Golder Associates Inc.

6026 NW 1st Place
Gainesville, FL 32607
Telephone (352) 336-5600
Fax (352) 336-6603

August 7, 2009 0838-7595

Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attention: Ms. Trina L. Vielhauer, Bureau of Air Regulation

RE: JACKSONVILLE ELECTRIC AUTHORITY
PERMIT NO. 0310045-020-AV
TITLE V REVISION APPLICATION
Project Nos.: 0310045-027-AC
0310045-028-AV

Dear Ms. Vielhauer:

On behalf of Jacksonville Electric Authority (JEA), please find attached four copies of a Title V revision application for the Northside Generating Station/St. Johns River Power Park and Separations Technology, LLC facility. Should you have any questions, feel free to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David Buff, P.E., Q.E.P.
Principal Engineer

RECEIVED
AUG 10 2009
BUREAU OF AIR REGULATION

Enclosures

DB/ng

cc: B. Gianaza
City of Jacksonville

L080709-595

TITLE V AIR OPERATION PERMIT REVISION APPLICATION

NORTHSIDE GENERATING STATION/
ST. JOHNS RIVER POWER PARK AND
SEPARATIONS TECHNOLOGY FACILITY
JACKSONVILLE ELECTRIC AUTHORITY

Prepared For:

JEA
21 West Church Street
Jacksonville, Florida 32202

Prepared By:

Golder Associates Inc.
6026 NW 1st Place
Gainesville, Florida 32607

August 2009

0838-7595

DISTRIBUTION:
4 Copies – FDEP
2 Copies – JEA
1 Copy – Golder Associates Inc.

APPLICATION FOR AIR PERMIT

LONG FORM

Department of Environmental Protection

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.

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To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Jacksonville Electric Authority (JEA)**	
2. Site Name: **Northside Generating Station/St. Johns River Power Park/Separations Technology, LLC**	
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. Application Contact Name: **N. Bert Gianazza, P.E.**
2. Application Contact Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **32202**
3. Application Contact Telephone Numbers... Telephone: **(904) 665-6247** ext. Fax: **(904) 665-7376**
4. Application Contact E-mail Address: **GianNB@jea.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 8-10-09	3. PSD Number (if applicable):
2. Project Number(s): 0310045-027-AC 0310045-028-AV	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 to revise Title V operating permit No. 0310045-020-AV to incorporate the specific conditions of air construction permit Nos. 0310045-017-AC, 0310045-022-AC, 0310045-024-AC, and 0310045-025-AC. The permits allowed the following changes:

- **The ability to operate CFB Boiler Nos. 1 and 2 (EU Nos. 027 and 026) with the Spray Dryer Absorber (SDA) offline due to malfunction or maintenance/repair.**
- **Installation and operation of natural gas igniters for startup, shutdown, low load operation and flame stabilization on SJRPP Boiler Nos. 1 and 2 (EU IDs 016 and 017) as well as the installation of selective catalytic reduction (SCR) to reduce nitrogen oxide emissions. The revised test method for sulfuric acid mist is Method 8A.**

This application is also being submitted to allow landfill gas to be burned in CFB Boiler Nos. 1 and 2 (EU Nos. 027 and 026). Additionally, it is being requested that Table 6C be removed from the permit and revised Table 6 - Part B with the materials handling for SJRPP be incorporated.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
016	SJRPP: Boiler No. 1		N/A
017	SJRPP: Boiler No. 2		N/A
026	NGS: Circulating Fluidized Bed Boiler No. 2		N/A
027	NGS: Circulating Fluidized Bed Boiler No. 1		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:
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Owner/Authorized Representative Telephone Numbers... Telephone: ( ) ext. Fax: ( )
4. Owner/Authorized Representative E-mail Address:
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.* _____ _____ Signature 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:
   James M. Chansler, P.E, D.P.A., Chief Operating Officer

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, CAIR source, or Hg Budget source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: **JEA**
   Street Address: **21 West Church Street**
   City: **Jacksonville** State: **FL** Zip Code: **32202**

4. Application Responsible Official Telephone Numbers...
   Telephone: **(904) 665-4433** ext. Fax: **(904) 665-7990**

5. Application Responsible Official E-mail Address: **chanjm@jea.com**

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.

James M. Chansler — 7/31/09

Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
   Registration Number: **19011**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6241 NW 1st Place**
   City: **Gainesville** State: **FL** Zip Code: **32607**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext. **21145** Fax: **(352) 336-6603**
4. Professional Engineer E-mail Address: **dbuff@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.

David A. Buff
Signature

8/7/09
Date

(seal)

* 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 JEA Northside Generating Station, SJRPP, and Separation Technologies' fly ash beneficiation process.**			

Facility Contact

1. Facility Contact Name: **N. Bert Gianazza, P.E.**		
2. Application Contact Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **32202**		
3. Application Contact Telephone Numbers... Telephone: **(904) 665-6247** ext. Fax: **(904) 665-7376**		
4. Application 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 CFB Units 1 and 2, and SJRPP Units 1 and 2 are subject to 40 CFR Part 60 Subpart Da.	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	A	Y (for NGS)
PM10	A	N
NOx	A	Y (for NGS)
CO	A	N
VOC	A	N
SO2	A	Y (for NGS)
PB	B	N
Mercury (H114)	B	N
SAM	B	N
HF (H107)	A	N
HCl (H106)	A	N
Formaldehyde (H095)	A	N
Hexane (H104)	A	N
Manganese compounds (H113)	A	N
Nickel compounds (H133)	A	N
HAPs	A	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
NOx	N	NGS Units 1, 2, and 3		3,600	0310045-022-AC/PSD-FL-265E
PM	N	NGS Units 1, 2, and 3		881	0310045-022-AC/PSD-FL-265E
SO2	N	NGS Units 1, 2, and 3		12,284	0310045-022-AC/PSD-FL-265E

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: **Attachment A**

3. Rule Applicability Analysis:
   ☒ Attached, Document ID: **Attachment A**

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: JEA-FI-CV3
   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: See EUs and Attachment A ☐ 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)

3. Hg Budget Part (DEP Form No. 62-210.900(1)(c)):
   ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____
   ☒ Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

ATTACHMENT JEA-FI-CV3

COMPLIANCE REPORT

ATTACHMENT JEA-FI-CV3a

COMPLIANCE REPORT

Jacksonville Electric Authority (JEA) certifies that the Northside Generating Unit (NGS), and the contiguous St. Johns River Power Park (SJRPP), as of the date of this application, are in compliance with each applicable requirement addressed in this Title V air permit revision application, except for those applicable requirements identified in the attached compliance plan.

I, the undersigned, am the responsible official as designed in Chapter 62-213, F.A.C., of the Title V source for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate, and complete.

Compliance statements for this facility will be submitted on an annual basis to FDEP, on or before March 1 of each year.

James M. Chansler 7/31/09

Signature, Responsible Official Date

ATTACHMENT JEA-FI-CV3b

COMPLIANCE PLAN FOR
JACKSONVILLE ELECTRIC AUTHORITY

CFB BOILER NOS. 1 AND 2 – SDA ENGINEERING STUDY

Deviations from Applicable Requirements

Air Construction Permit No. 0310045-022-AC was issued on February 6, 2009, allowing CFB Boiler Nos. 1 and 2 to take off-line the spray dryer absorber for maintenance and/or repair while keeping the circulating fluidized bed boiler operational with additional injection of limestone to the boilers. Condition No. 49 of this permit requires an engineering study detailing opportunities to increase the reliability and availability of the SDA system. The report must be provided no later than December 31, 2010.

Compliance Plan

JEA will complete and submit the engineering study regarding reliability and availability of the SDA system prior to the December 31, 2010 deadline.

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.

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

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:
SJRPP - Boiler No. 1 and 2.

3. Emissions Unit Identification Number: **016 and 017**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**12/86**	**49**

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

☒ Acid Rain Unit

☒ CAIR Unit

☐ Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **679.6** MW

11. Emissions Unit Comment:
Initial Startup Date for Unit 1 is the commercial operation date. Unit 2 began commercial operation in March 1988. Generator Nameplate Rating is nominal and for each unit.

Emissions Unit Control Equipment/Method: Control 1 of 4

1. Control Equipment/Method Description: **Electrostatic Precipitators (ESP) for PM control.**
2. Control Device or Method Code: **010**

Emissions Unit Control Equipment/Method: Control 2 of 4

1. Control Equipment/Method Description: **Flue Gas Desulfurization (FGD) for SO_2 control.**
2. Control Device or Method Code: **039**

Emissions Unit Control Equipment/Method: Control 3 of 4

1. Control Equipment/Method Description: **Low NO_x Burners and overfire air for NO_x control.**
2. Control Device or Method Code: **204 and 205**

Emissions Unit Control Equipment/Method: Control 4 of 4

1. Control Equipment/Method Description: **Selective Catalytic Reduction (SCR) with ammonia injection for NO_x control.**
2. Control Device or Method Code: **139 and 032**

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: **12,288** 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 rate for each unit is 6,144 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: **EU016 and EU017**		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: **SJRPP - Boiler No. 1 (EU16) shares a common stack with SJRPP - Boiler No. 2 (EU17). The common stack contains two separate flues, one for each boiler.**		
5. Discharge Type Code: **V**	6. Stack Height: **640** feet	7. Exit Diameter: **22.3** Feet
8. Exit Temperature: **156**°F	9. Actual Volumetric Flow Rate: **1,800,000** 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: **Source: Title V Renewal Application Submitted July 3, 2008. Stack parameters are for each boiler. Each boiler exhausts through its own flue but through a common stack.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 4

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: **147.5**	5. Maximum Annual Rate: **1,314,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash: **18**	9. Million Btu per SCC Unit: **26**
10. Segment Comment: **Based on firing a coal blend with a maximum 30% pet coke by weight. Maximum rates total both units. Maximum annual rate based on 150,000 lb/hr pet coke per unit, 30-day rolling average. (Permit No. 0310045-020-AV.)**		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom**		
2. Source Classification Code (SCC): **1-01-002-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **491.52**	5. Maximum Annual Rate: **4,305,715**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **4**	8. Maximum % Ash: **18**	9. Million Btu per SCC Unit: **25**
10. Segment Comment: **Maximum rates are total for both units.**		

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

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Natural-Gas Boilers >100 MMBtu/hr**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.37**	5. Maximum Annual Rate: **12,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,022**
10. Segment Comment: **Each unit: Maximum hourly rate = 700 MMBtu/hr /1022 MMBtu/10^6 ft^3 = 0.685 x 10^6 ft^3/hr Maximum annual rate = 0.685 10^6 ft^3/hr x 8,760 hr/yr = 6,000 x 10^6 ft^3 Each unit: Maximum hourly rate of 700 MMBtu/hr based on 28 igniters each rated at 25 MMBtu/hr. (Note: Natural gas used for startup, shutdown, flame stabilization and low-load operation). Based on permit No. 0310045-024-AC.**		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Distillate Oil - Grades 1 or 2 oil**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **1,000 Gallons burned**	
4. Maximum Hourly Rate: **14.2**	5. Maximum Annual Rate: **124,417**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.76**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Can include "on-specification" used oil. Each unit: Maximum hourly rate = 980 MMBtu/hr /138 MMBtu/1,000 gallon = 7.1x10^3 gallons/hr. Maximum annual rate = 7.1x10^3 gallons/hr x 8,760 hr/yr = 62,196 x 10^3 gallons/yr. Each unit: Maximum hourly rate of 980 MMBtu/hr based on 28 igniters each rated at 35 MMBtu/hr. No. 2 fuel oil used for startup, shutdown, flame stabilization and low-load operation). Based on permit No. 0310045-024-AC.**		

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	204 and 205	139 and 032	EL
CO			NS
SO2	039		EL
VOC			NS
PM	010		EL
PM10	010		NS
SAM	032		NS
PB	010		NS
NH3			EL
Acetaldehyde (H001)			NS
Benzene (H017)			NS
Benzyl chloride (H020)			NS
Cyanide Compounds (H054)			NS
HCl (H106)			NS
HF (H107)			NS
Isophorone (H109)			NS
Manganese Compounds (H113)			NS
Methyl chloride (H118)			NS
Selenium Compounds (H162)			NS
HAPs			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: **7,372.8** lb/hour **24,757.9** 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, 30-day rolling average** **0.46 lb/MMBtu, calendar year average** Reference: **Permit No. 0310045-020-AV**	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: Hourly NOx emissions rate: 0.6 lb/MMBtu x 6,144 MMBtu/hr = 3,686.4 lb/hr
Each unit: Annual NOx emissions rate:
0.46 lb/MMBtu x 6,144 MMBtu/hr x 8,760 hr/yr x ton/2,000 lb = 12,378.9 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

0.6 lb/MMBtu on a 30-day rolling average when firing coal or a coal/petcoke blend.
0.46 lb/MMBtu on a calendar year average.
Emissions represent total for 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 1 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: **7,372.8** lb/hour **32,292** 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 a 30-day rolling average.** **Based on 40 CFR 60, Subpart Da.** **Applicable when firing coal and petroleum coke blends.** **Total 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: **0.3 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **3,686.4** lb/hour 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 a 30-day rolling average.** **Based on 40 CFR 60, Subpart Da.** **Applicable when firing fuel oil.** **Total 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: **See Comment**	4. Equivalent Allowable Emissions: lb/hour 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): **PSNOx= (130X+260Y)/100** **Where PSNOx=NOx emissions standard in ng/J** **X= % of total heat input derived from the combustion of fuel oil.** **Y= % of total heat input derived from the combustion of coal or a blend of coal and petroleum coke.** **Based on 40 CFR 60, Subpart Da.**	

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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.46 lb/MMBtu, calendar year average**	4. Equivalent Allowable Emissions: lb/hour **24,757.9** 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 a calendar year average.** **Based on 40 CFR 76.7(a)(2).** **Total 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: **14,746** lb/hour **40,904** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.20 lb/MMBtu (2-hr average basis)** **0.76 lb/MMBtu (30-day rolling average basis)** Reference: **Permit No. 0310045-020-AV**	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:

Coal only

Each unit: Hourly SO_2 emissions rate (2-hr average): 1.20 lb/MMBtu x 6,144 MMBtu/hr = 7,373 lb/hr

