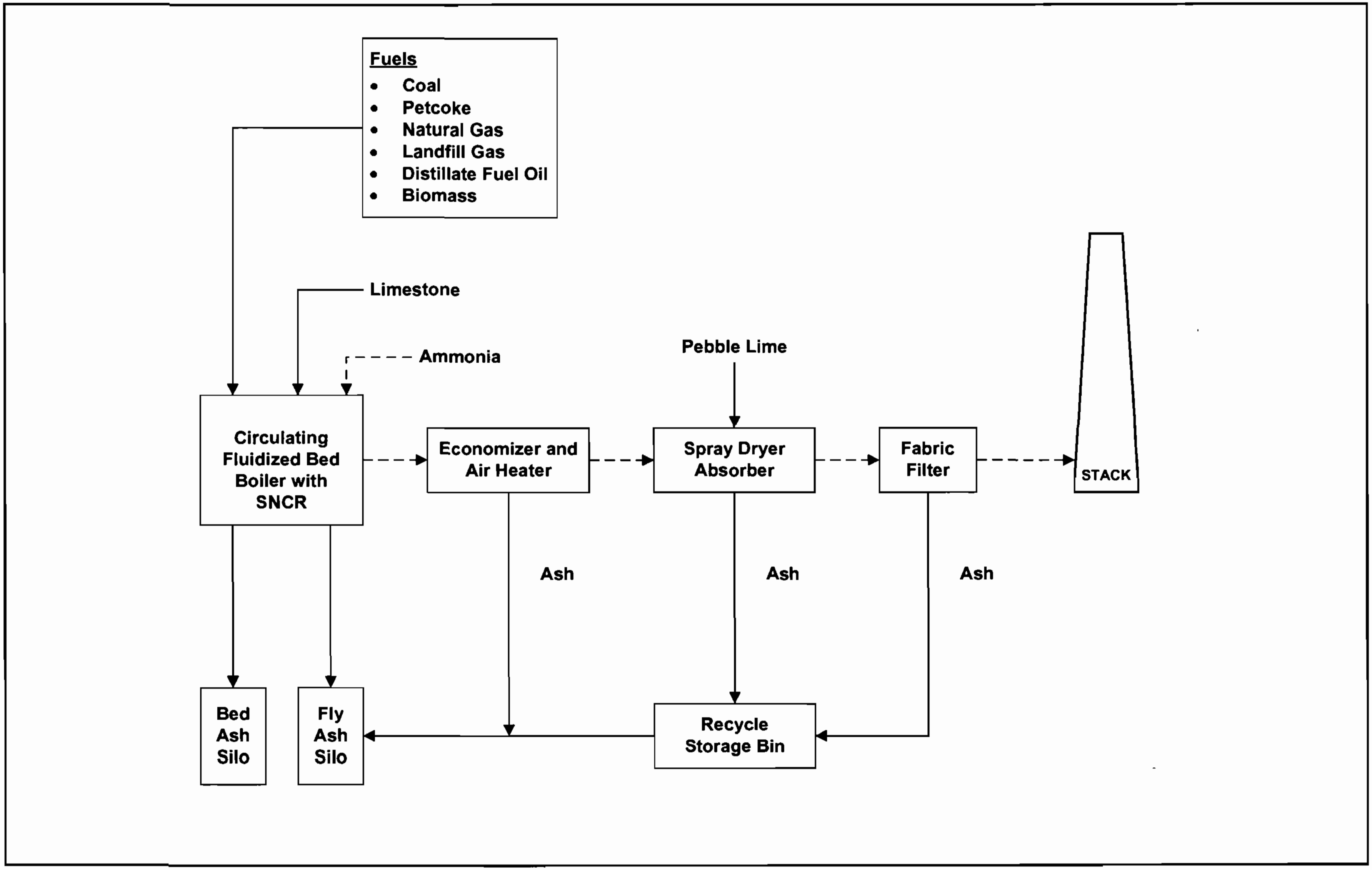
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☐ Attached, Document ID: ______	
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: ______ ☐ Not Applicable	
3. Alternative Methods of Operation: ☐ Attached, Document ID: ______ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: ______ ☐ Not Applicable	

Additional Requirements Comment

ATTACHMENT JEA-EU1-I1

PROCESS FLOW DIAGRAM



Attachment JEA-EU1-I1
Process Flow Diagram
Northside Generating Station Units 1 and 2