Each unit: Hourly SO_2 emissions rate (30-day average): 0.76 lb/MMBtu x 6,144 MMBtu/hr = 4,669 lb/hr

Each unit: Annual SO_2 emissions rate: 4,669 lb/hr x 8,760 hr/yr x ton/2000 lb = 20,452 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions represent total for 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 1 of 10

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.20 lb/MMBtu, 2-hr average**	4. Equivalent Allowable Emissions: **14,746** lb/hour 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. 0310045-020-AV** **Applicable when firing coal.** **Total both boilers.**	

Allowable Emissions Allowable Emissions 2 of 10

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.76 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **9,338** lb/hour **40,904** 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. 0310045-020-AV** **Applicable when firing coal.** **Total both boilers.**	

Allowable Emissions Allowable Emissions 3 of 10

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **70% reduction of potential combustion concentrations if emissions are less than 0.60 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour 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.** **Applicable when firing coal.**	

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 **10**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0% reduction of potential combustions concentrations if emissions are less than 0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour 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.** **Applicable when firing coal.**	

Allowable Emissions Allowable Emissions **5** of **10**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.676 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **8,306** lb/hour **36,384** 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. 0310045-020-AV** **Applicable when firing coal and petroleum coke blends.** **Total both boilers.**	

Allowable Emissions Allowable Emissions **6** of **10**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.53 lb/MMBtu**	4. Equivalent Allowable Emissions: **6,512** lb/hour **199,687** 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. 0310045-020-AV** **Applicable when firing coal and petroleum coke blends.** **Total for 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 7 of 10

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: lb/hour 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): **SO2 (lb/MMBtu)= (0.2 x C / 100) + 0.4** **Where C = percent of coal fired on a heat input basis (30-day rolling average)** **Permit No. 0310045-020-AV** **Applicable when firing coal and petroleum coke blends.**	

Allowable Emissions Allowable Emissions 8 of 10

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See comment**	4. Equivalent Allowable Emissions: lb/hour 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): **SO2 (lb/MMBtu)= (0.1653 x C x S - 0.4 x C + 40) x 1/100** **Where C = percent of coal co-fired on a heat input basis** **S = weight percent sulfur in coal (30-day rolling average)** **Permit No. 0310045-020-AV** **Applicable when firing coal and petroleum coke blends.**	

Allowable Emissions Allowable Emissions 9 of 10

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **2,458** lb/hour 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): **Applies when firing liquid fuels only.** **Permit No. 0310045-020-AV** **Total for 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 **10** of **10**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See comment**	4. Equivalent Allowable Emissions: lb/hour 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): **Prorated formulas specified in 40 CFR 60.43(h).** **Permit No. 0310045-020-AV.**	

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: **368.64** lb/hour **1,614** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **Permit No. 0310045-020-AV**	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: Hourly emissions: 0.03 lb/MMBtu x 6,144 MMBtu/hr = 184 lb/hr
Each unit: Annual emissions: 184 lb/hr x 8,760 hr/yr x ton/2000 lb = 806 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Emissions represent total for 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 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **368.64** lb/hour **1,614** tons/year
5. Method of Compliance: **EPA Method 5B; 40 CFR 52.21(b)21(v) and (33)**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-017-AC Total 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: lb/hour **1,323** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Permit 0310045-017-AC**	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:	
11. Potential, Fugitive, and Actual Emissions Comment: **Permit No. 0310045-017-AC considered that the actual annual emissions due to the SCR would not exceed the SAM annual emissions (1,317 + 6 = 1,323 tons/yr). SAM included to document revised compliance method: EPA Method CTM-013 (Method 8A).**	

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:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **EPA Method CTM-013 (Method 8A)**	
6. Allowable Emissions Comment (Description of Operating Method): **DEP Order No. 09-I-AP, issued 6/22/09**	

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: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COMS**	
5. Visible Emissions Comment: **40 CFR 60.42a(b)**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **COMS**	
5. Visible Emissions Comment: **Excess emissions resulting from startup, shutdown, and malfunction for no more than 2 hours in any 24 hour period. Rule 62-210.700(1)**	

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 4

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: **See comment**	6. Performance Specification Test Date: **See comment**
7. Continuous Monitor Comment: **Serial Number: SJRPP Boiler No. 1: 0295772** **Serial Number: SJRPP Boiler No. 2: 0295748** **Installation Date: SJRPP Boiler No. 1: March 2007** **Installation Date: SJRPP Boiler No. 2: May 2007** **Test Date: SJRPP Boiler No. 1: March 2007** **Test Date: SJRPP Boiler No. 2: June 2007**	

Continuous Monitoring System: Continuous Monitor 2 of 4

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: **See comment**	6. Performance Specification Test Date: **See comment**
7. Continuous Monitor Comment: **Serial Number: SJRPP Boiler No. 1: 0610416572** **Serial Number: SJRPP Boiler No. 2: 0631019327** **Installation Date: SJRPP Boiler No. 1: March 2007** **Installation Date: SJRPP Boiler No. 2: May 2007** **Test Date: SJRPP Boiler No. 1: March 2007** **Test Date: SJRPP Boiler No. 2: June 2007**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor 3 of 4

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **410i**	Serial Number:
5. Installation Date: **See comment**	6. Performance Specification Test Date: **See comment**
7. Continuous Monitor Comment: **Serial Number: SJRPP Boiler No. 1: 0633419623** **Serial Number: SJRPP Boiler No. 2: 0618617300** **Installation Date: SJRPP Boiler No. 1: March 2007** **Installation Date: SJRPP Boiler No. 2: May 2007** **Test Date: SJRPP Boiler No. 1: March 2007** **Test Date: SJRPP Boiler No. 2: June 2007**	

Continuous Monitoring System: Continuous Monitor 4 of 4

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information.... Manufacturer: **LAND** Model Number: **4500MKII++**	Serial Number: **See comment**
5. Installation Date: **September 21, 2002**	6. Performance Specification Test Date: **October 23, 2002**
7. Continuous Monitor Comment: **Serial Number: SJRPP Boiler No. 1: 0295772** **Serial Number: SJRPP Boiler No. 2: 0295748**	

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 **07/03/2008**

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: **JEA-EU1-I3** ☐ Previously Submitted, Date _____

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 **07/03/2008**
   ☐ 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 **07/03/2008**
   ☐ 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): **August 17,2009**
   Test Date(s)/Pollutant(s) Tested: **June 22-26, 2009 / SAM, NH3**
   ☐ 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

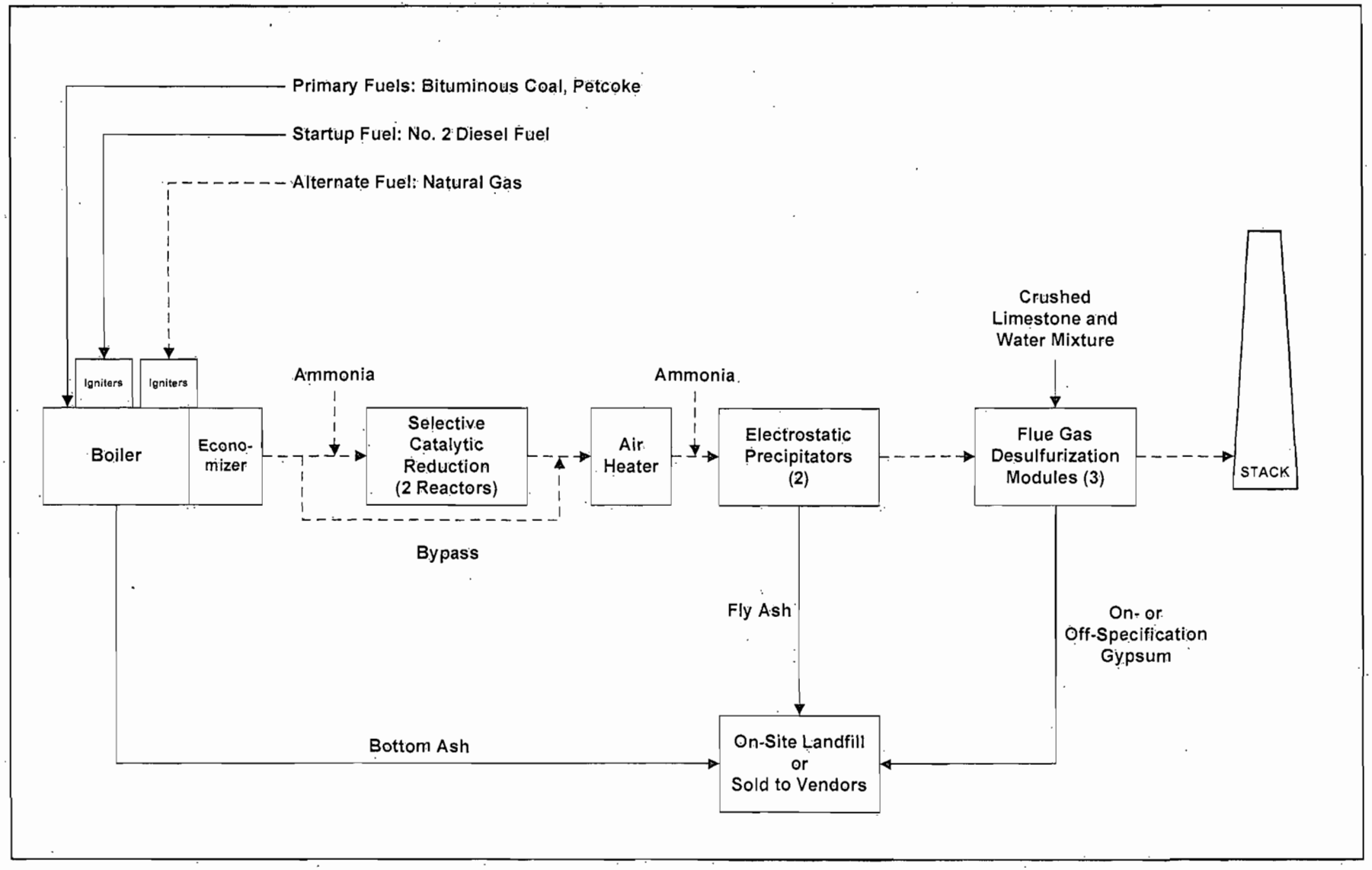
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☒ Attached, Document ID: JEA-EU1-IV1
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation: ☒ Attached, Document ID: JEA-EU1-IV3 ☐ 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
SJRPP Boiler Nos. 1 and 2 (EU 016 and 017)

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: JEA-EU1-I1.vsd
Date: 08/07/09

Golder Associates

ATTACHMENT JEA-EU1-I3a

DETAILED DESCRIPTION OF CONTROL EQUIPMENT
SELECTIVE CATALYTIC REDUCTION SYSTEM (SCR)
SPECIFICATIONS

ATTACHMENT JEA-EU1-I3a

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

SELECTIVE CATALYTIC REDUCTION

JACKSONVILLE ELECTRIC AUTHORITY, JACKSONVILLE, FLORIDA

Control equipment: Selective catalytic reduction.

Parameter	Operating Range*
Baseline NO_x Loading	0.4 lb/MMBtu
Target NO_x Emissions	0.06 lb/MMBtu
Ammonia Slip	2 ppmvd at 3% O_2
SO_2 to SO_3 Conversion	2.5%
Catalyst Type	High Dust
Catalyst Configuration	Vertical
Number or Reactor Per Unit	2
Number of Initial Catalyst Layers (per Reactor)	3
Number of Spare Layers (per Reactor)	1
Modules Per Layer (per Reactor)	14 x 6
Reactor Dimensions (Inside x Inside)	46' 10" x 40' 3"
Full Load Gas Flow	3,292,190 acfm
Superficial Velocity Through Catalyst	15 to 20 ft/sec
Pressure Drop Through Box and Ductwork	10.0 inches (w.c.)
Ammonia Consumption at Design Conditions	839 lb/hr
Reagent Storage Required	2 x 77,100 gallons

ATTACHMENT JEA-EU1-I3b

DETAILED DESCRIPTION OF CONTROL EQUIPMENT
SCR SYSTEM DESCRIPTION

(FROM 2008 TITLE V REVISION AND RENEWAL APPLICATION)

ST. JOHNS RIVER POWER PARK
NO_x REDUCTION PROJECT

SYSTEM DESCRIPTION FOR
SELECTIVE CATALYTIC REDUCTION SYSTEM

Adapted from Title V Operation Permit Revision and Renewal Application

Black & Veatch Corporation, July 2008

1.0 SYSTEM DESCRIPTION

1.1 Function

The purpose of the Selective Catalytic Reduction (SCR) System is to reduce the nitrogen oxide (NO_x) emissions exiting the stack. This system is designed for operation over load ranges of 50 percent of full load [approximately 300 megawatts (MW), net] and higher. The minimum temperature required for ammonia (NH_3) injection to react with the NO_x in the SCR reactor is 612 degrees Fahrenheit (°F), which corresponds to lowest expected temperature at low loads.

1.2 General Description

Selective catalytic reduction is a process that uses a catalyst to promote the conversion of NO_x to nitrogen (N_2) and water (H_2O) vapor in the flue gas. This conversion occurs between the boiler economizer and the air heaters in a specially designed ductwork section, called the SCR Reactor, which contains the catalyst. Ammonia vapor, mixed with dilution air, is injected into the flue gas upstream of the catalyst and is thoroughly mixed with the flue gas prior to its admittance to the catalyst. As the flue gas passes over the catalyst, the nitrogen monoxide (NO) and nitrogen dioxide (NO_2) combine with the NH_3 to form N_2 and H_2O.

2.0 COMPONENT DESCRIPTION

2.1 Description

The purpose of the catalyst is to promote the reaction between NO_x and NH_3 to form N_2 and H_2O at temperatures between 612°F and 800°F. This is the temperature range of the flue gas downstream of the economizer and upstream of the air heater.