Process Flow Legend

Solid/Liquid ⟶
Gas - - - -▸

Golder Associates

PART II

PART II

APPLICATION FOR MINOR SOURCE AIR CONSTRUCTION PERMIT FOR BURNING BIOMASS IN NGS BOILER NOS. 1 AND 2 (EU IDS 027 AND 026)

EXECUTIVE SUMMARY

JEA is seeking authorization from the Florida Department of Environmental Protection (FDEP) to burn up to a maximum of 300 tons per day (TPD) of biomass (i.e., wood chips from tree trimmings and similar plant materials) in each of Northside Generating Station (NGS) Boiler Nos. 1 and 2 (EU IDs 027 and 026). FDEP recently authorized JEA to burn up to a maximum of 33.3 TPD of biomass in each of the same boilers (FDEP Project No. 0310045-032-AC authorized on October 10, 2011), which amounts to 1 percent of the heat input potential for both boilers. FDEP also determined that the biomass-burning project would have miniscule changes in emissions compared to the small and allowable day-to-day variations in the coal and petcoke and blend ratios, and therefore exempted the project from requiring an air construction permit. JEA's latest request is based on the demonstration in the tables attached with this document that the proposed biomass-firing is projected to decrease emissions of greenhouse gases (GHGs), and of all criteria pollutants except nitrogen oxides (NO_x) and volatile organic compounds (VOC), which are projected to increase. However, based on the current actual-to-future potential emissions test, the use of a maximum of 300 TPD of biomass per boiler will not result in a net increase of NO_x or VOC above the Prevention of Significant Deterioration (PSD) significant emission rate. There are no other changes in Boiler Nos. 1 and 2 as a result of this project.

The boilers are currently permitted to fire coal, coal treated with a latex binder, petroleum coke, No. 2 fuel oil, natural gas, and landfill gas from the adjacent North Landfill.

INTRODUCTION

The NGS is located at 4377 Heckscher Drive, Jacksonville, Duval County, Florida, and is adjacent to the St. Johns River Power Park (SJRPP) facility. Both facilities are covered under one Title V Permit (Final Title V Permit No. 0310045-030-AV).

Golder Associates Inc. (Golder) was contracted to prepare the necessary air permit application seeking authorization to burn biomass (from JEA's tree trimming activities) in NGS Boiler Nos. 1 and 2. This air construction permit application package consists of the appropriate application form [DEP Form 62-210.900(1)], a technical description of the project, and rule applicability for the project.

The maximum heat input rate for NGS Boiler Nos. 1 and 2 is 2,764 million British thermal units per hour (MMBtu/hr) for each boiler. JEA is proposing to burn a maximum of 300 TPD of biomass in each boiler. The actual heating value of the biomass is not available. However, Section 1.6 of AP-42, Wood Residue Combustion in Boilers, provide a range of heating values – from about 4,500 British thermal units per pound (Btu/lb) of fuel on a wet, as-fired basis to about 8,000 Btu/lb for dry wood. Using a conservative high estimate of 8,000 Btu/lb, the proposed wood chip firing will have the potential to replace a total of 9,600 MMBtu per day or 3,504,000 MMBtu per year of current actual heat input for both boilers. The project does not include any physical changes to the boiler units.

NO_x emissions from the NGS Boiler Nos. 1 and 2 are currently controlled by a selective non-catalytic reduction (SNCR) system installed on each boiler. Particulate matter (PM) emissions from the units are controlled by fabric filters, and sulfur dioxide (SO_2) emissions are controlled by limestone injection and a spray dryer absorber system. There will be no change to the existing control equipment as a result of the proposed project and no new emission control technology will be added.

RULE APPLICABILITY

Under Federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. The U.S. Environmental Protection Agency (EPA) has approved Florida's State Implementation Plan (SIP), which contains PSD regulations. The applicable PSD rules in Florida are found in Rule 62-212.400, Florida Administrative Code (F.A.C.).

A "major facility" is defined as any of 28 named source categories that have the potential to emit 100 tons per year (TPY) or more, or any other stationary facility that has the potential to emit 250 TPY or more, of any pollutant regulated under the CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in Title 40, Part 52.21 of the Code of Federal Regulations (40 CFR 52.21), Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted the federal PSD regulations by reference (Rule 62-212.400, F.A.C.). Major facilities and major modifications are required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts:

- Control technology review
- Source impact analysis
- Air quality analysis (monitoring)
- Source information
- Additional impact analyses

The NGS is part of the JEA NGS/SJRPP/Separations Technology (ST) facility complex, which is a major facility under FDEP rules. Based on Rule 62-210.200(205), F.A.C., modification is defined as any physical change in, change in the method of operation of, or addition to a facility which would result in an increase in the actual emissions of any pollutant subject to new source review regulation under the CAA. Because there is a change in the method of operation with the addition of biomass as a fuel for normal operation, the project is a potential modification as defined in the FDEP rules in Rule 62-210.200 and under the PSD rules in Rule 62-212.400, F.A.C. PSD review would be required for the project if there were a significant net increase in emissions.