The catalyst used for NO_x reduction service primarily consists of a vanadium, titanium, and tungsten mixture. However, the final catalyst composition can consist of many active metals and support materials. Titanium dioxide (TiO_2) is used as the base material that disperses and supports vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3), which are the active catalyst materials. Vanadium pentoxide is widely used in the SCR industry due to its resistance to sulfur poisoning. The vanadium content controls the reactivity of the catalyst, but also catalyzes the oxidation of sulfur dioxide (SO_2)

to sulfur trioxide (SO_3). For this moderate to high sulfur coal application, it is necessary to minimize the vanadium content to reduce SO_2 oxidation. Additionally, the vanadium already present in the petcoke fuel may deposit on the catalyst, increasing the oxidation of SO_2 to SO_3 over time. Tungsten trioxide also provides thermal and mechanical stability to the catalyst. The concentrations of V_2O_5, TiO_2, and WO_3 are customized to meet the specific requirements for this SCR system installation. The catalyst is made up of numerous catalyst modules that are loaded into the SCR reactor.

The catalyst is selected to ensure adequate NO_x reduction and acceptable SO_2 oxidation. In addition, the catalyst is designed to withstand temperatures up to 880°F.

Testing of the catalyst will be performed if the performance results are not met and for the Catalyst Management Program. The program is used to monitor catalyst performance throughout the life of the catalyst in order to ensure the optimal catalyst design is used as plant operation could vary in the future. Each catalyst module has a removable catalyst test box, with an installed handle. There are a total of 84 catalyst test boxes per layer.

2.2 Design Conditions

The catalyst sizing is determined by the physical and chemical characteristics of the flue gas. For this project, a catalyst pitch of 8.2 millimeters (mm) is used, with a wall thickness of 1.0 mm. These two parameters work together to ensure a proper balance between percent open area (to reduce pressure losses) and mechanical strength required for catalyst handling and washing.

3.0 REACTOR AND DUCTWORK

3.1 Description

The purpose of the reactor and associated ductwork is to bring the flue gas into contact with the SCR catalyst in order to facilitate the chemical reactions from NO_x to N_2 and H_2O.

The ductwork for the SCR system consists of an inlet duct, an outlet duct, a bypass duct, the reactor housing, and the associated dampers and expansion joints as indicated on the SCR system arrangement drawings. The ammonia injection grid (AIG) penetrates one wall of the SCR reactor inlet duct and extends the entire width of the duct.

Each unit is provided with two SCR reactors (one per economizer outlet/air heater inlet path) with up to four layers of catalyst modules. The SCR system is located between the boiler economizer outlet and the air preheater inlet. The SCR system is upstream of the air preheaters, electrostatic precipitators (ESPs), induced draft (ID) fans, and scrubbers. The boiler flue gas exits the boiler economizer in two sections and is directed through the two SCR reactors using dampers. The flue gas passes through a static mixing device and through the AIG before entering the SCR catalyst field. Ammonia is injected into the flue gas at the AIG, at a ratio of 1.05 moles of NH_3 for every mole of NO_x being removed.

The flue gas then passes through the SCR catalyst, where the NH_3 reacts with the NO_x in the flue gas to form nitrogen and water vapor. The flue gas then exits the SCR reactors and enters the two existing air preheaters. The boiler flue gas then passes through the ESP, ID fans, and scrubbers and discharges into the atmosphere via the chimney.

For maintenance requirements, each SCR reactor may be bypassed by closing the reactor inlet diverter damper and closing the reactor outlet isolation dampers. During SCR reactor bypass operation, flue gas is directed from the boiler economizer outlet to the air preheater inlet. Additional maintenance dampers are provided at the SCR inlet and outlet for double isolation of the reactor while the boiler is in operation. This provides for zero leakage of flue gas into the SCR reactor during bypass operation.

The reactor is a vertical, downward flow design and is capable of holding a total of four catalyst layers. Only the upper three layers are initially loaded with catalyst. The fourth layer will be added later when the catalyst performance deteriorates to an unacceptable level, or if changes in fuel blends require additional catalyst activity. The catalyst modules are stacked in frames designed to support the full weight of the modules. Each layer is capable of holding catalyst that is up to 5.3 feet in height.

Each reactor layer is equipped with sonic horns to prevent ash from accumulating on the catalyst surface. If petcoke firing returns to the fuel mix, catalyst will be installed only on Layers 2 through 4, and soot blowers will be installed on those layers. Soot blowers will be located approximately 20 inches above the catalyst face, independent of the catalyst depth. Catalyst module frames are designed based on the actual catalyst module length, to maintain the soot blower dimension above the

catalyst face. Each reactor layer is also designed to facilitate the periodic removal and replacement of the catalyst modules.

NO_x monitoring equipment is located upstream of the AIG and at the outlet of the SCR reactor. Carbon monoxide (CO) and O_2 instrumentation is located on the ductwork at the economizer outlet. A sample grid is located downstream of the fourth catalyst layer (at the outlet of SCR reactor) for tuning the AIG. A differential pressure transmitter is installed across the catalyst layers to monitor any change in differential pressure due to catalyst plugging. Test ports are located on the ductwork in the following locations:

- Between the economizer outlet and the inlet diverter damper (upstream of the LPA screen)
- After the inlet maintenance damper (upstream of the static mixer)
- After the AIG upstream of the SCR reactor
- On the SCR reactor before and after each catalyst layer
- Between the SCR reactor outlet and the air preheater inlet

Ductwork, plate, and stiffeners are constructed of ASTM A588 steel material. Turning vanes and flow straightening devices located in the ductwork consist of ASTM A588 steel material. The ductwork is designed to minimize the need for internal trusses wherever possible. Turning vanes and flow straightening devices are provided as indicated by flow modeling studies performed by the catalyst supplier during the detailed design. Expansion joints are located in the ductwork as required to accommodate thermal movement of the ductwork.

3.2 Design Conditions

The SCR reactors are sized to provide a flue gas velocity of 16.4 to 19.6 feet per second (fps) at the catalyst face. The velocity in the ductwork containing the static mixer, AIG, and the SCR outlet isolation louver damper is approximately 50 fps. The velocity in the remaining ductwork is between 45 and 60 fps.

The design pressure and temperature of the SCR inlet duct, reactor, and outlet duct is ±35 inches wg and 800°F, respectively.

4.0 AMMONIA INJECTION GRID

4.1 Description

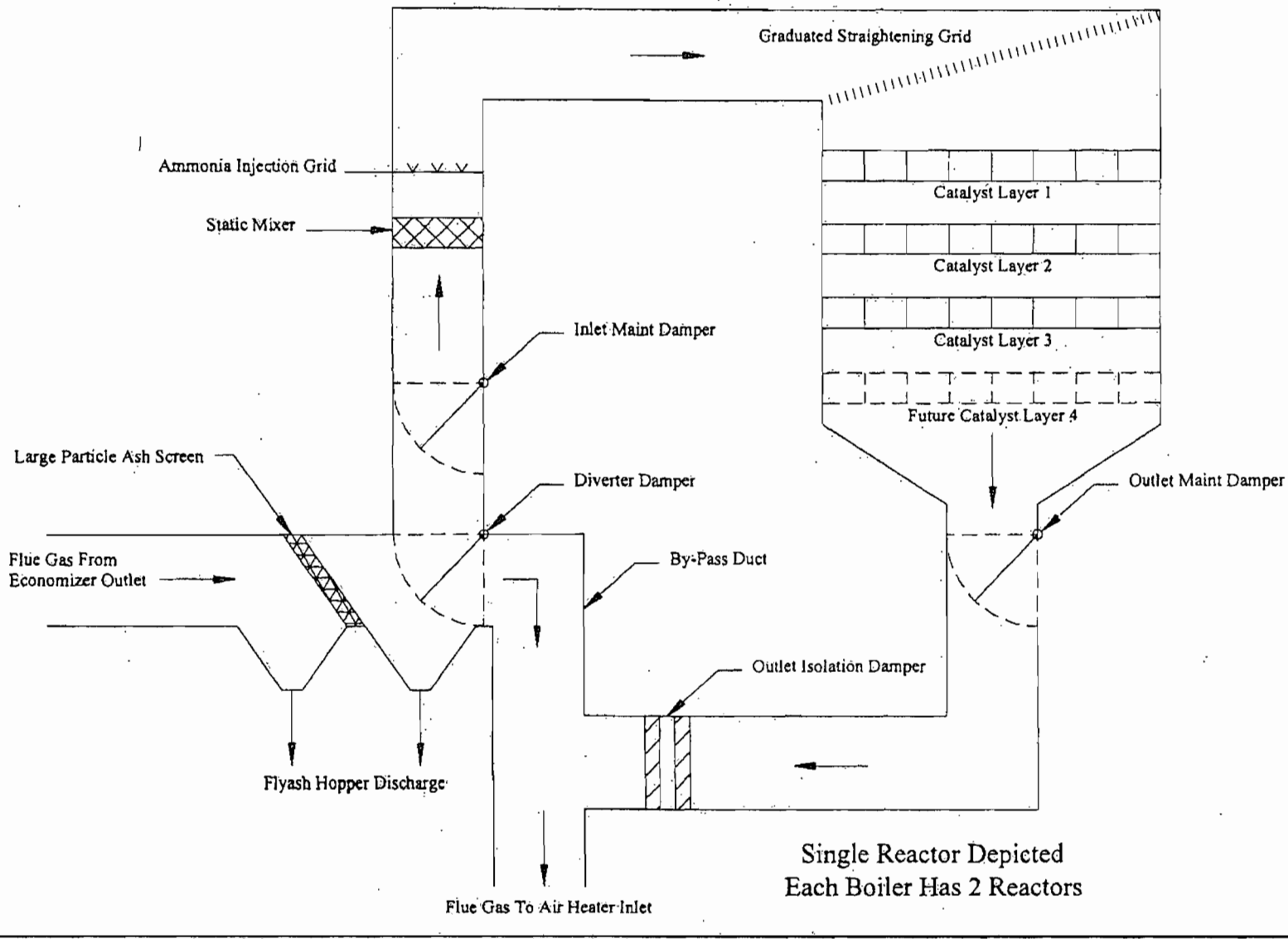
The function of the AIG is to introduce NH_3 into the flue gas before it enters the SCR reactor.

An air/NH_3 vapor mixture flows from the NH_3 vaporization equipment into the AIG distribution header, where it is introduced into the SCR reactor inlet duct and distributed across the entire duct cross section via the AIG. The AIG consists of a series of stacked layers of parallel pipes, each with nozzles that inject the mixture into a specific section of the SCR reactor inlet duct. The pipes extend the entire width of the ductwork and contain a sufficient number of nozzles sized for the particular NH_3 distribution requirement. The piping from the distribution header includes manual flow control valves, flow elements, and differential pressure indicators to adjust/tune the NH_3 injection flow.

The AIG distribution header, supply lines, and all components outside the flue gas stream are manufactured of carbon steel. The AIG located inside the flue gas stream is constructed of ASTM A335 P11 alloy steel.

During the initial SCR reactor startup phase, and approximately once a year thereafter, the flow rate of the air/NH_3 vapor through the nozzles is optimized by manually adjusting the NH_3 flow control valves in the AIG supply lines. This initial setting and periodic adjustment optimizes the distribution of the NH_3 across the SCR inlet duct cross-section to minimize both the NO_x emissions and ammonia slip. The flow elements consist of Type 316 stainless steel orifice plates installed between a pair of carbon steel orifice flanges. Differential pressure indicators measure the pressure drop across the flow orifice. The sample grid at the SCR Reactor outlet is used to collect NO_x readings, which provide indication for adjustment of the flow control valves.

The potential increase in sulfuric acid mist (SAM) emissions due to the SCR process will be minimized through the injection, downstream of the SCR, of NH_3 to react with the SO_3 prior to the ESP. The system is designed to remove 90 percent of the SAM after the air heater. The amount of NH_3 injected into the flue gas conditioning system will be regulated based on load and SO_2 content. The reactant, primarily ammonium sulfate, will be collected in the ESP and flue gas desulfurization (FGD) system. The ammonia slip after the ESP, from the SCR process, is expected to be 2 parts per million or less.



Attachment JEA-EU1-I3b Figure
SJRPP SCR System
08387595\TVRev\JEA-EU1-I3b Fig

Source: Black & Veatch, 2008.

Golder Associates

ATTACHMENT JEA-EU1-IV1a

IDENTIFICATION OF APPLICABLE REQUIREMENTS

PERMIT NO. 0310045-017-AC

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF PERMIT REVISION

In the Matter of an
Application for Permit Revision by:

JEA
21 West Church Street
Jacksonville, Florida 32202

Authorized Representative:
Mr. Michael J. Brost, Vice President – Electric System

Air Permit No. PSD-FL-010H
Project No. 0310045-024-AC
St. Johns River Power Park
Add Natural Gas Igniters on the Pulverized Coal and Petroleum Coke-Fired Boilers Nos. 1 and 2

JEA operates the existing St. Johns River Power Park located at 11201 New Berlin Road in Jacksonville, Duval County, Florida. The facility is an electric utility. This final air construction permit revision authorizes the installation and operation of natural gas igniters for startup, shutdown, low load operation and flame stabilization, on the pulverized coal and petroleum coke-fired Boilers Nos. 1 and 2. In addition, the applicant is also authorized to use the existing No. 2 distillate fuel oil igniters for flame stabilization and shutdown on Boilers Nos. 1 and 2 [the existing No. 2 distillate fuel oil igniters are already authorized to be used for startup and low load operation (PA81-13)]. The original air construction permit No. PSD-FL-010, required that the auxiliary boiler fire No. 2 fuel oil while providing startup and shutdown capability for Boilers Nos. 1 and 2. A copy of this Notice of Permit Revision shall be filed with the referenced permit and shall become part of the permit. This permit revision is issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

Joseph Kahn, Director
Division of Air Resource Management

11/21/08
(Date)

JK/tlv/sa/bm

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Permit Revision (including the Final Permit Revision) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on 11/24/08 to the persons listed below.