NGS Boiler Nos. 1 and 2 are baseload electric generating units firing natural gas, No. 2 fuel oil, coal, petroleum coke, and landfill gas. Future operation of these primary fuels will not change. Since each boiler is rated at 2,764 MMBtu/hr of heat input and the proposed biomass fuel will have the potential to provide only 9,600 MMBtu/day heat input for both boilers, the primary heat input will be achieved by firing the currently permitted fuels. The daily heat input of 9,600 MMBtu/day achieved by biomass is only 7.2 percent of the daily heat input potential of 132,672 MMBtu/day for both boilers. Thus, only 7.2 percent of heat input obtained from firing currently permitted fuels will be replaced by firing biomass. To evaluate any potential increases in emissions, a comparison was made between future projected actual annual emissions resulting from 600 TPD of wood chip firing and the current actual annual emissions resulting from the maximum potential heat input to be replaced by biomass.

The baseline or current actual emissions are the emissions over a consecutive 24-month period within the 5 years immediately preceding the date that a complete application is submitted. The use of different consecutive 24-month periods for each pollutant is allowed. For an existing facility for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates for any applicable pollutant.

Table 1 presents the actual annual heat inputs for Boiler Nos. 1 and 2 resulting from different fuels reported in the Annual Operating Reports (AORs) for the period 2006 through 2010, as well as the actual operating hours for each unit. The table also presents individual fuel heat inputs as a percent of total heat input.

Table 2 summarizes the annual emissions for Boiler Nos. 1 and 2 reported in the AORs for each calendar year in the period 2006 through 2010. The carbon dioxide (CO_2) emission rates in Table 2 were obtained from EPA's Acid Rain database.

The actual emissions reported in AORs are presented as a function of heat input [pounds per million British thermal units (lb/MMBtu)] in Table 3. Emissions factors are presented for each individual boiler and also as an average rate for both Boiler Nos. 1 and 2.

Since emissions of nitrous oxide (N_2O) and methane (CH_4) were not reported in the AORs, they were calculated based on the actual annual heat input and emission factors from 40 CFR 98, Subpart C. These emissions are summarized in Table 4, which also shows the CO_2 equivalent (CO_2e) rates for these pollutants.

NO_x emissions from Boiler Nos. 1 and 2 are currently controlled by a SNCR system. PM emissions from the units are controlled by fabric filters, and SO_2 emissions are controlled by limestone injection and a spray dryer absorber system. The actual control efficiency of these controls are estimated in Table 5 by comparing the current actual emission factors to the uncontrolled emission factors from EPA's AP-42. For SO_2, since the uncontrolled emission factor was not readily available, a typical control efficiency of 70 percent was assumed. Sulfuric acid mist (SAM) emissions are also expected to be controlled at an efficiency similar to SO_2. For VOC, since the calculation indicated no decrease in actual emission factor, a control efficiency of 0 percent was assumed.

Table 6 presents the average emissions for each consecutive 2-year period based on the calendar year emissions in Table 3. The annual average emissions for each consecutive 2-year period are consistent with the definition of baseline actual emissions for fossil fuel-fired steam electric generating units.

Table 7 presents the future projected actual emissions due to wood chip firing. The potential annual heat input is based on maximum wood chip usage of 600 TPD for 365 days per year and using a heating value of 8,000 Btu/lb for dry wood. Emission factors used are from Section 1.6 of AP-42. PM emission factors include condensable PM assuming all condensable PM are in 2.5 micron ($PM_{2.5}$) size category. There are no emission factors available in AP-42 for SAM. The SAM emission rate was calculated assuming 10 percent of the SO_2 emissions will be oxidized into sulfur trioxide (SO_3), which will then convert to SAM through chemical reaction in the atmosphere. GHG emission factors for wood chip firing were obtained from Table C-2, Subpart C, 40 CFR 98. Initially the uncontrolled emission rates were calculated. The actual control efficiencies estimated in Table 5 were applied to the uncontrolled emission rates to estimate the future projected actual emission rates. Emission control efficiencies for VOC, SAM, and GHGs were assumed to be zero.

The PSD applicability analysis is presented in Table 8. The baseline emissions used are the maximum 2-year average emissions for each pollutant in Table 6. The actual emission factors in lb/MMBtu were obtained from Table 3. The actual emission factors for N_2O and CH_4 in CO_2e lb/MMBtu were estimated from the baseline emissions and maximum 2-year period average heat input. The actual emission factors are applied to the heat input due to wood chip firing to calculate current actual emissions that will be replaced by emissions due to wood chip firing. The current actual emissions were subtracted from the future projected actual emissions due to wood chip firing (from Table 7) and the difference was compared to the PSD significant emission rates for each pollutant.

As shown in Table 8, there will be a net decrease in all pollutants except NO_x and VOC. However, the increase in NO_x and VOC will be much lower than 40 TPY, which is the PSD significant emission rate for both pollutants. Table 8 also shows that the use of biomass will result in a significant decrease in GHG emissions. As a result, the proposed project is not subject to PSD and a minor source air construction permit application is applicable to the project.

There are additional benefits of burning tree trimmings in the boilers. Tree trimmings typically end up in a landfill, where they decompose to generate CH_4, a greenhouse gas that has global warming potential 21 times higher than CO_2. Therefore, burning it in the boilers will also reduce the CH_4 emissions that would have been generated from the decomposition of the biomass.

TABLES

Table 1. NGS Boiler Nos. 1 and 2 Annual Heat Inputs, 2006 - 2010

Year	Heat Input from Bituminous Coal (MMBtu/yr)			Heat Input from Distillate Oil (MMBtu/yr)			Heat Input from Natural Gas (MMBtu/yr)			Heat Input from Coke (MMBtu/yr)			Total Actual Heat Input (MMBtu/yr)			Actual Operating Hours (hr/yr)	
	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2
2010	1,644,874	1,722,358	3,367,232	0	0	0	34,304	24,720	59,024	15,357,748	16,661,805	32,019,553	17,036,926	18,408,883	35,445,809	6,816	7,177
2009	1,349,691	1,498,508	2,848,199	0	0	0	14,602	35,666	50,268	14,351,596	14,564,536	28,916,132	15,715,889	16,098,710	31,814,599	6,227	6,332
2008	1,698,226	1,488,040	3,186,266	0	0	0	70,283	46,200	116,483	17,798,191	15,357,664	33,155,855	19,566,700	16,891,904	36,458,604	7,940	6,885
2007	2,981,916	2,729,706	5,711,622	0	0	0	49,162	99,274	148,436	16,854,068	16,156,248	33,010,316	19,885,146	18,985,228	38,870,374	7,765	7,374
2006	2,781,275	3,284,308	6,065,583	0	0	0	51,156	52,479	103,635	14,596,540	14,969,108	29,565,648	17,428,971	18,305,895	35,734,866	7,105	7,411

Individual Fuel Heat Input as a Percent of Total Heat Input

Year	Heat Input from Bituminous Coal (MMBtu/yr)			Heat Input from Distillate Oil (MMBtu/yr)			Heat Input from Natural Gas (MMBtu/yr)			Heat Input from Coke (MMBtu/yr)		
	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total
2010	4.6%	4.9%	9.5%	0	0	0	0.1%	0.1%	0.2%	43.3%	47.0%	90.3%
2009	4.2%	4.7%	9.0%	0	0	0	0.0%	0.1%	0.2%	45.1%	45.8%	90.9%
2008	4.7%	4.1%	8.7%	0	0	0	0.2%	0.1%	0.3%	48.8%	42.1%	90.9%
2007	7.7%	7.0%	14.7%	0	0	0	0.1%	0.3%	0.4%	43.4%	41.6%	84.9%
2006	7.8%	9.2%	17.0%	0	0	0	0.1%	0.1%	0.3%	40.8%	41.9%	82.7%

Note: All values are based on annual operating reports for the period 2006 - 2010.