Mr. Michael J. Brost, JEA (brosmj@jea.com)
Mr. John A. Worley, JEA (worlja@jea.com)
Mr. Kennard F. Kosky, Golder Associates, Inc. (kkosky@golder.com)
Mr. Richard Robinson, Duval County Environmental Quality Division (robinson@coj.net)
Ms. Kathleen Forney, U.S. EPA, Region 4 (forney.kathleen@epamail.epa.gov)
Ms. Heather Abrams, U.S. EPA Region 4 (abrams.heather@epamail.epa.gov)
Ms. Catherine Collins, Fish and Wildlife Service (catherine_collins@fws.gov)
Mr. Mike Halpin, DEP-Siting Coordination Office (mike.halpin@dep.state.fl.us)
Ms. Vickie Gibson, DEP-BAR (victoria.gibson@dep.state.fl.us) (for read file)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 11/24/08 (Date)

This permit revision modifies original Permit No. PSD-FL-010.

For pulverized coal-fired Boilers Nos. 1 and 2, the following permit revision (new specific condition) incorporates the authorization to use No: 2 fuel oil for startup and low load operation from the original Power Plant Siting Permit No. PA81-13. The new specific condition also recognizes the requirement that No. 2 fuel oil be used during startup and shutdown of the boilers, as was imposed on the auxiliary boiler in the original air construction permit No. PSD-FL-010. New text is marked with double underline.

PSD-FL-010: New Specific Condition. V.11.

V.11. If at any time the permittee determines that it is appropriate to use supplemental fuel during periods of startup, shutdown, flame stabilization and low load operation, then No. 2 fuel oil and/or natural gas shall be used for the pulverized coal and petroleum coke-fired Boiler No. 1 or Boiler No. 2.

ATTACHMENT JEA-EU1-IV1b

IDENTIFICATION OF APPLICABLE REQUIREMENTS

PERMIT NO. 0310045-024-AC

PERMITTEE

JEA
21 West Church Street
Jacksonville, Florida 32202-3139

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Air Permitting North Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

PROJECT

Air Permit No. PSD-FL-010H
Project No. 0310045-024-AC
St. Johns River Power Park

This project authorizes the installation of natural gas igniters for startup, shutdown, flame stabilization and low load operation on the existing pulverized coal and petroleum coke fired Boilers Nos. 1 and 2; and it authorizes the use of the No. 2 fuel oil (FO) for flame stabilization and shutdown (already authorized to use No. 2 FO for startup and low load operation in Power Plant Siting Permit No. PA81-13). The proposed work will be conducted at the existing JEA St. Johns River Power Park facility, which is located in Duval County, Florida. The project results in a minor source air construction permit.

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on October 27, 2008. The applicant published the Public Notice of Intent to Issue in the The Florida Times-Union on October 31, 2008. The Department received the proof of publication on November 5, 2008. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

Applicant

On November 4, 2008, the Department received timely comments on the Draft Permit Revision from the applicant via an e-mail received November 4, 2008. The following summarizes the comments and the Department's response.

1. In "new" Specific Condition V.11. of the permit for Boilers Nos. 1 and 2, it was requested that an introductory phrase be added to recognize that supplemental fuel for startup, shutdown, flame stabilization and low load operation be used only if it is needed and that pulverized petroleum coke is also an authorized fuel along with pulverized coal.

   Response: The clarification and revision better describes what was intended. The Department agrees with the request and the changes were made.

CONCLUSION

The final action of the Department is to issue the permit with the minor revision and clarification as described above.

ATTACHMENT JEA-EU1-IV1c

IDENTIFICATION OF APPLICABLE REQUIREMENTS

PERMIT NO. 0310045-025-AC

Florida Department of
Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

June 4, 2009

Sent by Electronic Mail – Received Receipt Requested

Mr. James M. Chansler, P.E., D.P.A.
Chief Operating Officer
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202-3139

Re: Extension of Air Construction Permit Expiration Date
Jacksonville Electric Authority
St. Johns River Power Park Units 1 & 2 (SJRPP) Selective Catalytic Reduction (SCR) Installation
Project No. 0310045-025-AC
Extension of Original Air Permit No. 0310045-017-AC

Dear Mr. Chansler:

On April 23, 2009, Jacksonville Electric Authority (JEA) requested an extension of the expiration date for the above referenced air construction permit for the St. Johns River Power Park (SJRPP) facility located at 11201 New Berlin Road in Jacksonville, Duval County. Briefly, this project authorizes the installation of selective catalytic reduction (SCR) in Units 1 and 2 to reduce nitrogen oxides emissions. The construction activities were completed in May, 2009. However, JEA requests the additional time to complete the required testing and to prepare and submit a timely application to revise the Title V permit. The request to extend the air construction permit was timely. Construction of this project commenced within 18 months of the approval to construct, and no break in construction greater than 18 months has occurred. The project is not a phased project requiring a re-evaluation of best available control technology (BACT). Based on the circumstances and information provided, the Department approves this request.

Determination: The expiration date is hereby extended from **June 30, 2009** to **December 31, 2009** to provide the necessary time to complete required testing and to prepare and submit a timely application to revise the Title V permit to include the new systems. This permitting action does not authorize any new construction. A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The Permitting Authority responsible for making a permit determination for this project is the Bureau of Air Regulation in the Department of Environmental Protection's Division of Air Resource Management. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241). Petitions must be filed within 14 days of receipt of this permit extension. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this written notice. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Effective Date: This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this action will not be effective until further order of the Department.

Judicial Review: Any party to this permitting decision (order) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/sa/cgh

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Extension of Air Construction Permit Date was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on 6/4/09 to the persons listed below.

Mr. James M. Chansler, P.E., D.P.A., JEA (chanjm@jea.com)
Mr. John Worley, JEA (worlja@jea.com)
Ms. Heather Abrams, EPA Region IV (abrams.heather@epamail.epa.gov)
Mr. Chris Kirts, DEP-NED (christopher.kirts@dep.state.fl.us)
Mr. Richard Robinson, P.E., EQD (robinson@coj.net)
Mr. Mike Halpin, DEP-SCO (mike.halpin@dep.state.fl.us)
Ms. Catherine Collins, Fish and Wildlife Service (catherine_collins@fws.gov)
Ms. Vickie Gibson, DEP-BAR (victoria.gibson@dep.state.fl.us) (for read file)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 6/4/09 (Date)

ATTACHMENT JEA-EU1-IV1d

IDENTIFICATION OF APPLICABLE REQUIREMENTS

DEP ORDER No. 09-I-AP

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

June 22, 2009

Mr. Jay A. Worley
Director, Environmental Programs
JEA – St. Johns River Power Park
212 West Church Street
Jacksonville, Florida 32202

Dear Mr. Worley:

Enclosed is the Department's order approving JEA's St. Johns River Power Park request for an alternate testing procedure to utilize EPA Method CTM-013 (also known as Method 8A) for the determination of sulfuric acid mist emissions in lieu of EPA Method 8. This order is in response to JEA's June request to utilize EPA Method 8A in lieu of EPA Method 8 to determine compliance with sulfuric acid mist emissions limits for Boilers 1 and 2 at the St. Johns River Power Park in Jacksonville, Florida. As justification for the use of EPA Method 8A, JEA has stated that EPA Method 8 was developed to measure sulfuric acid mist emissions from sulfuric acid plants. However, this method's results suffer from interferences from high particulate levels, high moisture levels and/or the presence of ammonia in the gas stream. All of these conditions are present in these power boiler gas streams.

The Department's research has shown that EPA Method 8A was developed to address these conditions and is the preferable method for these stack conditions. Please call me at 850/921-8985 if you have any questions regarding this order.

Sincerely,

Edward J. Svec, Engineer IV
Emissions Monitoring Section
Bureau of Air Monitoring
and Mobile Sources

/ES

Enclosure

cc: Chris Kirts, DEP Northeast District
Trina Vielhauer, DARM

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:	)	Permit No.: 0310045-017-AC
	)	
JEA – St. Johns River Power Park		
	)	
	)	
Petitioner	)	File No.: 09-I-AP

ORDER ON REQUEST
FOR
ALTERNATE PROCEDURES AND REQUIREMENTS

Pursuant to Rule 62-297.620, Florida Administrative Code (F.A.C.), JEA – St. Johns River Power Park has petitioned for approval of an alternate sampling procedure for determining emissions of sulfuric acid mist (SAM) from existing boilers 1 and 2 at the St. Johns River Power Park facility located in Jacksonville, Duval County, Florida. Petitioner has requested approval for the use of Method 8A in lieu of EPA Method 8, as required by Petitioner's permit. The basis for this request is the Petitioner's assertion that the EPA Method 8 was designed for sampling at sulfuric acid plants. As such, the method is generally only useful for gas streams that have a high concentration of SO_3, no moisture, no particulates, low gas temperatures, minimal amounts of SO_2, as well as a stream free of potential interferences caused by compounds such as ammonia and certain halides.

Having considered Petitioner's written request and all supporting documentation, the following Findings of Fact, Conclusions of Law, and Order are entered:

FINDINGS OF FACT

1. On June 4, 2009, the Department received Petitioner's request to use Method 8A for the initial performance test and annual tests on Boilers 1 and 2 (Units 016 and 017) in lieu of EPA Method 8 at the St. Johns River Power Park facility.

2. Boilers 1 and 2 are fossil fuel-fired steam generators, each with a nameplate rating of 679.6 megawatts (electric). Emissions are currently controlled by an electrostatic precipitator, limestone scrubber and low-NO_X burners.

3. Air construction permit 0310045-017-AC authorizes the installation of selective catalytic reduction (SCR) systems on Boilers 1 and 2.

4. Air construction permit 0310045-017-AC requires initial performance tests using EPA Method 8 on either Boiler 1 or Boiler 2 to determine the SAM emissions rates under a variety of operating conditions. The tests shall document the impact of ammonia injection on reducing SAM emissions and shall be used to develop correlation/curves between injection rates, operating conditions and emissions. It also requires annual tests alternating between Boilers 1 and 2 using EPA Method 8 to determine SAM emissions rates and to adjust the ammonia injection rates, as necessary.

5. EPA Method 8 states: "Method 8 was developed specifically for measuring sulfur dioxide emissions from sulfuric acid manufacturing plants. These sources have relatively clean and dry emission streams with few or no interferences. Method 8 works very well for these kinds of sources."

6. EPA Method 8 also states: "Because Method 8 is the only method EPA has published for measuring sulfuric acid/sulfur trioxide emission, it has been applied to many source categories other than the one for which it was developed. It may not work very well for some source categories and may not be appropriate for measuring sulfur oxide emissions from them. It should not be used to measure sulfur acid/sulfur trioxide from the following sources:

1. Those sources that have significant emissions of solid sulfates that are water soluble. Solid sulfates are compounds like sodium sulfate.
2. Those sources that have significant emissions of sulfur dioxide and ammonia."

7. Combustion of fossil fuel in the boilers produces large amounts of particulate matter and water vapor. The limestone scrubbers are another source of water vapor in the gas streams.

8. Selective catalytic reduction systems are used to control NO_x emissions by injecting ammonia into the gas stream, which then reacts with the NO_x to form water and nitrogen. The use of SCR systems always results in some residual ammonia in the gas streams.

9. The American Society for Testing and Materials (ASTM) drafted Method D3226-73T, commonly referred to as the "Controlled Condensation Method," to address interferences to EPA Method 8 encountered in typical Kraft recovery furnaces. The National Council for Air and Stream Improvements, Inc., (NCASI) issued a revision to this controlled condensation method in December 1996, which it called "Method 8A – Determination of Sulfuric Acid Vapor or Mist and Sulfur Dioxide Emissions from Kraft Recovery Furnaces." This method has been adopted by EPA as CTM-013.

CONCLUSIONS OF LAW

1. The Department has jurisdiction to consider Petitioner's request pursuant to Section 403.061, Florida Statutes (F.S.), and Rule 62-297.620, F.A.C.

2. Petitioner has provided reasonable assurance that this alternate sampling procedure is necessary and will produce acceptable results. The Department's conclusion is based upon review and comparison of both test methods and professional experience with EPA Methods 8 and CTM-013.

ORDER

Having considered Petitioner's written request and supporting documentation, it is hereby ordered that:

1. In lieu of EPA Method 8, Petitioner may utilize EPA Method CTM-013 to determine SAM emissions from Boilers 1 and 2 at the St. Johns River Power Park facility in Jacksonville.

2. This Order shall not abrogate Petitioner's obligation to comply with any monitoring requirements established pursuant to the provisions of the federal Clean Air Act (42 USC 1857, et seq) as amended in 1990.

PETITION FOR ADMINISTRATIVE REVIEW

The Department's Proposed Agency Action will become final upon expiration of the petition period described below unless a timely petition for an Administrative Hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the Proposed Agency Action may petition for an Administrative Proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within 21 days of receipt of this Notice of Intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 21 days of publication of the Public Notice or within 21 days of receipt of this notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for Notice of Agency Action may file a petition within 21 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an Administrative Determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a Motion in Compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;

(c) A statement of how and when petitioner received notice of the agency action or proposed action;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;

(e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action;

(f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and

(g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the Administrative Hearing process is designed to formulate Final Agency Action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

NOTICE OF APPEAL RIGHTS

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice must be filed within 30 days after this order is filed with the Clerk of the Department.

DONE AND ORDERED this 17th day of June, 2009, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Joseph Kahn, Director
Division of Air Resource Management
Mail Station 5500
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 921-9540

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Martha J Wise 6/17/09
(Clerk) (Date)

ATTACHMENT JEA-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT JEA-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

SJRPP Boiler Nos. 1 and 2 are permitted to operate while firing coal, a coal blend with a maximum of 30 percent petroleum coke (by weight) (30-day rolling average), "on-specification" used oil, or a blend of these fuels. In addition, these units can use natural gas and No. 2 distillate fuel oil for startup, shutdown, low load operation and flame stabilization.

The maximum weight of petroleum coke burned shall not exceed 150,000 pounds per hour, based on a 30-day rolling average.

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.