Table 2. Annual Emissions Reported in 2006-2010 Annual Operating Reports

Year	Pollutant	Boiler No. 1 (tons)	Boiler No. 2 (tons)	Total (tons)
2010	NO_x	704.0	902.7	1,606.7
	CO	302.2	200.3	502.5
	SO_2	1,584.2	1,607.5	3,191.7
	VOC	21.2	22.1	43.3
	PM	21.7	16.2	38.0
	PM_{10}	27.4	20.4	47.8
	SAM [a]	--	--	488.7
	CO_2	2,090,362.3	2,125,872.5	4,216,234.8
2009	NO_x	810.0	804.1	1,614.1
	CO	119.9	150.5	270.4
	SO_2	1,397.1	1,387.9	2,785.0
	VOC	19.6	20.0	39.6
	PM	18.7	29.0	47.7
	PM_{10}	17.5	27.0	44.5
	SAM [a]	--	--	426.5
	CO_2	1,922,135.5	1,948,776.2	3,870,911.7
2008	NO_x	818.7	701.2	1,519.9
	CO	203.4	125.0	328.4
	SO_2	1,565.0	1,565.0	3,130.0
	VOC	24.6	21.2	45.9
	PM	26.4	33.5	59.8
	PM_{10}	18.9	22.9	41.8
	SAM [a]	--	--	479.3
	CO_2	2,278,188.9	1,828,111.5	4,106,300.4
2007	NO_x	724.6	719.3	1,443.9
	CO	256.8	329.5	586.3
	SO_2	1,510.5	1,411.7	2,922.2
	VOC	24.7	23.0	47.8
	PM	10.3	37.6	47.9
	PM_{10}	10.1	28.0	38.1
	SAM [a]	--	--	447.5
	CO_2	2,295,968.3	2,100,239.5	4,396,207.8
2006	NO_x	710.0	782.0	1,492.0
	CO	312.8	319.3	632.1
	SO_2	1,435.5	1,598.0	3,033.5
	VOC	21.4	22.4	43.8
	PM	8.8	36.3	45.1
	PM_{10}	8.6	27.0	35.7
	SAM [a]	--	--	464.5
	CO_2	2,042,470.2	2,253,247.0	4,295,717.2

Source: Annual Operating Report (AOR) for JEA SJRPP, 2006 - 2010.

Table 3. Actual Emissions as a Function of Heat Input, 2006 - 2010

BOILER 1

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Boiler 1 Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2010	17,036,926	704.0	502.5	21.2	1,584.2	21.7	27.4	242.6	2,090,362.3	0.0826	0.0590	0.0025	0.1860	0.0025	0.0032	0.0285	245.4
2009	15,715,889	810.0	119.9	19.6	1,397.1	18.7	17.5	213.9	1,922,135.5	0.1031	0.0153	0.0025	0.1778	0.0024	0.0022	0.0272	244.6
2008	19,566,700	818.7	203.4	24.6	1,565.0	26.4	18.9	239.6	2,278,188.9	0.0837	0.0208	0.0025	0.1600	0.0027	0.0019	0.0245	232.9
2007	19,885,146	724.6	256.8	24.7	1,510.5	10.3	10.1	231.3	2,295,968.3	0.0729	0.0258	0.0025	0.1519	0.0010	0.0010	0.0233	230.9
2006	17,428,971	710.0	312.8	21.4	1,435.5	8.8	8.6	219.8	2,042,470.2	0.0815	0.0359	0.0025	0.1647	0.0010	0.0010	0.0252	234.4
									Maximum =	0.1031	0.0590	0.0025	0.1860	0.0027	0.0032	0.0285	245.4

BOILER 2

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Boiler 2 Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2010	18,408,883	902.7	200.3	22.1	1,607.5	16.2	20.4	246.1	2,125,872.5	0.0981	0.0218	0.0024	0.1746	0.0018	0.0022	0.0267	231.0
2009	16,098,710	804.1	150.5	20.0	1,387.9	29.0	27.0	212.5	1,948,776.2	0.0999	0.0187	0.0025	0.1724	0.0036	0.0034	0.0264	242.1
2008	16,891,904	701.2	125.0	21.2	1,565.0	33.5	22.9	239.6	1,828,111.5	0.0830	0.0148	0.0025	0.1853	0.0040	0.0027	0.0284	216.4
2007	18,985,228	719.3	329.5	23.0	1,411.7	37.6	28.0	216.2	2,100,239.5	0.0758	0.0347	0.0024	0.1487	0.0040	0.0029	0.0228	221.2
2006	18,305,895	782.0	319.3	22.4	1,598.0	36.3	27.0	244.7	2,253,247.0	0.0854	0.0349	0.0024	0.1746	0.0040	0.0030	0.0267	246.2
									Maximum =	0.0999	0.0349	0.0025	0.1853	0.0040	0.0034	0.0284	246.2

BOILERS 1 & 2

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Units 4 & 5 Total Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2010	35,445,809	1,606.7	702.8	43.3	3,191.7	38.0	47.8	488.7	4,216,234.8	0.0907	0.0397	0.0024	0.1801	0.0021	0.0027	0.0276	237.9
2009	31,814,599	1,614.1	270.4	39.6	2,785.0	47.7	44.5	426.5	3,870,911.7	0.1015	0.0170	0.0025	0.1751	0.0030	0.0028	0.0268	243.3
2008	36,458,604	1,519.9	328.4	45.9	3,130.0	59.8	41.8	479.3	4,106,300.4	0.0834	0.0180	0.0025	0.1717	0.0033	0.0023	0.0263	225.3
2007	38,870,374	1,443.9	586.3	47.8	2,922.2	47.9	38.1	447.5	4,396,207.8	0.0743	0.0302	0.0025	0.1504	0.0025	0.0020	0.0230	226.2
2006	35,734,866	1,492.0	632.1	43.8	3,033.5	45.1	35.7	464.5	4,295,717.2	0.0835	0.0354	0.0025	0.1698	0.0025	0.0020	0.0260	240.4
									Maximum =	0.1015	0.0397	0.0025	0.1801	0.0033	0.0028	0.0276	243.3

[a] Based on AOR data; see Table 1.

[b] Based on AOR data; see Table 2.

[c] Total actual emissions divided by total heat input.

Table 4. Estimated Actual Annual Emissions of N_2O and CH_4 for the Period 2006 - 2010
NGS Boiler Nos. 1 and 2

Unit	Actual Annual Heat Input [a] (MMBtu/yr)	N_2O Emissions: Emission Factor [b] (lb/MMBtu)	N_2O Annual Emissions (lb/yr)	N_2O Annual Emissions (TPY)	N_2O CO_2e [c] Rate (TPY)	CH_4 Emissions: Emission Factor [b] (lb/MMBtu)	CH_4 Annual Emissions (lb/yr)	CH_4 Annual Emissions (TPY)	CH_4 CO_2e [c] Rate (TPY)
Bituminous Coal									
2010	3,367,232	3.53E-03	11,874.2	5.9	1,840.5	2.4E-02	81,635.2	40.8	857.2
2009	2,848,199	3.53E-03	10,043.9	5.0	1,556.8	2.4E-02	69,051.7	34.5	725.0
2008	3,186,266	3.53E-03	11,236.0	5.6	1,741.6	2.4E-02	77,247.8	38.6	811.1
2007	5,711,622	3.53E-03	20,141.5	10.1	3,121.9	2.4E-02	138,472.6	69.2	1,454.0
2006	6,065,583	3.53E-03	21,389.7	10.7	3,315.4	2.4E-02	147,054.0	73.5	1,544.1
Natural Gas-Firing									
2010	59,024	2.20E-04	13.0	0.007	2.0	2.2E-03	130.1	0.065	1.4
2009	50,268	2.20E-04	11.1	0.006	1.7	2.2E-03	110.8	0.055	1.2
2008	116,483	2.20E-04	25.7	0.013	4.0	2.2E-03	256.7	0.128	2.7
2007	148,436	2.20E-04	32.7	0.016	5.1	2.2E-03	327.2	0.164	3.4
2006	103,635	2.20E-04	22.8	0.011	3.5	2.2E-03	228.4	0.114	2.4
Coke									
2010	32,019,553	3.53E-03	112,913.8	56.5	17,501.6	2.4E-02	776,282.0	388.1	8,151.0
2009	28,916,132	3.53E-03	101,969.8	51.0	15,805.3	2.4E-02	701,042.7	350.5	7,360.9
2008	33,155,855	3.53E-03	116,920.8	58.5	18,122.7	2.4E-02	803,830.6	401.9	8,440.2
2007	33,010,316	3.53E-03	116,407.6	58.2	18,043.2	2.4E-02	800,302.1	400.2	8,403.2
2006	29,565,648	3.53E-03	104,260.3	52.1	16,160.3	2.4E-02	716,789.6	358.4	7,526.3
Total									
2010	--	--	--	62.4	19,344.1	--	--	429.0	9,009.5
2009	--	--	--	56.0	17,363.8	--	--	385.1	8,087.2
2008	--	--	--	64.1	19,868.3	--	--	440.7	9,254.0
2007	--	--	--	68.3	21,170.2	--	--	469.6	9,860.6
2006	--	--	--	62.8	19,479.3	--	--	432.0	9,072.8

[a] Based on AOR data; see Table 1.
[b] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu were converted to lb/MMBtu by multiplying by 2.204.
[c] N_2O and CH_4 are multiplied by a factor of 310 and 21, respectively, to determine CO_2 equivalence.