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

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
   NGS - Circulating Fluidized Bed Boiler No. 1

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

   ☐ Hg Budget Unit

9. Package Unit:
   Manufacturer: Model Number:

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

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

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

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- Circulating Fluidized Bed Boiler No. 2 (EU026) shares a common stack with NGS - Circulating Fluidized Bed Boiler No. 1 (EU027). 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: **700,300** 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 5

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Bituminous/Subbituminous 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 each boiler.**		

Segment Description and Rate: Segment 2 of 5

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 each boiler.**		

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

Segment Description and Rate: Segment 3 of 5

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/yr x 1 yr/8,760 hr = 102.5 x 10^6 cf/hr** **Represents total landfill gas to both boilers.**		

Segment Description and Rate: Segment 4 of 5

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 **5**

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 _____ of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

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
HCl (H106)	013		NS
HAPs			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: **498** lb/hour **2,180** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.09 lb/MMBtu (30-day rolling average)** Reference: **Permit No. 0310045-022-AC/PSD-FL-265E**	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: Hourly NOx emissions rate: 0.09 lb/MMBtu x 2,764 MMBtu/hr = 249 lb/hr
Each unit: Annual NOx emissions rate: 249 lb/hr x 8,760 hr/yr x ton/2000 lb = 1,090 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Emission limit is based on a 30-day rolling average.
Emissions represent total for 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 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: **3,316** 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 Units 1, 2, and 3 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: **700** lb/hour **3,066** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **350 lb/hr, each boiler** Reference: **Permit No. 0310045-022-AC/PSD-FL-265E**	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 CO emissions rate: 350 lb/hr x 8,760 hr/yr x ton/2000 lb = 1,533 ton/yr**	
11. Potential, Fugitive, and Actual Emissions Comment: **CO emissions limit based on a 24-hour block average. Emissions represent total for 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 **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. 0310045-022-AC/PSD-FL-265E 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 **1,533** 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: **1,106** lb/hour **3,632** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.20 lb/MMBtu (24-hour block average)** **0.15 lb/MMBtu (30-day rolling average)** Reference: **Permit No. 0310045-022-AC/PSD-FL-265E**	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: Hourly SO_2 emissions rate (24-hour average): 0.20 lb/MMBtu x 2,764 MMBtu/hr = 553 lb/hr
Each unit: Hourly SO_2 emissions rate (30-day average): 0.15 lb/MMBtu x 2,764 MMBtu/hr = 415 lb/hr
Each unit: Annual SO_2 emissions rate = 415 lb/hr x 8,760 hr/yr x ton/2000 lb = 1,816 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

SO_2 emissions limit based on a 24 hour block average and a 30 day rolling average. Emissions represent total for 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 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 **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. 0310045-022-AC/PSD-FL-265E** **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: **830** 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. 0310045-022-AC/PSD-FL-265E** **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: **3,316** lb/hour **14,528** 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: **28** lb/hour **123** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **14 lb/hr (3-hour average), each boiler** Reference: **Permit No. 0310045-022-AC/PSD-FL-265E**	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 VOC emissions rate = 14 lb/hr x 8,760 hr/yr x ton/2000 lb = 61.32 ton/yr**	
11. Potential, Fugitive, and Actual Emissions Comment: **VOC emissions limit based on a 3 hour average. Emissions represent total for 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 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: **Compliance with CO limits based on CEMS data can be used as surrogate.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-022-AC/PSD-FL-265E.** **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: **60** lb/hour **266** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.011 lb/MMBtu (3-hour average)** Reference: **Permit No. 0310045-022-AC/PSD-FL-265E**	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: Hourly PM emissions rate: 0.011 lb/MMBtu x 2,764 MMBtu/hr = 30 lb/hr
Each unit: Annual PM emissions rate: 30 lb/hr x 8,760 hr/yr x ton/2000 lb = 133 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
PM emissions limits are based on a 3 hour average.
Emissions represent total for 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 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: **60** 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.**	

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.**	

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: **60** lb/hour **266** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.011 lb/MMBtu (3-hour average)** Reference: **Permit No. 0310045-022-AC/PSD-FL-265E**	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: Hourly PM10 emissions rate: 0.011 lb/MMBtu x 2,764 MMBtu/hr = 30 lb/hr
Each unit: Annual PM10 emissions rate: 30 lb/hr x 8,760 hr/yr x ton/2000 lb = 133 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
PM10 emissions limit are based on a 3 hour average.
Emissions represent total for 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 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: **60** 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.**	

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.**	

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. 0310045-022-AC/PSD-FL-265E**	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 tons/yr**	
11. Potential, Fugitive, and Actual Emissions Comment: **Mercury emissions are based on a 6 hour average. Emissions represent total for 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 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: **Compliance with Hg limits based on CEMS.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-022-AC/PSD-FL-265E. 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: **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. 0310045-022-AC/PSD-FL-265E**	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 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Lead emissions are based on a 3 hour average.
Emissions represent total for 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 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: **EPA Method 12 or 29**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-022-AC/PSD-FL-265E. 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: **2.2** lb/hour **9.64** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.1 lb/hour (3-hour average), each boiler** Reference: **Permit No. 0310045-022-AC/PSD-FL-265E**	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 SAM emissions rate: 1.1 lb/hr x 8,760 hr/yr x ton/2000 lb = 4.82 tons/yr**	
11. Potential, Fugitive, and Actual Emissions Comment: **SAM emissions are based on a 3 hour average. Emissions represent total for 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 **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: **EPA Method 8**	
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. 0310045-022-AC/PSD-FL-265E** **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. 0310045-022-AC/PSD-FL-265E**	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:
HF emissions are based on a 3 hour average.
Emissions represent total for 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 **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: **EPA Method 13A or 13B**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-022-AC/PSD-FL-265E. 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. 0310045-020-AV**	

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: % 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:	6. Performance Specification Test Date: **June 10, 2002**
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: **TECO** Model Number: **48C**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date: **June 10, 2002**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 70175-365** **Serial Number: NGS CFB Boiler No. 2: 70174-365**	

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: **42C**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date: **June 10, 2002**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 42C- 69020-362** **Serial Number: NGS CFB Boiler No. 2: 42C- 69028-362**	

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: **43C**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date: **June 10, 2002**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 43C- 69843-364** **Serial Number: NGS CFB Boiler No. 2: 42C- 69844-364**	

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: **CAI** Model Number: **ZRH**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date: **June 10, 2002**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: AOXO606T** **Serial Number: NGS CFB Boiler No. 2: AOXO603T**	

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-EU2-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: **JEA-EU2-I2** ☐ 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 **7/03/08**

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 **7/03/08**
   ☐ 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): **September 11, 2009**
   Test Date(s)/Pollutant(s) Tested: **July 28, 2009 / Lead**
   ☐ 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

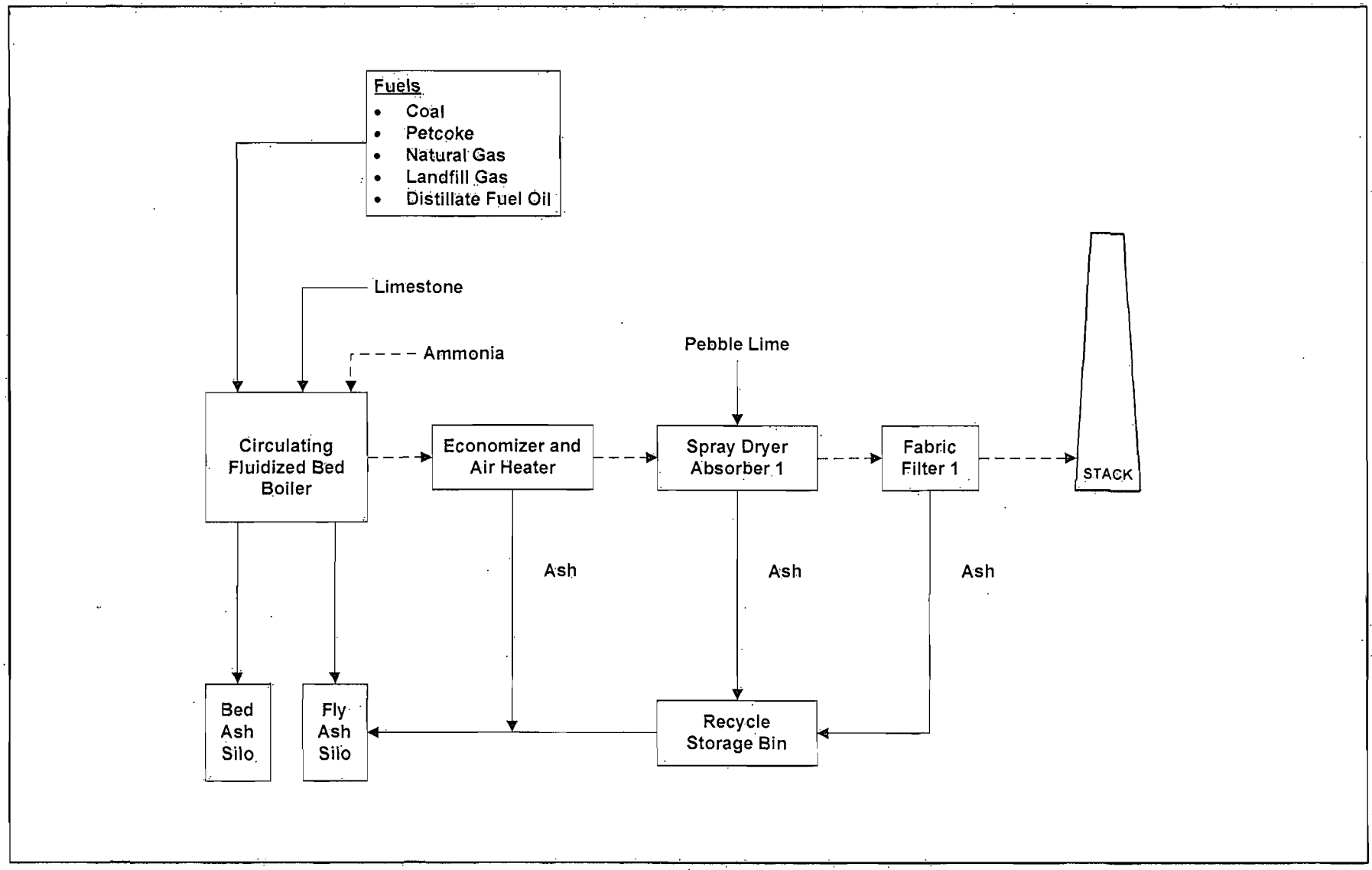
1. Identification of Applicable Requirements:	☒ Attached, Document ID: JEA-EU2-IV1
2. Compliance Assurance Monitoring:	☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation:	☒ Attached, Document ID: JEA-EU2-IV3 ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading):	☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements Comment

Attachment A

ATTACHMENT JEA-EU2-I1

PROCESS FLOW DIAGRAM



Attachment JEA-EU2-I1
Process Flow Diagram
Northside Generating Station Units 1 and 2

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: JEA-EU2-I1.vsd
Date: 08/07/09

Golder Associates

ATTACHMENT JEA-EU2-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT JEA-EU2-I2

FUEL ANALYSIS SPECIFICATION FOR LANDFILL GAS
JACKSONVILLE ELECTRIC AUTHORITY
CFB BOILER NOS 1 AND 2

Parameter	Sample #1 Before Flare	Sample #2 Well No. 2
Methane (%)	51.4	52.9
Carbon Dioxide (%)	39.9	38.4
Oxygen (%)	0.7	0.1
Unknown (%)	8.0	8.6
Temperature (F)	682	94
Flow (cfm)	430	27
H_2S [1] (GEM 2000, ppm)	48.3	NM
H_2S [2] (Draeger, ppm)	<50	NM

*NM- No measurement taken

1 - GEM 2000 Analyzer method

2 – Draeger method

ATTACHMENT JEA-EU2-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

In the Matter of an
Application for Permit Revision by:

JEA
21 West Church Street
Jacksonville, Florida 32202

Air Permit No. PSD-FL-265E
Project No. 0310045-022-AC
Northside Generating Station
Spray Dryer Absorber Maintenance/Repair

Authorized Representative:
Mr. James M. Chansler, P.E., D.P.A – Chief Operating Officer

PROJECT AND LOCATION

JEA operates the existing Northside Generating Station located at 4377 Heckscher Drive, Jacksonville, Duval County, Florida. The facility is an electric utility. This permit revises certain specific conditions of air construction permit 0310045-003-AC/PSD-FL-265, authorizing that the spray dryer absorber can be taken off-line for maintenance and/or repair while keeping the circulating fluidized bed boiler operational with additional injection of limestone to the boiler. This permit revision also incorporates all the previous modifications associated with Air Permit No. PSD-FL-265. The permit revision will update Section III – Emissions Units Specific Conditions as it relates to the previous modifications. Additionally, this permit revision will attach as an appendix all the previous modifications to Air Permit No. PSD-FL-265 and the quality assurance/quality control (QA/QC) plan for the mercury (Hg) continuous emission monitoring system (CEMS).

STATEMENT OF BASIS

This permit revision is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and the Florida Administrative Code (F.A.C.) Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

CONTENTS

Section III	Emissions Units Specific Conditions
Appendix Hg CEMS	QA/QC Plan
Appendix Modification	Previous Modifications to Air Permit No. PSD-FL-265

Note: Double underlined indicates additions and strikethrough indicates deletions in the permit revision.

Joseph Kahn, Director
Division of Air Resource Management

(Date)

APPLICABLE STANDARDS AND REGULATIONS

1. Applicable Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296 and 62-297. The subject emission units at Northside are also subject to following requirements of the Code of Federal Regulations Section 40, Part 60 (1998 version), adopted by reference in the Florida Administrative Code Rule 62-204.800 (as applicable):

(a) Subpart A, General Provisions, Sections 60.7, 60.8, 60.11, 60.12, 60.13, and 60.19;

(b) Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 (Northside Units 1 and 2);

(c) Subpart Y, Standards of Performance for Coal Preparation Plants (coal handling at Northside, excluding open storage piles); and

(d) Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants (limestone handling at Northside, except for open storage piles and truck unloading).

Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

GENERAL OPERATION REQUIREMENTS

2. Capacity: The maximum heat input rates to Northside Units 1 and 2 shall not exceed 2764 mmBtu/hr, per unit. The maximum heat input rates to the three limestone dryers shall not exceed 57.9 mmBtu/hr, for all three units combined. These rates are included only for purposes of determining capacity during compliance stack tests. Continuous compliance with these rates is not required; capacity during compliance testing shall be determined based on fuel flow data and the as-fired heat content of the fuel. **[Rule 62-210.200(228), F.A.C.]**

   [Permitting note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program (40 CFR Part 75) conservatively overestimates heat input ratings. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certifications.]