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Table 5. Current Actual Pollution Control Efficiency

Pollutant	Uncontrolled Emission Factor [a] (lb/ton)	Fuel Heat Content [b] (MMBtu/ton)	Uncontrolled Emission Factor (lb/MMBtu)	Current Actual Emission Factors [c] (lb/MMBtu)	Actual Control Efficiency (%)
NO_x	5	26	0.192	0.1015	47.2
CO	18	26	0.692	0.04	94.3
SO_2	--	26	--	0.18	70.0 [d]
VOC	0.06	26	0.0023	0.0025	None
PM	13.2	26	0.508	0.0033	99.4
PM_{10}	13.2	26	0.508	0.0028	99.4
$PM_{2.5}$	13.2	26	0.508	0.0028	99.4

[a] Based on Tables 1.1-3, 1.1-4, 1.1-19 of Section 1.1, AP-42.
[b] Based on heat content of bituminous coal, 25 MMBtu/ton.
[c] Based on maximum current actual emission rates in lb/MMBtu for Boilers 1 and 2.
[d] Based on Table 1.1-1 of AP-42, typical control efficiency for spray drying 70 to 90%.

Table 6. Annual Average Emissions for Boilers 1 & 2 for Each Consecutive Two-Year Period, 2006-2010

	Annual Emissions for Boiler Nos. 1 & 2					Two-Year Average Emissions			
Pollutant	2010	2009	2008	2007	2006	2010-2009 (tons)	2009-2008 (tons)	2008-2007 (tons)	2007-2006 (tons)
NO_x	1,606.7	1,614.1	1,519.9	1,443.9	1,492.0	1,610.4	1,567.0	1,481.9	1,468.0
CO	502.5	270.4	328.4	586.3	632.1	386.5	299.4	457.3	609.2
SO_2	3,191.7	2,785.0	3,130.0	2,922.2	3,033.5	2,988.4	2,957.5	3,026.1	2,977.8
VOC	43.3	39.6	45.9	47.8	43.8	41.4	42.7	46.8	45.8
PM	38.0	47.7	59.8	47.9	45.1	42.8	53.8	53.8	46.5
PM_{10}	47.8	44.5	41.8	38.1	35.7	46.2	43.2	40.0	36.9
$PM_{2.5}$ [a]	47.8	44.5	41.8	38.1	35.7	46.2	43.2	40.0	36.9
SAM [b]	488.7	426.5	479.3	447.5	464.5	457.6	452.9	463.4	456.0
CO_2	4,216,234.8	3,870,911.7	4,106,300.4	4,396,207.8	4,295,717.2	4,043,573.3	3,988,606.0	4,251,254.1	4,345,962.5
N_2O [c] (CO_2e)	19,344.1	17,363.8	19,868.3	21,170.2	19,479.3	18,354.0	18,616.1	20,519.2	20,324.7
CH_4 [c] (CO_2e)	9,009.5	8,087.2	9,254.0	9,860.6	9,072.8	8,548.3	8,670.6	9,557.3	9,466.7

[a] Assuming equal to PM_{10} emissions.

[b] Not reported in AORs - based on assuming 10% of SO_2 converts to SO_3, all of which converts to SAM.

[c] Calculated based on actual annual heat input - see Table 3.

Source: Annual Operating Report (AOR) for 2006 - 2010; EPA's Acid Rain database.

Table 7. Projected Actual Emissions for NGS Boiler Nos. 1 and 2 due to Wood Chip Firing