3. Maximum Allowable Hours: Northside Units 1 and 2 and the materials handling operations may operate continuously (i.e., 8760 hours per year). **[Rule 62-210.200(228), F.A.C.]**

4. Fuels: Only coal, coal coated with latex, petroleum coke, No. 2 fuel oil (maximum sulfur content of 0.05 percent by weight), and natural gas, shall be fired in Units 1 and 2. Only No. 2 fuel oil (maximum sulfur content of 0.05 percent by weight) and natural gas shall be fired in the three limestone dryers. **[Rule 62-210.200(228), F.A.C.]**

5. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering, seeding, and application of water or chemicals to the affected areas, as necessary. After construction and during operation, the following measures shall be taken, in addition to requirements for materials handling operations specifically addressed herein, to minimize unconfined particulate matter emissions: maintenance of paved areas as needed, regular mowing of grass and care of vegetation, limiting access to plant property by unnecessary vehicles, storage of bagged chemical products in weather-tight buildings (except for fertilizer), and prompt cleanup of spilled powdered chemical products. **[Rule 62-296.320(4)(c), F.A.C.]**

6. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, JEA shall notify Environmental Quality Division (EQD) as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. **[Rule 62-4.130, F.A.C.]**

7. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. **[Rule 62-4.070(3), F.A.C.]**

8. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. **[Rule 62-210.650, F.A.C.]**

CONTROL TECHNOLOGY - CIRCULATING FLUIDIZED BED (CFB) BOILERS

9. Sulfur Dioxide, Acid Gases and Metals Control: Sulfur dioxide (SO_2) and acid gases shall be controlled by the injection of limestone into the CFB boiler beds. Residual sulfur dioxide, acid gases and metals shall be further controlled by the use of add-on air quality control systems for Units 1 and 2. The add-on air quality control systems installed by JEA and approved by the Department are spray dryer absorber (SDA) systems (one for Unit 1 and one for Unit 2) and fabric filters (one for Unit 1 and one for Unit 2). During periods when an SDA is non-operational due to malfunction, maintenance or repair, limestone injection to the associated CFB boiler shall be increased to the extent needed to ensure that the SO_2 emission limits in Condition 12 for Units 1 and 2 of 0.2 lb/mmBtu, 24-hr block average, and 0.15 lb/mmBtu, 30-day rolling average are achievable. Non-operation of the SDA is limited to a maximum of 12 hours per month per unit (12-month rolling average). **[Applicant Request; and 0310045-022-AC/PSD-FL-265E]**

10. Oxides of Nitrogen Control: A selective non-catalytic reduction (SNCR) system designed to meet a limit of 0.09 lb/mmBtu, 30-day rolling average, shall be used on Units 1 and 2 for control of oxides of nitrogen (NOx) emissions. **[Rule 62-212.400, F.A.C.]**

11. Particulate Matter Control: Particulate matter (PM and PM_{10}) shall be controlled by the use of high efficiency, add-on air quality control devices (either fabric filters or electrostatic precipitators) on Units 1 and 2 that are designed to meet a limit of 0.011 lb/mmBtu. The permittee shall identify the devices selected and shall provide design specifications to the Department at least 90 days prior to installation of the devices. **[Rule 62-212.400, F.A.C.]**

EMISSION LIMITS AND STANDARDS

The following shall apply upon completion of the initial compliance tests, certification tests, and performance specification tests, as applicable and per pollutant, for each of the repowered Units 1 and 2, except as noted:

12. Best Available Control Technology: The following is a summary of the BACT determinations by DEP of the Repowered Units 1 and 2, and other limits requested by the applicant, as noted.

Table 1. Emission Limits for Units 1 and 2

Pollutant	Emission Limits– Per Unit
Visible emissions	10 percent opacity, 6-minute block average
SO_2 [2]	0.2 lb/mmBtu, 24-hour block average[2, 3] 0.15 lb/mmBtu, 30-day rolling average [2]
NO_x [1]	0.09 lb/mmBtu, 30-day rolling average[4]
PM/PM_{10} [1]	0.011 lb/mmBtu, 3-hour average [1]
CO [1]	350 lbs/hour, 24-hour block average [1,3]
VOCs [1]	14 lbs/hour, 3-hour average [1]
Pb [2]	0.07 lb/hour, 3-hour average [2]
H_2SO_4 [2]	1.1 lbs/hour, 3-hour average [2]
HF [1]	0.43 lb/hour, 3-hour average [1]
Hg [1]	0.03 lb/hour, 6-hour average [1]

[1]BACT determination.

[2]Requested by applicant.

[3]24-hour block averages are calculated from midnight to midnight.

[4]Equivalent to approximately 0.8-0.9 lb/MWhr (gross energy output).

13. Visible Emissions: Visible emissions from Units 1 and 2 shall not exceed 10 percent opacity, 6-minute block average, excluding periods of startup, shutdown, and malfunction. **[Rule 62-212.400, F.A.C.]**

14. Sulfur Dioxide:

(a) Sulfur dioxide (SO_2) emissions from Units 1 and 2 shall not exceed 0.20 lb/mmBtu (24-hour block average) nor 0.15 lb/mmBtu (30-day rolling average). **[Applicant request.] The equivalent emissions, being provided for informational purposes only, are 553 lbs/hour (24-hour block average), 415 lbs/hour (30-day rolling average), and 1,816 tons per year, per unit.**

(b) Sulfur dioxide from Units 1, 2, and 3 combined shall not exceed 12,284 tons during any consecutive 12-month period on a rolling basis. This condition shall become effective on the first day of the month following successful completion of the initial performance testing of Repowered Unit 2, and compliance shall be based upon at least 12 months of operation after the effective date. **[Applicant request.]**

15. Oxides of Nitrogen:

(a) Oxides of nitrogen (NO_x) emissions from Units 1 and 2 shall not exceed 0.09 lb/mmBtu on a 30-day rolling average basis. **[Rule 62-212.400, F.A.C.] The equivalent emissions, being provided for informational purposes only, are 249 lbs/hour (30-day rolling average) and 1,090 tons per year, per unit.**

(b) Oxides of nitrogen emissions from Units 1, 2, and 3 combined shall not exceed 3,600 tons during any consecutive 12-month period on a rolling basis. This condition shall become effective on the first day of the month following successful completion of the initial

performance testing of Repowered Unit 2, and compliance shall be based upon at least 12 months of operation after the effective date. **[Applicant request.]**

16. Particulate Matter (PM and PM_{10}):

(a) Particulate matter (PM) emissions from Units 1 and 2 shall not exceed 0.011 lb/mmBtu (3-hour average). **[Rule 62-212.400, F.A.C.] The equivalent emissions, being provided for informational purposes only, are 30 lbs/hour (3-hour average) and 133 tons per year, per unit.**

(b) Particulate matter-10 microns or smaller (PM 10) emissions from Units 1 and 2 shall not exceed 0.011 lb/mmBtu (3-hour average). **[Rule 62-212.400, F.A.C.] The equivalent emissions, being provided for informational purposes only, are 30 lbs/hour (3-hour average) and 133 tons per year, per unit.**

(c) Stack emissions of particulate matter (PM) from Units 1, 2, and 3 combined shall not exceed 881 tons during any consecutive 12-month period on a rolling basis. This condition shall become effective on the first day of the month following successful completion of the initial performance testing of Repowered Unit 2, and compliance shall be based upon at least 12 months of operation after the effective date. **[Applicant request.]**

17. Carbon Monoxide: Carbon monoxide (CO) emissions shall not exceed 350 lbs/hour, 24-hour block average, nor 1533 tons per year from either Unit 1 or 2. **[Annual limit—applicant request.]**

18. Volatile Organic Compounds: Volatile organic compound (VOC) emissions shall not exceed 14 lbs/hour (3-hour average), nor 61.5 tons per year from either Unit 1 or 2. **[Annual limit—applicant request.]**

19. Lead: Lead (Pb) emissions shall not exceed 0.07 lb/hour (3-hour average), from either Unit 1 or 2. **[Applicant request.]**

20. Sulfuric Acid Mist: Sulfuric acid mist (H_2SO_4) emissions shall not exceed 1.1 lbs/hour (3-hour average), from either Unit 1 or 2. **[Applicant request]**

21. Hydrogen Fluoride: Hydrogen fluoride (HF) emissions shall not exceed 0.43 lb/hour (3-hour average), from either Unit 1 or 2. **[Rule 62-212.400, F.A.C.]**

22. Mercury: Mercury (Hg) emissions shall not exceed 0.03 lb/hour (6-hour average), from either Unit 1 or 2. **[Rule 62-212.400, F.A.C.]**

MATERIALS HANDLING OPERATIONS

23. Throughput rates: The materials handling and usage rates for coal, coal coated with latex, petroleum coke, and limestone at Northside shall not exceed the following (for Northside Units 1 and 2 combined), assuming a moisture content of 5.5% or less:

Material	Handling/Usage Rate Tons Per Year
Coal/Coal coated with latex/ Petroleum Coke	2.42 million
Limestone	1.45 million

24. Standards:. The materials handling sources at Northside shall be regulated as follows, and the emission limits and standards shall apply upon completion of the initial compliance tests for each of the units or activities.

(a) The following materials handling sources shall be equipped with fabric filter controls and visible emissions shall not exceed 5 percent opacity:

Crusher house building baghouse exhaust (EU29)
Fuel silos dust collectors (EU31)
Limestone prep building dust collectors (EU34)
Limestone silos bin vent filters (EU35)
Fly ash transport blower discharge (EU36)
Fly ash silos bin vents (EU37)
Bed ash silos bin vents (EU38)
AQCS pebble lime silo (EU42)
Fly ash slurry mix system vents (EU51)
Bed ash slurry mix system vents (EU52)
Bed ash surge hopper bin vents (EU53)

(b) The following materials handling sources shall use wet suppression, water spray, coverings, and/or conditioned materials to control particulate emissions as needed, and visible emissions shall not exceed 5 percent opacity:

Transfer towers (EU28c, EU28g, EU28i, EU28o, EU28q and EU28v)
Coal/Coal coated with latex and petroleum coke storage building (EU28h)
Transfer Building 5 and limestone loadout chute (EU28d)
Belt Conveyor No. 1 (EU28)

(c) The following materials handling sources shall use wet suppression, water spray, partial enclosures, and/or conditioned materials to control particulate emissions as needed, and visible emissions shall not exceed 10 percent opacity:

Northside dock vessel unloading operations – vessel hold (EU28a)
Northside dock vessel unloading operations -- vessel unloader & spillage conveyors (EU28a)
Limestone storage pile (EU28p)
Limestone reclaim hopper (EU28p)

(d) The limestone dryer/mill building (EU33) shall have no visible emissions (other than from a baghouse vent).

(e) The maximum particulate matter emissions from the following operations shall not exceed 0.01 grains per dry standard cubic foot:

Limestone prep building dust collectors (EU34)
Limestone silo bin vent filters (EU35)

LIMESTONE DRYERS

25. Limestone dryers: The maximum emissions from each of the three limestone dryers shall not exceed the following limits, which are established as BACT by the Department. These limits shall become effective upon completion of the initial compliance tests:

Pollutants	Limits
Visible Emissions	5% Opacity
Sulfur Dioxide	Maximum 0.05% sulfur No. 2 distillate oil
Particulate Matter	0.01 grains per dry standard cubic foot

EXCESS EMISSIONS

26. Authorized Emissions: Notwithstanding other emission limits and standards established by this permit, excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided (1) that best operational practices are adhered to and (2) the duration of excess emissions shall be minimized but not exceed sixty (60) hours in any calendar month per emissions unit (CFBs Units Nos. 1 and 2). The permittee shall keep operational records necessary to demonstrate compliance with this restriction. Emissions data collected during periods of startup, shutdown and malfunction shall be included when demonstrating compliance with annual emission limits. The CFB Units shall not be started up at the same time. The permittee shall update the written procedure summarizing the current best operational practices to be followed every 5 years (at operating permit renewal).

Pursuant to Rule 62-210.200, F.A.C., Definitions, the following are defined:

a. Startup: The commencement of operation of any emissions unit which has been shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

b. Shutdown: The cessation of the operation of an emissions unit for any purpose.

c. Malfunction: Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

In case of excess emissions resulting from malfunction, each owner or operator shall notify the Department or appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department or appropriate Local Program.

[Rules 62-210.200 and 62-210.700(1), (5) & (6), F.A.C.; and 0310045-015-AC/PSD-FL-265C]

27. Non-authorized Emissions: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited pursuant to **Rule 62-210.700, F.A.C**

28. Excess Emissions Report: If excess emissions occur due to malfunctions for a period of more than two hours, the owner or operator shall notify EQD within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct

the problem. In addition, the Department may require a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. **[Rules 62-4.130 and 62-210.700(6), F.A.C.]**

COMPLIANCE DETERMINATION

29. Initial Performance Tests and CEMS Certifications: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which each unit will be operated, but not later than 180 days of initial operation, and periodically thereafter as indicated in this permit. Initial compliance tests shall be performed on Units 1 and 2 while firing either coal or petroleum coke as indicated below, and on the limestone dryers while firing fuel oil. Annual compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on Units 1 and 2 while firing either coal or petroleum coke as indicated below. No stack tests are required if continuous emissions monitoring systems are used to demonstrate compliance pending EPA approval, otherwise initial performance tests shall be conducted as described above. Certification tests (or performance evaluations, as applicable) for all Continuous Emissions Monitoring System (CEMS) required by this permit must be completed within 60 days after achieving the maximum production rate at which each unit will be operated but not later than 90 days of initial operation, and prior to the initial stack tests for that unit.

Note: No methods other than the ones identified below may be used for compliance testing unless prior DEP or EQD approval is received in writing. DEP or EQD may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

30. Visible Emissions (Opacity):

(a) Compliance with the visible emissions limit in Condition 13 shall be demonstrated with continuous opacity monitors installed, certified, operated, and maintained in accordance with 40 CFR Part 75, based on 6-minute block averages and excluding periods of startup, shutdown, and malfunction.

(b) Compliance with the visible emissions limit in Condition 25 for the limestone dryers shall be demonstrated using EPA Method 9 initially and once within every five years thereafter. The limestone dryers shall fire fuel oil during the initial compliance tests. In subsequent years, the testing shall be conducted annually if fuel oil has been fired for more than 400 hours during the previous federal fiscal year; otherwise, the testing shall be conducted once within every five years, even if the testing is conducted while firing natural gas.

31. Sulfur Dioxide:

(a) Compliance with sulfur dioxide (SO_2) emissions limits in Conditions 14(a) and 14 (c) shall be demonstrated with Continuous Emissions Monitoring Systems (CEMS's) installed, certified, operated and maintained in accordance with 40 CFR Part 75, based on 24-hour block and 30-day rolling averages, as applicable, and excluding periods of startup, shutdown, and malfunction. Emissions recorded in parts per million shall be converted to lb/mmBtu using an

appropriate F-factor for purposes of determining compliance with the emission limits in Conditions 14(a) and 14(c).

(b) Compliance with the annual SO_2 emission limit in Condition 14(b) shall be determined based on SO_2 data from the CEMS's. Emissions during periods of startup, shutdown, and malfunction shall be considered in determining the total annual emissions. [Applicant request.]

[Permitting Note: At least three (3) hours of data are required to establish a 24-hour average for CEMS data.]

32. Oxides of Nitrogen:

(a) Compliance with the oxides of nitrogen (NOx) emissions limit in Condition 15(a) shall be demonstrated with a CEMS's installed, certified, operated and maintained in accordance with 40 CFR Part 75, based on a 30-day rolling average and excluding periods of startup, shutdown and malfunction. The 30-day rolling averages will be determined based on hourly values calculated in accordance with Appendix F of 40 CFR Part 75.

(b) Compliance with the annual NOx emissions limit in Condition 15(b) shall be determined by summing the products of hourly NOx emission rate and heat input rate data from the CEMS's. Emissions during periods of startup, shutdown, and malfunction shall be considered in determining the total emissions. [Applicant request.]

33. Particulate Matter:

(a) Initial compliance tests only shall be performed on Units 1 and 2 using EPA Methods 5, 5B, 8, 17, or 29 to determine compliance with the particulate matter (PM) limits in Condition 16(a) while firing petroleum coke, and an additional initial compliance test shall be performed on Unit 2 while firing coal. Quarterly tests shall be conducted for the first two years (eight quarters), then annually thereafter while firing petroleum coke. If petroleum coke has been fired for less than 100 hours during the previous quarter or less than 400 hours during the previous federal fiscal year, the testing may be performed while firing coal.

(b) Initial and annual compliance tests shall be performed on Units 1 and 2 using EPA Methods 201 or 201A, to determine compliance with the particulate matter-10 microns or smaller (PM_{10}) limits in Condition 16(b) while firing petroleum coke, and an additional initial test shall be performed on Unit 2 while firing coal. If petroleum coke has been fired for less than 400 hours during the previous federal fiscal year, the annual testing may be performed while firing coal.

(c) Compliance with the annual particulate matter (PM) emissions limit in Condition 16(c) shall be determined using the following formula. This formula shall be used for each fuel consumed by each of CFB Boilers Nos. 1 and 2 and existing Boiler No. 3, and the resulting PM emissions summed to obtain a 12-month total for CFB Boilers 1 and 2 and existing Boiler No. 3. [Applicant request.]

PM Emissions = (Fuel Usage[a]) x (Emission Factor[b]) x unit conversion factors

[a]The "Fuel Usage" shall be measured by calibrated fuel flow meters (±5 percent accuracy) and recorded daily when a unit is operated.

[b]An "Emissions Factor" of [(9.19 x weight percent sulfur content) + 3.22] pounds per thousand gallons (lbs/10^3 gal) shall be used for fuel oil burned in existing Boiler No. 3. The weight percent sulfur content shall be determined based on an analysis of a representative sample of the fuel oil being consumed. The analysis shall be performed using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition. An "Emissions Factor" of 5 pounds per million cubic feet (lb/MCF) shall be used for natural gas burned in existing Boiler No. 3. For Repowered Units 1 and 2, the "Emissions Factor" shall be based on particulate matter stack test results using EPA Methods 5, 5B, 8, 17, or 29 for the individual units, and shall apply to the quantities of fuel consumed in the individual units during the period immediately following the stack tests for the respective units until subsequent stack tests are completed.

(d) Initial compliance tests only shall be performed on the limestone dryers to determine compliance with the particulate matter limit in Condition 25 using EPA Method 5.

34. Carbon Monoxide:

(a) Compliance with the short-term carbon monoxide (CO) limit in Condition 17 shall be demonstrated with CEMS's installed, calibrated, operated, and maintained in accordance with 40 CFR Part 60, Appendix B based on a 24-hour block average and excluding periods of startup, shutdown, and malfunction.

(b) Compliance with the annual CO limit in Condition 17 shall be demonstrated by summing the products of hourly CO emission rate and heat input rate data from the CEMS's. Emissions during periods of startup, shutdown, and malfunction shall be considered in determining the total emissions. [Applicant request.]

35. Valid Data: For the continuous monitoring systems required under Conditions 31(a), 32(a), and 34(a), the permittee shall determine compliance based on CEMS data at the end of each operating day (midnight to midnight), new 24-hour block and 30-day average emission rates shall be calculated from the arithmetic average of all valid hourly emission rates during the previous 24-hours or 30 operating days, as appropriate. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 where emissions exceed the standards in Table 1. These excess emission periods shall be reported as required in Section II, Condition 13. A valid hourly emission rate shall be calculated for each hour in which at least two concentrations are obtained at least fifteen (15) minutes apart.

36. Volatile Organic Compounds: Initial compliance tests shall be performed on Units 1 and 2 using EPA Method 18, 25, or 25A to determine compliance with the volatile organic compound (VOC) emission limit in Condition 18 while firing petroleum coke, and an additional initial test shall be performed on Unit 2 while firing coal. Compliance testing shall also be conducted once within every five years thereafter while firing petroleum coke and/or coal. Compliance with the CO limits based on CEMS data shall be used as surrogates to indicate compliance with the VOC limits.

37. Lead: Initial compliance tests only shall be performed on Unit 2 using EPA Method 12 or 29 to determine compliance with the lead emission limit in Condition 19 while firing coal and while firing petroleum coke. An additional compliance test shall be conducted once every five years at permit renewal on one of the units while firing petroleum coke or coal or any mix of the two fuels and with the SDA down for maintenance. Within 6 months after the effective date of this permit revision, a

compliance test for lead shall be conducted on approximately 80 percent pet coke and 20 percent coal with the SDA down for maintenance. Subsequently, if the normal fuel mix to the CFB boilers is changed to 25 percent (or greater) coal for a period of more than 15 days, and the SDA requires scheduled maintenance, then an additional compliance test shall be conducted at a typical fuel mix within 60 days after the change is made and while the SDA is down for maintenance.
[Rule 62-4.070(3), F.A.C.; and 0310045-022-AC/PSD-FL-265E]

38. Sulfuric Acid Mist: Initial compliance tests only shall be performed on Unit 2 using EPA Method 8 to determine compliance with the sulfuric acid mist emission limit in Condition 20 while firing petroleum coke and while firing coal. In addition, compliance with the SO_2 limits based on CEMS data shall be used as a surrogate to indicate compliance with the sulfuric acid mist limit.

39. Hydrogen Fluoride: Initial compliance tests only shall be performed on Unit 2 using EPA Method 13A or 13B to determine compliance with the hydrogen fluoride emission limit in Condition 21 while firing coal and while firing petroleum coke.

40. Mercury: Initial compliance tests only shall be performed on Unit 2 using EPA Methods 29, 101, or 101A to determine compliance with the mercury emission limit in Condition 22 while firing coal and while firing petroleum coke.

41. Materials Handling Operations: Visible emissions tests shall be conducted on the material handling operations to determine compliance with applicable limits, as follows:

Emissions Units at Northside	EPA Method(s)	Duration of VE Test	Frequency	Material
Vessel Hold (EU 28a)	9	30 min	I only	C or PC
Vessel Unloader & Spillage Conveyors (EU 28a)	9	3 hr	I only	C & LS
Belt Conveyor No. 1 (EU 28)	9	3 hr	I only	C & LS
Transfer Towers (EU 28c, 28g, 28i, 28o, 28q & 28v)	9	3 hr	I only	C & LS
Fuel Storage Building (EU28h)	9	30 min	I only	C or PC
Limestone Storage Pile (EU28p)	9	30 min	I only	LS
NSPS - OOO				
Limestone Dryer/Mill Building (EU33)	22	IVE - 75 min	I only	LS
Limestone Prep Building Dust Collectors - Baghouse Exhaust (EU34)	9-VE 5-PM	IVE - 60 min RVE - 30 min	Meth 9: I & R Meth 5: I only	LS
Limestone Silos Bin Vent Filters - Baghouse Exhaust (EU35)	9-VE 5-PM	IVE - 60 min RVE - 30 min	Meth 9: I & R Meth 5: I only	LS
NSPS – Y				
Crusher House Building Baghouse Exhaust (EU29)	9	IVE - 3 hr RVE - 30 min	I & R	C &/or PC
Fuel Silos Dust Collectors - Baghouse Exhaust (EU31)	9	IVE - 3 hr RVE - 30 min	I & R	C &/or PC
Other				
Fly Ash Transport Blower Discharge - Baghouse Exhaust (EU36)	9	IVE - 30 min RVE - 30 min	I & R	Ash
Fly Ash Silos Bin Vents - Baghouse Exhaust (EU37)	9	IVE - 30 min RVE - 30 min	I & R	Ash
Bed Ash Silos Bin Vents - Baghouse Exhaust (EU38)	9	IVE - 30 min RVE - 30 min	I & R	Ash
AQCS Pebble Lime Silo - Baghouse Exhaust (EU42)	9	IVE - 30 min RVE - 30 min	I & R	Ash
Fly Ash Slurry Mix System Vents – Baghouse Exhaust (EU51)	9	IVE – 60 min RVE – 60 min	I & R	Ash
Bed Ash Slurry Mix System Vents – Baghouse Exhaust (EU52)	9	IVE – 30 min RVE – 30 min	I & R	Ash
Bed Ash Surge Hopper Bin Vents – Baghouse exhaust (EU53)	9	IVE -60 min RVE – 60 min	I & R	Ash

C – Coal and/or Coal coated with latex
I – Initial R - Renewal (once every 5 years)
IVE – Initial Visible Emissions Test, RVE - Renewal Visible Emissions Test
LS – Limestone; PC-Petroleum Coke

Note: No methods other than the ones identified above may be used for compliance testing unless prior DEP or EQD approval is received in writing.

42. Testing Notifications and Capacity: EQD shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). Testing of emissions shall be conducted with the emissions unit operation at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, as determined using fuel flow data and the as-fired heat content of the fuel. If it is impracticable to test at permitted capacity, the unit may be tested at less than permitted capacity. In this case, subsequent operation is limited to 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Compliance test results shall be submitted to EQD no later than 45 days after completion of the last test run. **[Rule 62-297.310, F.A.C.]**

43. Sulfur Content: Vendor or other fuel sampling and analysis data (using applicable ASTM methods) shall be used to determine that the sulfur content of No. 2 fuel oil used in Units 1 and 2 and in the limestone dryers does not exceed 0.05 percent by weight. **[Rule 62-210.200(228), F.A.C.]**

NOTIFICATION, REPORTING AND RECORDKEEPING

44. Records: All measurements, records, and other data required to be maintained by JEA shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP and EQD representatives upon request. **[Rule 62-4.070(3), F.A.C.]**

45. Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed with EQD as soon as practical, but no later than 45 days after the last sampling run is completed. **[Rule 62-297.310(8), F.A.C.]**. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow EQD to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in **Rule 62-297.310(8), F.A.C.**

46. Certification Testing of Monitors: As required under the federal Acid Rain Program, the Acid Rain Monitoring Plan for Northside shall be revised to address the new Continuous Emissions Monitoring Systems (CEMS's) for sulfur dioxide, oxides of nitrogen, and visible emissions (opacity) for Repowered Northside Units 1 and 2. The permittee shall provide a copy of this revised plan, as well as model and serial numbers for each of the monitors, to EQD within 45 days after completion of all certification tests. In addition, the permittee shall provide notification that the carbon monoxide CEMS's meet the performance specifications in 40 CFR Part 60, Appendix B (as applicable), and also provide model and serial numbers to EQD within 45 days after completion of the performance specification tests.

47. NSPS Notifications: The permittee shall provide all notices required under 40 CFR Sections 60.7 and 60.8 (as revised 64 Fed. Reg. 7458, Feb. 12, 1999) to EQD, for each unit subject to an NSPS, including:

    (a) Notification of the date of construction, postmarked no later than 30 days after such date;

    (b) Notification of the anticipated date of initial startup, postmarked not more than 60 days nor less than 30 days prior to such date; and

    (c) Notification of the actual date of initial startup, postmarked within 15 days after such date.

    (d) Notification of any performance test at least 30 days prior to the test and at least 7 days prior notice if a test postponed due to a delay or otherwise by mutual agreement between the permittee and EQD.