Pollutant	Proposed Biomass Usage [a] (tons/day)	Biomass Heating Value [b] (Btu/lb)	Daily Heat Input from Biomass (MMBtu/day)	Annual Heat Input from Biomass [c] (MMBtu/yr)	Emission Factor [d] (lb/MMBtu)	Uncontrolled Annual Emissions (TPY)	Estimated Control Efficiency [e] (%)	Annual Emissions (TPY)
NO_x	600.0	8,000.0	9,600.0	3,504,000	0.22	385.4	47.2	203.4
CO	600.0	8,000.0	9,600.0	3,504,000	0.60	1,051.2	94.3	60.2
SO_2	600.0	8,000.0	9,600.0	3,504,000	0.025	43.8	70.0	13.1
VOC	600.0	8,000.0	9,600.0	3,504,000	0.017	29.8	0.0	29.8
PM	600.0	8,000.0	9,600.0	3,504,000	0.117	205.0	99.4	1.3
PM_{10}	600.0	8,000.0	9,600.0	3,504,000	0.091	159.4	99.4	1.0
$PM_{2.5}$	600.0	8,000.0	9,600.0	3,504,000	0.082	143.7	99.4	0.9
SAM	600.0	8,000.0	9,600.0	3,504,000	0.0038	6.7	70.0	2.0
GHGs [f]								
CO_2	600.0	8,000.0	9,600.0	3,504,000	206.7	362,200.1	0.0	362,200.1
N_2O	600.0	8,000.0	9,600.0	3,504,000	9.26E-03	16.2	0.0	16.2
CH_4	600.0	8,000.0	9,600.0	3,504,000	7.05E-02	123.6	0.0	123.6

[a] Proposed daily wood chip usage.
[b] Heating value based on Section 1.6 of AP-42. Dry wood heating value of 8,000 Btu/lb used as a conservative (high) value.
[c] Based on 365 days per year operation.
[d] Tables 1.6-1, 1.6-2, and 1.6-3, Section 1.6, AP-42. SAM emission factor based on assumption that 10% of the SO_2 is further oxidized to SO_3, which is then converted to SAM (98/80).
[e] Current actual control efficiency calculated in Table 5. Based on Table 1.1-1 of AP-42, typical SO_2 control efficiency for spray drying is 70 to 90%. SAM is also expected to be controlled at a similar efficiency as SO_2.
[f] GHG emission factors are based on Tables C-1 and C-2, Subpart 98, 40 CFR 60.

Table 8. PSD Applicability, Wood Chip Firing, NGS Boiler Nos. 1 and 2

Pollutant	Baseline Emissions[a] (TPY)	Baseline 2-Year Period	Maximum 2-Year Period Average Heat Input[a] (MMBtu/yr)	Current Actual Emission Factors (lb/MMBtu)	Heat Input to be Replaced by Wood Chips[b] (MMBtu/yr)	Current Actual Emissions for Heat Input Potential of Wood Chips[c] (TPY)	Wood Chip Firing Projected Actual Emissions [d] (TPY)	Increase/Decrease in Emissions (Projected – Current Actual) (TPY)	PSD Significant Emission Rates (TPY)
NO_x	1,610	2010 - 2009	33,083,086	0.1015	3,504,000.0	177.8	203.4	25.6	40
CO	609	2007 - 2006	37,302,620	0.04	3,504,000.0	69.5	60.2	-9.3	100
SO_2	3,026	2008 - 2007	37,664,489	0.18	3,504,000.0	315.5	13.1	-302.4	40
VOC	47	2008 - 2007	37,664,489	0.0025	3,504,000.0	4.4	29.8	25.4	40
PM	54	2008 - 2007	37,664,489	0.0033	3,504,000.0	5.7	1.3	-4.4	25
PM_{10}	46	2010 - 2009	33,083,086	0.0028	3,504,000.0	4.9	1.0	-3.9	15
$PM_{2.5}$	46	2010 - 2009	33,083,086	0.0028	3,504,000.0	4.9	0.9	-4.0	10
SAM[e]	463	2008 - 2007	37,664,489	0.0276	3,504,000.0	48.3	2.0	-46.3	7
GHGs									
CO_2	4,345,962	2007 - 2006	37,302,620	243.3	3,504,000.0	426,334.9	362,200.1		
N_2O (CO_2e)	20,519	2008 - 2007	37,664,489	1.1	3,504,000.0	1,908.9	5,027.6		
CH_4 (CO_2e)	9,557	2008 - 2007	37,664,489	0.5	3,504,000.0	889.1	2,594.9		
Total GHGs (CO_2e)	4,376,039.0					429,133.0	369,822.5	-59,310.5	75,000.0

[a] Based on AOR data for the period 2006 - 2010; see Table 6.
[b] See Table 2 for heat input potential for wood chips, which is the potential amount of current actual heat input to be replaced by wood chip burning.
[c] Current actual emissions for heat input potential of annual wood chip usage. This is the current actual annual emissions that will be replaced by emissions due to annual wood chip usage.
[d] Projected annual emissions for annual wood chip usage; see Table 7.
[e] SAM emissions data are not available (NA) in the AORs for 2005 - 2009.

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