48. Quarterly Compliance Reports for Annual Limits: The permittee shall provide reports quarterly to EQD certifying compliance with the 12-month rolling limits on SO_2, NOx and PM (TSP) for Northside Units 1, 2, and 3 set forth in Conditions 14(b), 15(b), and 16(b). The reports shall be submitted within 45 days after the last day of each calendar quarter. **[Applicant request.]**

49. The permittee shall provide an engineering study by December 31, 2010 to the Department and EQD detailing opportunities to increase the reliability and availability of the SDA system. The study will address potential improvements in preventive and predictive maintenance, and potential equipment and system modifications (including opportunities for redundancy) which will result in minimizing the amount of time the SDA is off-line during CFB operation. The engineering study shall also include the cost estimates associated with potential equipment/system modifications (including opportunities for redundancy) and the cost effectiveness of the associated emissions reductions. **[Rule 62-4.070(3), F.A.C.; and 0310045-022-AC/PSD-FL-265E]**

CONTINUOUS EMISSIONS MONITORING SYSTEMS REQUIREMENT AND REPORTING

50.(a) Continuous Emissions Monitoring Systems Requirement: The permittee shall install, calibrate, operate, and maintain Continuous Emission Monitoring Systems (CEMS) in the stack to measure and record the sulfur dioxide, oxides of nitrogen, carbon monoxide, mercury (Hg) and visible emissions from Units 1 and 2. An emission level above a BACT limit, considering the 6-minute, 24-hour and 30-day rolling average periods, as applicable, shall be reported to EQD pursuant to Rule 62-4.160(8), F.A.C. The continuous emission monitoring systems shall comply with the certification, performance specifications, and quality assurance, and other applicable requirements of 40 CFR Part 75 and 40 CFR Part 60 (Appendix B), as indicated above. Periods of startup, shutdown, and malfunction shall be monitored, recorded, and reported as excess emissions when emission levels exceed the limits in Table 1 following the format of 40 CFR 60.7 (As revised, 64 Fed Reg. 7458 (Feb. 12, 1999)).

(b) Hg Continuous Emissions Monitoring Systems Operation: The permittee has voluntarily agreed to install and operate a Hg CEMS on Units 1 and 2. The Hg CEMS shall be installed and operational no later than March 31, 2009, and shall be operated in accordance with the quality assurance/quality control (QA/QC) plan submitted by JEA and approved by the Department. The approved QA/QC plan will become part of the permit and any future revisions to the QA/QC plan that are approved by the Department will also be part of the permit. This requirement will stay in effect until such time that the state or EPA passes a regulatory requirement for mercury detailing the Hg CEMS operational protocol, at which time that rule will become the preferred protocol. The annual relative accuracy test required by the QA/QC plan can be performed by the permittee under the normal mode of operation. For JEA, the normal mode of operation is firing a fuel blend which is typically 15% coal and 85% petroleum coke. Every reasonable effort should be made by the permittee for the Hg CEMS to be operating during the time periods when the SDA is off-line. If the Hg CEMS is not operating during a time period when the SDA is taken off-line, the best estimate of Hg emissions shall be provided to the Department and EQD based on the requirements of Rule 62-210.370, F.A.C. **[Rules 62-4.070(3) and 62-210.370, F.A.C.; and 0310045-022-AC/PSD-FL-265E]**

(c) Continuous Emissions Monitoring Systems Reporting: JEA shall submit to the Department and EQD the Hg CEMS emissions data for both Units 1 and 2. It shall be submitted in a graphical representation of Hg emissions against time. The graph shall also indicate the periods when the SDA was taken off-line. The four quarterly Hg CEMS data shall be submitted starting on June 30, 2009 and ending on June 30, 2010 and thereafter Hg CEMS data shall be submitted semi-annually until June 2012. The submittal of Hg CEMS data after June 2012 will be only upon request from the Department or EQD. **[Rule 62-4.070(3), F.A.C.; and 0310045-022-AC/PSD-FL-265E]**

51. Determination of Process Variables:

(a) The permittee shall operate and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Equipment or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. **[Rule 62-297.310(5), F.A.C]**

ATTACHMENT JEA-EU2-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT JEA-EU2-IV3

ALTERNATIVE METHODS OF OPERATION

NGS - CFB Boiler Nos. 1 and 2 are permitted to operate while firing coal, coal treated with a latex binder, and petroleum coke. In addition, these units can burn natural gas (including landfill gas) and distillate fuel oil.

ATTACHMENT A

ATTACHMENT A

SUPPLEMENTAL INFORMATION FOR CONSTRUCTION PERMIT APPLICATION

I. INFORMATION FOR AIR CONTRUCTION PERMIT APPLICATION

PROJECT DESCRIPTION

Jacksonville Electric Authority (JEA) currently operates the Northside Generating Station (NGS), St. John's River Power Park (SJRPP), and Separation Technologies, Inc. under Title V operating permit No. 0310045-020-AV. JEA currently operates CFB Boiler Nos. 1 and 2 (EU 027 and 026) at NGS, among other sources. The boilers are permitted to burn coal, petroleum coke, No. 2 fuel oil, and natural gas.

JEA is requesting the ability to add landfill gas as an allowable fuel to burn in the CFB boilers. JEA is requesting to burn a maximum of 0.012 million cubic feet per hour of landfill gas (total both boilers). The boilers are already permitted to burn natural gas, which results in the same or higher emissions on a pounds per million British thermal units (lb/MMBtu) basis compared to landfill gas. Therefore, there will be no increase in maximum hourly or annual emissions for any pollutant as a result of the project. The sulfur dioxide (SO_2) emission limits for boiler Nos. 1 and 2 will continue to be met through limestone injection in the CFBs and in the spray dryer adsorbers.

The maximum design heat input rates to CFB Boiler Nos. 1 and 2 will not change as a result of the project. The heat input rate to the each boiler is currently 2,764 million British thermal units per hour (MMBtu/hr).

The burning of landfill gas will require no physical changes to be made to the boilers. The capacity of the boilers will not be affected by this change.

JEA does not expect emissions of any air pollutant to increase as a result of this project.

II. INFORMATION FOR TITLE V PERMIT APPLICATION

JEA is requesting through this permit revision to:

- Incorporate the provisions of Air Construction Permit Nos. 0310045-017-AC, 0310045-022-AC, 0310045-024-AC, and 0310045-025-AC into the current Title V Operating Permit.
- Include EPA Method CTM-013 (Method 8A) for the determination of sulfuric acid mist emissions in lieu of EPA Method 8, per consent order 09-I-AP.
- Remove Table 6-Part C in Appendix SJRPP of the current Title V permit, and revise Table 6-Part B in the same appendix for the material handling operations. The points listed in the original Table 6C were never constructed. The revised Table 6-Part B is attached.
- Allow landfill gas to be burned in CFB Boiler Nos. 1 and 2 (EU Nos. 027, 026).

Revised Table 6 - Part B. SJRPP: Materials Handling and Storage Operations

Emission Unit No.	Material Handling and Storage Emission Unit	Type Source	Opacity Limit (%)	AQCS	VE Testing Frequency	Rationale
022: SJRPP: Bottom Ash, Fly Ash and Gypsum Handling and Storage Operations						
022a	Gypsum Dewatering Building	Fugitive	5	1	Upon Request	Wet byproduct w/insignificant emissions
022a	Gypsum Storage Enclosure	Fugitive	5	1	Upon Request	Wet byproduct w/insignificant emissions
022j	Gypsum Truck Loadout	Fugitive	5	1	Upon Request	Wet byproduct w/insignificant emissions
022j	Fly Ash Loadout for Silo 1A (metal structure)	Fugitive	10	1 & 3	Upon Request	Emissions vented back to Saleable Ash Silo
022j	Fly Ash Loadout for Silo 1B (metal structure)	Fugitive	10	1 & 3	Upon Request	Emissions vented back to Saleable Ash Silo
022j	Fly Ash Loadout for Silo 2A (metal structure)	Fugitive	10	1 & 3	Upon Request	Emissions vented back to Saleable Ash Silo
022j	Fly Ash Loadout for Silo 2B (metal structure)	Fugitive	10	1 & 3	Upon Request	Emissions vented back to Saleable Ash Silo
022k	Solid Waste Disposal Area	Fugitive	10	1 & 2	Upon Request	Wet byproduct w/insignificant emissions
022l	*Saleable Fly Ash Silo 1A with Fabric Filter (concrete structure)*	Point-Vent	5	4 & 5	Annually	Vent with minor emissions
022l	*Saleable Fly Ash Silo 1B with Fabric Filter (concrete structure)*	Point-Vent	5	4 & 5	Annually	Vent with minor emissions
022l	*Saleable Fly Ash Silo 2A with Fabric Filter (concrete structure)*	Point-Vent	5	4 & 5	Annually	Vent with minor emissions
022l	*Saleable Fly Ash Silo 2B with Fabric Filter (concrete structure)*	Point-Vent	5	4 & 5	Annually	Vent with minor emissions
022l	*Non-Saleable Fly Ash Silo Unit 1-A with Fabric Filter (concrete structure)*	Point-Vent	5	4 & 5	Annually	Vent with minor emissions
022l	*Non-Saleable Fly Ash Silo Unit 2-A with Fabric Filter (concrete structure)*	Point-Vent	5	4 & 5	Annually	Vent with minor emissions
022m	*Wet Fly Ash Load out 1A/1B*	Fugitive	10	1, 4 & 6	Upon Request	Wet byproduct w/insignificant emissions
022m	Bottom Ash Loadouts 1A/1B	Fugitive	10	1	Upon Request	Wet byproduct w/insignificant emissions
022m	*Wet Fly Ash Load out 2A/2B*	Fugitive	10	1, 4 & 6	Upon Request	Wet byproduct w/insignificant emissions
022m	Bottom Ash Loadouts 2A/2B	Fugitive	10	1	Upon Request	Wet byproduct w/insignificant emissions
022n	Unpaved Road, By-Product Transport	Fugitive	10	1 & 2	Upon Request	No emission vent, reasonable Precautions conducted (watering)
023: SJRPP: Materials Handling and Storage Operations						
023a	Rail Rotary Dumper - Building Emissions	Point-Fugitive	10	1,2,4,&6	Upon Request	No emissions vent, minor emissions
023b	Conveyor C-3 Tunnel Ventilation - 6,400 cfm; No control	Point-Vent	5	1, 4, & 5	Upon Renewal of Title V	Provides tunnel ventilation only, minor emissions
023b	Conveyor C-3 Tunnel Ventilation - 6,400 cfm; No control	Point-Vent	5	1, 4, & 5	Upon Renewal of Title V	Provides tunnel ventilation only, minor emissions
023b	Conveyor C-3 Tunnel Ventilation - 21,600 cfm; No control	Point-Vent	5	1, 4, & 5	Upon Renewal of Title V	Provides tunnel ventilation only, minor emissions
023c	Shiphold	Fugitive	10	1, 4 & 6	Upon Request	No emissions vent, minor emissions
023d	Unloader Hopper and Spillage Collector Transfers	Fugitive	10	1, 3, 4 & 6	Upon Request	No emissions vent, minor emissions
023d	Ship Unloader Hopper to Transfer CT-1, Spillage Conveyor	Fugitive	10	1, 3, 4 & 6	Upon Request	Enclosed conveyor, no emissions vent
023e	Fuel Transfer Building (DC-2)	Fugitive	10	1, 3 & 4	Upon Request	No emissions vent, minor emissions, enclosed source
023e	Transfer Station No. 1	Fugitive	5	1, 2 & 4	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 2	Fugitive	5	1, 2 & 4	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 3	Fugitive	5	1, 2 & 4	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 4	Fugitive	5	1 & 4	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 5	Fugitive	5	1 & 4	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 6	Fugitive	5	1 & 4	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Station No. 7	Fugitive	5	1 & 4	Upon Request	Enclosed conveyor, no emissions vent
023e	Transfer Point 9GC-04 to 9GC-05	Fugitive	5	1	Upon Request	No emissions vent, minor emissions (gypsum)
023f	Stacker/Reclaimer (Stacker Mode)	Fugitive	10	1 & 3	Upon Request	No emissions vent, minor emissions
023f	Stacker	Fugitive	10	1 & 3	Upon Request	No emissions vent, minor emissions
023f	Reclaimer	Fugitive	10	1 & 3	Upon Request	No emissions vent, minor emissions
~~023g~~	~~Petroleum Coke Reclaimer System (PC-1)~~	~~Fugitive~~	~~10~~	~~1~~	~~Upon Request~~	~~No emissions vent, minor emissions~~ Source Eliminated
023g	Emergency Reclaim Hoppers - Loadout	Fugitive	10	1	Upon Request	Same as other reclaim systems; not typically used
023j	Limestone Truck Loadout & Transfer	Fugitive	10	1	Upon Request	No emissions vent, minor emissions
023k	Limestone Storage Pile #1 - Existing	Fugitive	10	1	Upon Request	No emissions location, minor emissions
023k	Limestone Storage Pile #2 - Fuel yard	Fugitive	10	1, 2 & 3	Upon Request	No emissions location, minor emissions, not currently used.
023k	*Limestone Reclaim Loadout - Grizzley*	Fugitive	10	1 & 3	Upon Request	Minor emissions
023k	Coal Pile	Fugitive	10	1, 2 & 3	Upon Request	No emissions location, minor emissions
023k	Petroleum Coke Pile	Fugitive	10	1, 2 & 3	Upon Request	No emissions location, minor emissions
023l	Limestone Reclaim Hopper with Fabric Filter (3DC-01)	Point-Vent	5	1, 4 & 5	Annually	Vent with minor emissions
023l	*Limestone Silos with Fabric Filters (2: 1DC-01 and 2DC-01)*	Point-Vent	5	1, 4 & 5	Annually	Minor emissions
023l	*Quick Lime Silo with Filter Vent (used for water treatment)*	Point-Vent	5	4 & 5	Upon Renewal of Title V	Minor emission source, low volume material handling; 15 min VE suggested
023l	Fuel Handling Building with Fabric Filter (DC-3)	Point-Vent	5	1, 4 & 5	Annually	Vent with minor emissions
023l	Unit #1 Fuel Storage Bins with Fabric Filter (DC-4)	Point-Vent	5	1, 4 & 5	Annually	Vent with minor emissions
023l	Unit #2 Fuel Storage Bins with Fabric Filter (DC-5)	Point-Vent	5	1, 4 & 5	Annually	Vent with minor emissions

NOTE:

a. "*Italics*" indicates that the emission point was not included in Revised Table 6 of PSD-FL-010(C), but is associated with the material handling and storage operations at SJRPP.

b. The VE limit (% opacity) shall be used for compliance purposes and demonstrated using EPA Reference Method 9, pursuant to 40 CFR Part 60, Appendix A, and Chapter 62-297, F.A.C.

c. **Air Quality Control Systems (AQCS)**

1. Conditioned Materials
2. Wet Suppression
3. Water Sprays
4. Enclosures (Total, Partial, Covers, & Wind Screens)
5. Dust Control Systems
6. Best Operating Practices